ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044, FRL–9611–4]

RIN 2060–AP52; RIN 2060–AR31

National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On May 3, 2011, under authority of Clean Air Act (CAA) sections 111 and 112, the EPA proposed both national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs) and standards of performance for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units (76 FR 24976). After consideration of public comments, the EPA is finalizing these rules in this action.

Pursuant to CAA section 111, the EPA is revising standards of performance in response to a voluntary remand of a final rule. Specifically, we are amending new source performance standards (NSPS) after analysis of the public comments we received. We are also finalizing several minor amendments, technical clarifications, and corrections to existing NSPS provisions for fossil fuel-fired EGUs and large and small industrial-commercial-institutional steam generating units.

Pursuant to CAA section 112, the EPA is establishing NESHAP that will require coal- and oil-fired EGUs to meet hazardous air pollutant (HAP) standards reflecting the application of the maximum achievable control technology. This rule protects air quality and promotes public health by reducing emissions of the HAP listed in CAA section 112(b)(1).

DATES: This final rule is effective on April 16, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of April 16, 2012.

ADDRESSES: The EPA established two dockets for this action: Docket ID. No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP action). All documents in the dockets are listed on the *http://www.regulations.gov* Web site. Although listed in the index, 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 *http://www.regulations.gov* or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1741.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5430; Fax number (919) 541–5450; Email address: *maxwell.bill@epa.gov.* For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4003; Fax number (919) 541–5450; Email address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION:

The information presented in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by the final standards are shown in Table 1 of this preamble.

TABLE 1—POTENTIALLY AFFECTED REGULATED CATEGORIES AND ENTITIES

Category	NAICS code [1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by the federal government.
State/local/tribal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by states, tribes, or municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

[1] North American Industry Classification System.

[2] Federal, state, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather is meant to provide a guide for readers regarding entities likely to be affected by this action. To determine whether you, as owner or operator of a facility, company, business, organization, etc., will be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9981. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the dockets, an electronic copy of this action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature by the Administrator, a copy of the action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/.* The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 16, 2012. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f 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 to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20004, with a copy to the person 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), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note, 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 EPA to enforce these requirements.

D. What are the costs and benefits of this final rule?

Consistent with Executive Order (EO) 13563, ''Improving Regulation and Regulatory Review,'' we have estimated the costs and benefits of the final rule. This rule will reduce emissions of HAP, including mercury (Hg), from the electric power industry. Installing the technology necessary to reduce emissions directly regulated by this rule will also reduce the emissions of directly emitted $PM_{2.5}$ and sulfur dioxide (SO_2), a $PM_{2.5}$ precursor. The benefits associated with these PM and SO_2 reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA estimates that this final rule will yield annual monetized benefits (in 2007$) of between $37 to $90 billion using a 3 percent discount rate and $33 to $81 billion using a 7 percent discount rate. The great majority of the estimates are attributable to co-benefits from reductions in $PM_{2.5}$-related mortality. The annual social costs, approximated by the sum of the compliance costs and monitoring and reporting costs, are $9.6 billion (2007$) and the annual quantified net benefits (the difference between benefits and costs) are $27 to $80 billion using a 3 percent discount rate or $24 to $71 billion using a 7 percent discount rate. It is important to note that the $PM_{2.5}$ co-benefits reported here contain uncertainty, due in part to the important assumption that all fine particles are equally potent in causing premature mortality and because many of the benefits are associated with reducing $PM_{2.5}$ levels at the low end of the concentration distributions examined in the epidemiology studies from which the $PM_{2.5}$-mortality relationships used in this analysis are derived.

The benefits of this rule outweigh costs by between 3 to 1 or 9 to 1 depending on the benefit estimate and discount rate used. The co-benefits are substantially attributable to the 4,200 to 11,000 fewer $PM_{2.5}$-related premature mortalities estimated to occur as a result of this rule. The EPA could not monetize some costs and important benefits, such as some Hg benefits and those for the HAP reduced by this final rule other than Hg. Upon considering these limitations and uncertainties, it remains clear that the benefits of this rule, referred to in short as the Mercury and Air Toxics Standards (MATS), are substantial and far outweigh the costs.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS, AND NET BENEFITS FOR THE FINAL RULE IN 2016

[Billions of 2007$] [a]

	3% Discount rate	7% Discount rate
Total Monetized Benefits [b]	$37 to $90	$33 to $81.
Partial Hg-related Benefits [c]	$0.004 to $0.006	$0.0005 to $0.001.
$PM_{2.5}$-related Co-benefits [b]	$36 to $89	$33 to $80.
Climate-related Co-Benefits [d]	$0.36	$0.36.
Total Social Costs [e]	$9.6	$9.6.
Net Benefits	$27 to $80	$24 to $71.
Non-monetized Benefits	Visibility in Class I areas. Other neurological effects of Hg exposure. Other health effects of Hg exposure. Health effects of ozone and direct exposure to SO_2 and NO_2. Ecosystem effects. Health effects from commercial and non-freshwater fish consumption. Health risks from exposure to non-mercury HAP.	

[a] All estimates are for 2016, and are rounded to two significant figures.

[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits. Benefits in this table are nationwide and are associated with directly emitted $PM_{2.5}$ and SO_2 reductions. The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in chapter 5 of the RIA. Mercury benefits were calculated using the baseline from proposal. The difference in emissions reductions between proposal and final does not substantially affect the Hg benefits.

[c] Based on an analysis of health effects due to recreational freshwater fish consumption.

[d] This table shows monetized CO_2 co-benefits that were calculated using the global average social cost of carbon estimate at a 3 percent discount rate. In section 5.6 of the Regulatory Impact Analysis (RIA) we also report the monetized CO_2 co-benefits using discount rates of 5 percent, 2.5 percent, and 3 percent (95th percentile).

[e] Total social costs are approximated by the compliance costs for both coal- and oil-fired units. This includes monitoring, recordkeeping, and reporting costs.

For more information on how EPA is addressing EO 13563, see the EO discussion in the Statutory and Executive Order Reviews section of this preamble.

II. Background Information on the NESHAP

On May 3, 2011, the EPA proposed this rule to address emissions of toxic air pollutants from coal and oil-fired electric generating units as required by the CAA. The proposal explained at length the statutory history and requirements leading to this rule, the factual and legal basis for the rule and its specific provisions, and the costs and benefits to the public health and environment from the proposed requirements.

The EPA received over 900,000 comments from members of the public on the proposed rule, substantially more than for any other prior regulatory proposal. The comments express concerns about the presence of Hg in the environment and the effect it has on human health, concerns about the costs of the rule, how challenging it may be for some sources to comply and questions about the impact it may have on this country's electricity supply and economy. Many comments provided additional information and data that have enriched the factual record and enabled EPA to finalize a rule that fulfills the mandate of the CAA while providing flexibility and compliance options to affected sources—options that make the rule less costly and compliance more readily manageable.

This rule establishes uniform emissions-control standards that sources can meet with proven and available technologies and operational processes in a timeframe that is achievable. They will put this industry, now the single largest source of Hg emissions in the United States (U.S.) with emissions of 29 tons per year, on a path to reducing those emissions by approximately 90 percent. Emissions of other toxic metals, such as arsenic (As) and nickel (Ni), dioxins and furans, acid gases (including hydrochloric acid (HCl) and SO_2) will also decrease dramatically with the installation of pollution controls. And the flexibilities established in this rule along with other available tools provide a clear pathway to compliance without jeopardizing the country's energy supply.

This preamble explains EPA's appropriate and necessary finding, the elements of the final rule, key changes the EPA is making in response to comments submitted on the proposed rule, and our responses to many of the comments we received. A full response to comments is provided in the response to comments document available in the docket for this rulemaking.

A. What is the statutory authority for this final rule?

Congress established a specific structure for determining whether to regulate EGUs under CAA section 112.[1] Specifically, Congress enacted CAA section 112(n)(1).

Section 112(n)(1)(A) of the CAA requires the EPA to conduct a study to evaluate the remaining public health hazards that are reasonably anticipated to occur as a result of EGUs' HAP emissions after imposition of CAA requirements. The EPA must report the results of that study to Congress, and regulate EGUs ''if the Administrator finds such regulation is appropriate and necessary,'' after considering the results of that study. Thus, CAA section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under CAA section 112. *See New Jersey* v. *EPA*, 517 F.3d 574 at 582 (D.C. Cir. 2008) (''Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs.'').

As directed, the EPA conducted the study to evaluate the remaining public health hazards and reported the results to Congress (Utility Study Report to Congress (Utility Study)).[2] We discuss this study below in conjunction with other studies that CAA section 112(n)(1) requires concerning EGUs. See also 76 FR 24982–24984 (summarizing studies).

Once the EPA lists a source category pursuant to CAA section 112(c), the EPA must then establish technology-based emission standards under CAA section 112(d). For major sources, the EPA must establish emission standards that ''require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section'' that the EPA determines are achievable taking into account certain statutory factors. *See* CAA section 112(d)(2). These standards are referred to as ''maximum achievable control technology'' or ''MACT'' standards. The MACT standards for existing sources must be at least as stringent as the average emission limitation achieved by the best performing 12 percent of existing sources in the category (for which the Administrator has emissions information) or the best performing 5 sources for source categories with less than 30 sources. *See* CAA section 112(d)(3)(A) and (B), respectively. This level of minimum stringency is referred to as the ''MACT floor,'' and the EPA cannot consider cost in setting the floor. For new sources, MACT standards must be at least as stringent as the control level achieved in practice by the best controlled similar source. *See* CAA section 112(d)(3).

The EPA also must consider more stringent ''beyond-the-floor'' control options. When considering beyond-the-floor options, the EPA must consider the maximum degree of reduction in HAP emissions and take into account costs, energy, and non-air quality health and environmental impacts when doing so. *See Cement Kiln Recycling Coal.* v. *EPA*, 255 F.3d 855, 857–58 (D.C. Cir. 2001).

Alternatively, the EPA may set a health-based standard for HAP that have an established health threshold, and the standard must provide ''an ample margin of safety.'' *See* CAA section 112(d)(4). As these standards could be less stringent than MACT standards, the Agency must have detailed information on HAP emissions from the subject sources and sources located near the subject sources before exercising its discretion to set such standards.

For area sources, the EPA may issue standards or requirements that provide for the use of generally available control technologies or management practices (GACT standards) in lieu of promulgating MACT or health-based standards. *See* CAA section 112(d)(5).

As noted above, CAA section 112(n) requires completion of various reports concerning EGUs. For the first report, the Utility Study, Congress required the EPA to evaluate the hazards to public health reasonably anticipated to occur as the result of HAP emissions from EGUs after imposition of the requirements of the CAA. *See* CAA section 112(n)(1)(A). The EPA was required to report results from this study to Congress by November 15, 1993. *Id.* Congress also directed the EPA to conduct ''a study of mercury emissions from [EGUs], municipal waste combustion units, and other sources, including area sources'' (Mercury Study). *See* CAA section 112(n)(1)(B). The EPA was required to report the results from this study to Congress by November 15, 1994. *Id.* In conducting this Mercury Study, Congress directed the EPA to ''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.'' *Id.* Congress directed the National Institute of Environmental Health Sciences (NIEHS) to conduct the last required evaluation, ''a study to determine the threshold level of mercury exposure below which adverse human health effects are not expected to occur'' (NIEHS Study). *See* CAA section 112(n)(1)(C). The NIEHS was required to submit the results to Congress by November 15, 1993. *Id.* In conducting this study, NIEHS was to determine ''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.'' *Id.*

In addition, Congress, in conference report language associated with the EPA's fiscal year 1999 appropriations, directed the EPA to fund the National Academy of Sciences (NAS) to perform an independent evaluation of the available data related to the health impacts of methylmercury (MeHg) (NAS Study or MeHg Study). H.R. Conf. Rep. No 105–769, at 281–282 (1998). Specifically, Congress required NAS to advise the EPA as to the appropriate reference dose (RfD) for MeHg. 65 FR 79826. The RfD is the amount of a chemical which, when ingested daily over a lifetime, is anticipated to be without adverse health effects to humans, including sensitive subpopulations. In the same conference report, Congress indicated that the EPA should not make the appropriate and necessary regulatory determination for Hg emissions until the EPA had reviewed the results of the NAS Study. *See* H.R. Conf. Rep. No 105–769, at 281–282 (1998).

As directed by Congress through different vehicles, the NAS Study and the NIEHS Study evaluated the same issues. The NIEHS completed the NIEHS Study in 1995,[3] and the NAS completed the NAS Study in 2000.[4] Because NAS completed its study 5 years after the NIEHS Study, and considered additional information not earlier available to NIEHS, for purposes of this document we discuss the content of the NAS Study as opposed to the NIEHS Study.

The EPA conducted the studies required by CAA section 112(n)(1) concerning utility HAP emissions, the Utility Study and the Mercury Study,[5] and completed both by 1998. Prior to issuance of the Mercury Study, the EPA

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[1] ''Electric utility steam generating unit'' is defined, in part, as any ''fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.'' *See* CAA section 112(a)(8).

[2] U.S. EPA. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress. EPA–453/R–98–004a. February 1998.

[3] NIEHS Study, August 1995; EPA–HQ–OAR–2009–3053.

[4] National Research Council (NAS). 2000. Toxicological Effects of Methylmercury. Committee on the Toxicological Effects of Methylmercury, Board on Environmental Studies and Toxicology, National Research Council.

[5] Mercury Study Report to Congress, December 1997; EPA–HQ–OAR–2009–0234–3054.

engaged in two extensive external peer reviews of the document.

On December 20, 2000, the EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under CAA section 112(d). In making that finding, the EPA considered the Utility Study, the Mercury Study, the NAS Study, and certain additional information, including information about Hg emissions from coal-fired EGUs that the EPA obtained pursuant to an information collection request (ICR) under the authority of CAA section 114. 65 FR 79826–27.

B. What is the litigation history of this final rule?

Shortly after issuance of the December 2000 finding, an industry group challenged that finding in the Court of Appeals for the D.C. Circuit (D.C. Circuit). *Utility Air Regulatory Group (UARG)* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001). The D.C. Circuit dismissed the lawsuit holding that it did not have jurisdiction because CAA section 112(e)(4) provides, in pertinent part, that ''no action of the Administrator * * * listing a source category or subcategory under subsection (c) of this section *shall be a final agency action subject to judicial review*, except that any such action may be reviewed under section 7607 of (the CAA) when the Administrator issues emission standards for such pollutant or category.'' *Id. (emphasis added).*

Pursuant to a settlement agreement, the deadline for issuing emission standards was March 15, 2005. However, instead of issuing emission standards pursuant to CAA section 112(d), on March 29, 2005, the EPA issued the Section 112(n) Revision Rule (2005 Action). That action delisted EGUs after finding that it was neither appropriate nor necessary to regulate such units under CAA section 112. In addition, on May 18, 2005, the EPA issued the Clean Air Mercury Rule (CAMR). 70 FR 28606. That rule established standards of performance for emissions of Hg from new and existing coal-fired EGUs pursuant to CAA section 111.

Environmental groups, states, and tribes challenged the 2005 Action and CAMR. Among other things, the environmental and state petitioners argued that the EPA could not remove EGUs from the CAA section 112(c) source category list without following the requirements of CAA section 112(c)(9).

On February 8, 2008, the D.C. Circuit vacated both the 2005 Action and CAMR. The D.C. Circuit held that the EPA failed to comply with the requirements of CAA section 112(c)(9) for delisting source categories. Specifically, the D.C. Circuit held that CAA section 112(c)(9) applies to the removal of ''any source category'' from the CAA section 112(c) list, including EGUs. The D.C. Circuit found that, by enacting CAA section 112(c)(9), Congress limited the EPA's discretion to reverse itself and remove source categories from the CAA section 112(c) list. The D.C. Circuit found that the EPA's contrary position would ''nullify § 112(c)(9) altogether.'' *New Jersey* v. *EPA*, 517 F.3d 574, 583 (D.C. Cir. 2008). The D.C. Circuit did not reach the merits of petitioners' arguments on CAMR, but vacated CAMR for existing sources because coal-fired EGUs were already listed sources under CAA section 112. The D.C. Circuit reasoned that even under the EPA's own interpretation of the CAA, regulation of existing sources' Hg emissions under CAA section 111 was prohibited if those sources were a listed source category under CAA section 112.[6] *Id.* The D.C. Circuit vacated and remanded CAMR for new sources because it concluded that the assumptions the EPA made when issuing CAMR for new sources were no longer accurate (*i.e.*, that there would be no CAA section 112 regulation of EGUs and that the CAA section 111 standards would be accompanied by standards for existing sources). *Id.* at 583–84. Thus, CAMR and the 2005 Action became null and void.

On December 18, 2008, several environmental and public health organizations filed a complaint in the U.S. District Court for the District of Columbia.[7] They alleged that the Agency had failed to perform a nondiscretionary duty under CAA section 304(a)(2), by failing to promulgate final CAA section 112(d) standards for HAP from coal- and oil-fired EGUs by the statutorily-mandated deadline, December 20, 2002, 2 years after such sources were listed under CAA section 112(c). The EPA settled that litigation. The consent decree resolving the case requires the EPA to sign a notice of proposed rulemaking setting forth the EPA's proposed CAA section 112(d) emission standards for coal- and oil-fired EGUs by March 16, 2011, and a notice of final rulemaking by December 16, 2011.[8]

C. What is the relationship between this final rule and other combustion rules?

1. CAA Section 111

The EPA promulgated revised NSPS for SO_2, nitrogen oxides (NO_X), and PM under CAA section 111 for EGUs (40 CFR part 60, subpart Da) and industrial boilers (IB) (40 CFR part 60, subparts Db and Dc) on February 27, 2006 (71 FR 9866). As noted elsewhere, in this action we are finalizing certain amendments to 40 CFR part 60, subpart Da. In developing this final rule, we considered the monitoring, testing, and recordkeeping requirements of the existing and revised NSPS to avoid duplicating requirements to the extent possible.

2. CAA Section 112

The EPA has previously developed other non-EGU combustion-related NESHAP under CAA section 112(d). The EPA promulgated final NESHAP for major source industrial, commercial and institutional boilers and process heaters (IB) and area source industrial, commercial and institutional boilers on March 21, 2011 (40 CFR part 63, subpart DDDDD, 76 FR 15608; and subpart JJJJJJ, 76 FR 15249, respectively), and promulgated standards for stationary combustion turbines (CT) on March 5, 2004 (40 CFR part 63 subpart YYYY; 69 FR 10512). In addition to these three NESHAP, on March 21, 2011, the EPA also promulgated final CAA section 129 standards for commercial and institutional solid waste incineration (CISWI) units, including energy recovery units (40 CFR part 60, subparts CCCC (NSPS) and DDDD (emission guidelines); 76 FR 15704); and a definition of non-hazardous secondary materials that are solid waste (Non-hazardous Solid Waste Definition Rule (40 CFR part 241, subpart B; 76 FR 15456)). Electric generating units and IB

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[6] In CAMR and the 2005 Action, EPA interpreted section 111(d) of the Act as prohibiting the Agency from establishing an existing source standard of performance under CAA section 111(d) for any HAP emitted from a particular source category, if the source category is regulated under CAA section 112.

[7] American Nurses Association, Chesapeake Bay Foundation, Inc., Conservation Law Foundation, Environment America, Environmental Defense Fund, Izaak Walton League of America, Natural Resources Council of Maine, Natural Resources Defense Council, Physicians for Social Responsibility, Sierra Club, The Ohio Environmental Council, and Waterkeeper Alliance, Inc. (Civ. No. 1:08–cv–02198 (RMC)).

[8] The consent decree originally required EPA to sign a notice of final rulemaking no later than November 16, 2011; however, on October 21, 2011, pursuant to paragraph 6 of the consent decree, the parties agreed to a 30-day extension of the final rule deadline. As stated in the stipulation memorializing the extension, the parties agreed to the extension of 30 days because EPA provided an additional 30 days for public comment and the time was necessary to respond to comments submitted on the proposed rule.

that combust fossil fuel and solid waste, as that term is defined by the Administrator pursuant to the Resource Conservation and Recovery Act (RCRA), *see* 76 FR 15456, will be subject to standards issued pursuant to CAA section 129 (*e.g.*, CISWI), unless they meet one of the exemptions in CAA section 129(g)(1). Clean Air Act section 129 standards are discussed in more detail below.

The two IB (Boiler) NESHAP, the CT NESHAP, and this final rule will regulate HAP emissions from sources that combust fossil fuels for electrical power, process operations, or heating. The differences among these rules are due to the size of the units (megawatt (MW), megawatt-electric (MWe), or British thermal unit per hour (Btu/hr)), the boiler/furnace technology, and/or the portion of their electrical output (if any) for sale to any utility power distribution systems.

Pursuant to the CAA, an EGU is ''any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.'' CAA section 112(a)(8). We consider all of the MW ratings quoted in the final rule to be the original rated nameplate capacity of the unit. We consider cogeneration to be the simultaneous production of power (electricity) and another form of useful thermal energy (usually steam or hot water) from a single fuel-consuming process.

We consider any combustion unit, regardless of size, that produces steam to serve a generator that produces electricity exclusively for industrial, commercial, or institutional purposes (*i.e.*, makes no sales to the national electrical distribution grid) to be an IB unit. We do not consider a fossil fuel-fired combustion unit that serves a generator that produces electricity for sale to be an EGU under the final rule if the size of the combustion unit is less than or equal to 25 MW. Units that are 25 MW or less are likely subject to one of the two Boiler NESHAP.

Because of the combustion technology of simple-cycle and combined-cycle stationary CTs (with the exception of integrated gasification combined cycle (IGCC) units that burn gasified coal or petroleum coke synthesis gas/syngas), we do not consider these CTs to be EGUs for purposes of this final rule.[9]

The December 2000 listing discussed above did not list natural gas-fired EGUs. Thus, this final rule does not regulate a unit that otherwise meets the CAA section 112(a)(8) definition of an EGU but that combusts natural gas exclusively or natural gas in combination with another fossil fuel where the natural gas constitutes 90.0 percent or more of the average annual heat input during any 3 consecutive calendar years or 85.0 percent or more of the annual heat input in one calendar year. We consider such units to be natural gas-fired EGUs notwithstanding the combustion of some coal or oil (or derivative thereof) and such units are not subject to this final rule.

The CAA does not define the terms ''fossil fuel-fired'' and ''fossil fuel.'' In this rule, we are finalizing definitions for both terms for purposes of this rule. The definition of ''fossil fuel-fired'' will help determine the applicability of the final rule to combustion units that sell electricity to the utility power distribution system. The definition of ''fossil fuel-fired'' establishes the amount of fossil fuel combustion necessary to make a unit ''fossil fuel-fired'' and hence potentially subject to this final rule. These definitions will help determine applicability of the final rule to units that primarily fire non-fossil fuels (*e.g.*, biomass) but generally start up using either natural gas or distillate oil and may use these fuels (or coal) during normal operation for flame stabilization.

In addition, the EPA is finalizing in the definition of ''fossil fuel-fired'' that, among other things, an EGU must fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date in order to be considered a fossil fuel-fired EGU subject to this final rule. The EPA has based these threshold percentage values on the definition of ''oil-fired'' in the Acid Rain Program (ARP) found at 40 CFR 72.2. Though the EPA does not have annual heat input data for, for example, biomass co-fired EGUs because their use is not yet commonplace, we believe this definition accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this final rule.

Units that do not meet the EGU definition will in most cases be considered IB units subject to one of the two Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.*, less than or equal to 10.0 percent of the average annual heat input in any 3 consecutive calendar years or less than or equal to 15.0 percent of the annual heat input during any one calendar year) is not considered to be a fossil fuel-fired EGU under this final rule.

A cogeneration facility that sells electricity to any utility power distribution system equal to more than one-third of its potential electric output capacity and more than 25 MW will be considered an EGU if the facility is fossil fuel-fired as that term is defined in the final rule.

We recognize that different CAA section 112 rules may impact a particular unit at different times. For example, the Boiler NESHAP may cover some cogeneration units. Such a unit may decide to increase or decrease the proportion of production output it supplies to the electric utility grid, thus causing the unit to meet the EGU cogeneration criteria (*i.e.*, greater than one-third of its potential output capacity and greater than 25 MW). A unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the final EGU NESHAP.

Another rule intersection may occur where one or more coal- or oil-fired EGU(s) share an air pollution control device (APCD) and/or an exhaust stack with one or more similarly-fueled IB unit(s). To demonstrate compliance with two different rules, either the emissions would need to be apportioned to the appropriate source or the more stringent emission limit would need to be met. Data needed to apportion emissions are not currently required by this final rule or the final boiler NESHAP and are not otherwise available. Therefore, the EPA is finalizing the requirement to comply with the more stringent emission limit.

3. CAA Section 129

Clean Air Act section 129 regulates units that combust ''non-hazardous secondary materials,'' as that term is defined by the Administrator under the Resource Conservation and Recovery Act (RCRA), that are ''solid wastes.'' On March 21, 2011, the EPA promulgated the final Non-Hazardous Solid Waste Definition Rule (76 FR 15456). Any EGU that combusts any solid waste as defined in that final rule is a solid waste

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[9] The CT NESHAP regulates HAP emissions from all simple-cycle and combined-cycle stationary CTs producing electricity or steam for any purpose.

incineration unit subject to emissions standards under CAA section 129.

In the Non-Hazardous Solid Waste Definition Rule, the EPA determined that coal refuse from current mining operations is not considered to be a ''solid waste'' if it is not discarded. Coal refuse that is in legacy coal refuse piles is considered a ''solid waste'' because it has been discarded. However, if discarded coal refuse is processed in the same manner as currently mined coal refuse, the coal refuse would not be considered a solid waste but instead would be considered a product fossil fuel. Therefore, the combustion of such material by a combustion unit would not subject that unit to regulation under CAA section 129. Instead, the unit would be subject to this final rule if it meets the definition of EGU. In the proposed rule, we assumed that all units that combust coal refuse and otherwise meet the definition of a coal-fired EGU are in fact combusting newly mined coal refuse or coal refuse from legacy piles that has been processed such that it is not a solid waste. We did not receive any information since proposal that would cause us to revise this determination in the final rule.

Further, CAA section 129(g)(1)(B) exempts from regulation

> ''* * * qualifying small power production facilities, as defined in section 796(17)(C) of Title 16, or qualifying cogeneration facilities, as defined in section 796(18)(B) of Title 16, which burn homogeneous waste * * * for the production of electric energy or in the case of qualifying cogeneration facilities which burn homogeneous waste for the production of electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes * * *''

If the ''homogeneous waste'' material that such facilities combust is also a fossil fuel, and those facilities otherwise meet the definition of an EGU under CAA section 112(a)(8), then those facilities are exempt from regulation under CAA section 129 but covered under this final rule. For example, a qualifying small power production facility or cogeneration facility combusting only coal refuse that is a solid waste and a ''homogenous waste,'' as that term is defined in the final CAA section 129 CISWI standards, would be subject to this final rule if the unit also met the definition of EGU.

D. What are the health effects of pollutants emitted from coal- and oil-fired EGUs?

This final rule protects air quality and promotes public health by reducing emissions of some of the HAP listed in CAA section 112(b)(1). Utilities are by far the largest anthropogenic source of Hg in the U.S. In addition, EGUs are the largest source of HCl, hydrogen fluoride (HF), and selenium (Se) emissions, and a major source of metallic HAP emissions including As, chromium (Cr), Ni, and others. The discrepancy is even greater now that almost all other major source categories have been required to control Hg and other HAP under CAA section 112. In 2005, U.S. EGUs emitted 50 percent of total domestic anthropogenic Hg emissions, 62 percent of total As emissions, 39 percent of total cadmium (Cd) emissions, 22 percent of total Cr emissions, 82 percent of total HCl emissions, 62 percent of total HF emissions, 28 percent of total Ni emissions, and 83 percent of total Se emissions.[10] 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.*, irritation of the lung, skin, and mucus membranes; detrimental effects on the central nervous system; damage to the kidneys; and alimentary effects such as nausea and vomiting). Two of the HAP are classified as human carcinogens (As and CrVI) and two as probable human carcinogens (Cd and Ni). *See* 76 FR 25003–25005 for a fuller discussion of the health effects associated with these pollutants.

III. Appropriate and Necessary Finding

A. Overview

In December 2000, the EPA issued a finding pursuant to CAA section 112(n)(1)(A) that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under section 112(d). The EPA found that it was appropriate to regulate HAP emissions from coal- and oil-fired EGUs because, among other reasons, Hg is a hazard to public health, and U.S. EGUs are the largest domestic source of Hg emissions. The EPA also found it appropriate to regulate HAP emissions from EGUs because it had identified certain control options that would effectively reduce HAP emissions from U.S. EGUs. The EPA found that it was necessary to regulate HAP emissions from U.S. EGUs under section 112 because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from HAP emissions from U.S. EGUs and that CAA section 112 is intended to address HAP emissions. *See* 76 FR 24984–20985 (for further discussion of 2000 finding).

Because several years had passed since the 2000 finding, the EPA performed additional technical analyses for the proposed rule, even though those analyses were not required. These analyses included a national-scale Hg risk assessment focused on populations with high levels of self-caught fish consumption, and a set of 16 case studies of inhalation cancer risks for non-Hg HAP. The analyses confirm that it remains appropriate and necessary to regulate U.S. EGUs under section 112.

In the preamble to the proposed rule, the EPA reported the results of those additional technical analyses. Those analyses confirmed the 2000 finding that it is appropriate to regulate U.S. EGUs under section 112 by demonstrating that (1) Hg continues to pose a hazard to public health because up to 28 percent of watersheds were estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the reference dose for methylmercury (MeHg RfD), a level above which there is increased risk of neurological effects in children, (2) non-Hg HAP emissions pose a hazard to public health because case studies at 16 facilities demonstrated that lifetime cancer risks at 4 of the facilities exceed 1 in 1 million, and (3) U.S. EGUs remain the largest domestic source of Hg emissions and several HAP (*e.g.*, HF, Se, HCl), and are among the largest contributors for other HAP (*e.g.*, As, Cr, Ni, HCN). Thus, in the preamble to the proposed rule, the EPA found that Hg and non-Hg HAP emissions from U.S. EGUs pose hazards to public health, which confirmed the 2000 finding and demonstrated that it remains appropriate to regulate U.S. EGUs under section 112.

In the preamble to the proposed rule, the EPA also found that it is appropriate to regulate U.S. EGUs because (1) Hg emissions pose a hazard to the environment and wildlife, adversely impacting species of fish-eating birds and mammals, (2) acid gas HAP pose a hazard to the environment because they contribute to aquatic acidification, and (3) effective controls are available to reduce Hg and non-Hg HAP emissions from U.S. EGUs.

The additional analyses reported in the preamble to the proposed rule also confirmed that it remains necessary to regulate U.S. EGU under CAA section 112. These analyses demonstrated that (1) Hg emissions from U.S. EGUs remaining in 2016 are reasonably anticipated to pose a hazard to public health after imposition of other CAA

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[10] From 2005 National-Scale Air Toxics Assessment (NATA), available at *http://www.epa.gov/ttn/atw/nata2005/*.

requirements, such as the Cross-State Air Pollution Rule (CSAPR); (2) U.S. EGUs are reasonably anticipated to remain the largest source of Hg in the U.S. and thus contribute to the risk associated with exposure to MeHg; (3) Hg emissions from U.S. EGUs after imposition of the requirements of the CAA were projected to be 29 tons per year in 2016, similar to levels of Hg emitted today, indicating that further substantial reductions in Hg emissions are not reasonably anticipated without federal regulations on Hg from U.S. EGUs; (4) we cannot be certain that the identified cancer risks attributable to non-Hg emissions from U.S. EGUs will be addressed through imposition of the requirements of the CAA because companies can use compliance strategies for criteria pollutants that do not achieve HAP co-benefits (*e.g.*, purchasing allowances in a trading program); and (5) we cannot ensure that Hg and non-Hg HAP emissions reductions achieved since 2005 would be permanent without federally binding regulations for Hg from U.S. EGUs.

Since issuance of the proposed rule, the EPA has conducted peer reviews of the national-scale Hg risk assessment (Hg Risk TSD) and the approach for estimating chromium and nickel inhalation cancer risk in the case studies.[11] [12] The peer review of the Hg Risk TSD was conducted by EPA's independent Science Advisory Board (SAB). The SAB stated that it ''supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs.'' [13] SAB recommended several improvements to the data, methods and documentation of the analyses, which EPA has fully addressed in the revised Hg Risk TSD.

As described in the revised Hg Risk TSD, after addressing comments from the peer review, the revised results show that up to 29 percent of modeled watersheds are estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the MeHg RfD, an increase of one percentage point from the results reported in the proposed rule. We conclude that Hg emissions from EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds at risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone without considering deposition from other sources would lead to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition.[14] [15] Each of these results independently supports our conclusion that Hg emissions from EGUs pose hazards to public health.

The peer review of the approach to estimate Ni and Cr cancer risk in the case studies also supported EPA's assessment. The EPA enhanced this analysis in response to the peer review and public comments. The results of those revised analyses show that 6 of 16 modeled facilities have lifetime cancer risks greater than 1 in a million, thus confirming that non-Hg HAP emissions from U.S. EGUs remain a hazard to public health. Given Congress' determination that categories of sources that emit HAP resulting in a lifetime cancer risk greater than 1 in a million should not be removed from the CAA section 112(c) source category list and should continue to be regulated under CAA section 112, the EPA concludes that risk above that level represents a hazard to public health.

Based on our consideration of the peer reviews, public comments, and our updated analyses, we confirm the findings that Hg and non-Hg HAP emissions from U.S. EGUs pose hazards to public health and that it remains appropriate to regulate U.S. EGUs under CAA section 112. We also conclude that it remains appropriate to regulate U.S. EGUs under CAA section 112 because of the magnitude of Hg and non-Hg emissions, environmental effects of Hg and certain non-Hg emissions, and the availability of controls to reduce HAP emissions from EGUs.

In addition, we conclude that the hazards to public health from Hg and non-Hg emissions from U.S. EGUs are reasonably anticipated to remain after imposition of the requirements of the CAA. The same is true for hazards to the environment. Thus, we confirm that it is necessary to regulate U.S. EGUs under CAA section 112.

B. Peer Review of the Hg Risk TSD Supporting the Appropriate and Necessary Finding for Coal and Oil-Fired EGUs and EPA Response

In the preamble to the proposed rule, the EPA stated that ''in making the finding that it remains appropriate and necessary to regulate EGUs to address public health and environmental hazards associated with emissions of Hg and Non-Hg HAP from EGUs, the EPA determined that the Hg Risk TSD supporting EPA's 2011 review of U.S. EGU health impacts should be peer-reviewed.'' [16] We also indicated that due to the court-ordered schedule for the final rule, we planned to conduct the peer review as expeditiously as possible after issuance of the proposed rule, and that the results of the peer review and any EPA response would be published before the final rule. Due to the extension of the public comment period and the volume of public comments received on the analyses supporting the proposed rule, we were unable to publish EPA's response prior to signature of the final rule.

The EPA's response to the peer review the Hg Risk TSD is fully documented in the revised *Technical Support Document (TSD): National-Scale Assessment of Hg Risk to Populations of High Consumption of Self-Caught Fish In Support of the Appropriate and Necessary Finding for Coal and Oil-Fired Electric Generating Units.*[17] The following sections describe the peer review process that we followed, provide the peer review charge questions presented to the peer review panel, summarize the key recommendations from the peer review, and summarize our responses to those recommendations.

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[11] U.S. EPA. 2011a. *National-Scale Assessment of Mercury Risk to Populations with High Consumption of Self-caught Freshwater Fish In Support of the Appropriate and Necessary Finding for Coal- and Oil-Fired Electric Generating Units.* Office of Air Quality Planning and Standards. November. EPA–452/R–11–009.

[12] U.S. EPA. 2011b. *Supplement to Non-mercury Case Study Chronic Inhalation Risk Assessment for the Utility MACT Appropriate and Necessary Analysis.* Office of Air Quality Planning and Standards. November.

[13] U.S. Environmental Protection Agency-Science Advisory Board (U.S. EPA–SAB). 2011. Peer Review of EPA's Draft National-Scale Mercury Risk Assessment. EPA–SAB–11–017. September. Available on the Internet at *http://yosemite.epa.gov/sab/sabproduct.nsf/BCA23C5B7917F5BF8525791A0072CCA1/$File/EPA-SAB-11-017-unsigned.pdf.*

[14] Because some watersheds with exposures sufficient to exceed the RfD with Hg deposition from U.S. EGUs alone without considering deposition from other sources also have U.S. EGU contributions of more than 5 percent of total Hg deposition, there is some overlap between the two risk metrics. This explains why the total percent of watersheds exceeding either risk metric is less than the sum of the individual risk metrics.

[15] Requiring at least a 5 percent EGU contribution is a conservative approach given the increasing risks associated with incremental exposures above the RfD. Because we are finding 24 percent of watersheds with populations potentially at risk even using this conservative approach, we have confidence that emissions of Hg from U.S. EGUs are causing a hazard to public health.

[16] 76 FR 25012.

[17] U.S. EPA, 2011a.

1. Summary of Peer Review Process

Peer review is consistent with EPA's open and transparent process to ensure that the Agency's scientific assessments and rulemakings are based on the best science available. This regulatory action was supported by the Hg Risk TSD, which is a highly influential scientific assessment. Therefore, the EPA conducted a peer review in accordance with OMB's *Final Information Quality Bulletin for Peer Review*[18] as described below. All the materials related to the peer review, including the SAB's final report, can be found in the docket for this rulemaking.

The EPA commissioned the peer review through EPA's SAB, which provides independent advice and peer review to EPA's Administrator on the scientific and technical aspects of environmental issues. The SAB convened a 22-member peer review committee. The SAB process for selecting the panel began with two **Federal Register** Notices requesting nominations for the *Mercury Review Panel.*[19] Based on nominations received, a list of potential panel members, along with bio-sketches, was posted for public comment on the SAB Web site on April 15, 2011. The members of the *Mercury Review Panel* were announced on May 24, 2011. The membership of the panel included representatives of 16 academic institutions, 4 state health or environmental agencies, 1 federal agency, and 1 utility industry organization.[20] The panel held a public meeting in Research Triangle Park, NC, on June 15–17, 2011, which included the opportunity for public comment on the Hg Risk TSD and the peer review process.[21] At the June 15–17 public meeting, the panel completed a draft peer review report. The minutes of that meeting and the draft peer review report were posted to the SAB public Web site within the public comment period for the proposed rule. The panel discussed the draft report at a public teleconference on July 12, 2011, during which additional opportunities for public comment were provided,[22] and submitted a revised draft for quality review by the Chartered SAB before the end of the public comment period on the rule. The Chartered SAB held a public teleconference on September 7, 2011, to conduct a quality review of the draft report; this teleconference also included a final opportunity for public comment.[23] The SAB submitted its final report to EPA on September 29, 2011.[24] Notice of all the meetings was published in the **Federal Register** and all of the materials discussed at the SAB meetings, including technical documents, presentations, meeting minutes, and draft reports were posted for public access on the SAB Web site[25] and were added to the docket for the final rule on October 14, 2011.

2. Peer Review Charge Questions

The EPA asked the SAB to comment on the Hg Risk TSD, including the overall design and approach and the use of specific models and key assumptions. The EPA also asked the SAB to comment on the extent to which specific facets of the assessment were well characterized in the Hg Risk TSD. The specific charge questions are listed below:

Question 1. Please comment on the scientific credibility of the overall design of the mercury risk assessment as an approach to characterize human health exposure and risk associated with U.S. EGU mercury emissions (with a focus on those more highly exposed).

Question 2. Are there any additional critical health endpoint(s) besides IQ loss, which could be quantitatively estimated with a reasonable degree of confidence to supplement the mercury risk assessment (*see* section 1.2 of the Mercury Risk TSD for an overview of the risk metrics used in the risk assessment)?

Question 3. Please comment on the benchmark used for identifying a potentially significant public health impact in the context of interpreting the IQ loss risk metric (i.e., an IQ loss of 1 to 2 points or more representing a potential public health hazard). Is there any scientifically credible alternate decrement in IQ that should be considered as a benchmark to guide interpretation of the IQ risk estimates (*see* section 1.2 of the Mercury Risk TSD for additional detail on the benchmark used for interpreting the IQ loss estimates)?

Question 4: Please comment on the spatial scale used in defining watersheds that formed the basis for risk estimates generated for the analysis (i.e., use of 12-digit hydrologic unit code classification). To what extent do [Hydrologic Unit Code] HUC12 watersheds capture the appropriate level of spatial resolution in the relationship between changes in mercury deposition and changes in MeHg fish tissue levels? (see section 1.3 and Appendix A of the Mercury Risk TSD for additional detail on specifying the spatial scale of watersheds used in the analysis).

Question 5: Please comment on the extent to which the fish tissue data used as the basis for the risk assessment are appropriate and sufficient given the goals of the analysis. Please comment on the extent to which focusing on data from the period after 1999 increases confidence that the fish tissue data used are more likely to reflect more contemporaneous patterns of Hg deposition and less likely to reflect earlier patterns of Hg deposition. Are there any additional sources of fish tissue MeHg data that would be appropriate for inclusion in the risk assessment?

Question 6: Given the stated goal of estimating potential risks to highly exposed populations, please comment on the use of the 75th percentile fish tissue MeHg value (reflecting targeting of larger but not the largest fish for subsistence consumption) as the basis for estimating risk at each watershed. Are there scientifically credible alternatives to use of the 75th percentile in representing potential population exposures at the watershed level?

Question 7: Please comment on the extent to which characterization of consumption rates and the potential location for fishing activity for high-end self-caught fish consuming populations modeled in the analysis are supported by the available study data cited in the Mercury Risk TSD. In addition, please comment on the extent to which consumption rates documented in Section 1.3 and in Appendix C of the Mercury Risk TSD provide appropriate representation of high-end fish consumption by the subsistence population scenarios used in modeling exposures and risk. Are there additional data on consumption behavior in subsistence populations active at inland freshwater water bodies within the continental U.S.?

Question 8: Please comment on the approach used in the risk assessment of

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[18] Office of Management and Budget (OMB). 2004. *Final Information Quality Bulletin for Peer Review.* December. Available on the Internet at *http://www.whitehouse.gov/omb/memoranda_fy2005_m05-03.*

[19] 76 FR 10896 and 76 FR 17649. The first notice requested nominations to a Clean Air Scientific Advisory Committee (CASAC) panel. Upon review of the scope of the CASAC charter (resulting from a public comment received in response to the first notice), the SAB determined that it would be more appropriate to form a panel under the SAB, rather than CASAC. The second notice announced this change and requested nominations for the SAB panel.

[20] The full list of panel members is documented at *http://yosemite.epa.gov/sab/sabproduct.nsf/0/9F048172004D93BB8525783900503486/$File/Determination%20memo%20with%20addendum-05.24.11.pdf.*

[21] 76 FR 29746.

[22] 76 FR 39102.

[23] 76 FR 50729.

[24] U.S. EPA–SAB, 2011. Peer Review of EPA's Draft National-Scale Mercury Risk Assessment.

[25] *See http://yosemite.epa.gov/sab/sabpeople.nsf/WebCommittees/BOARD.*

assuming that a high-end fish consuming population could be active at a watershed if the ''source population'' for that fishing population is associated with that watershed (e.g., at least 25 individuals of that population are present in a U.S. Census tract intersecting that watershed). Please identify any additional alternative approaches for identifying the potential for population exposures in watersheds and the strengths and limitations associated with these alternative approaches (additional detail on how EPA assessed where specific high-consuming fisher populations might be active is provided in section 1.3 and Appendix C of the Mercury Risk TSD).

Question 9: Please comment on the draft risk assessment's characterization of the limitations and uncertainty associated with application of the Mercury Maps approach (including the assumption of proportionality between changes in mercury deposition over watersheds and associated changes in fish tissue MeHg levels) in the risk assessment. Please comment on how the output of CMAQ [Community Multiscale Air Quality] modeling has been integrated into the analysis to estimate changes in fish tissue MeHg levels and in the exposures and risks associated with the EGU-related fish tissue MeHg fraction (*e.g.,* matching of spatial and temporal resolution between CMAQ modeling and HUC12 watersheds). Given the national scale of the analysis, are there recommended alternatives to the Mercury Maps approach that could have been used to link modeled estimates of mercury deposition to monitored MeHg fish tissue levels for all the watersheds evaluated? (additional detail on the Mercury Maps approach and its application in the risk assessment is presented in section 1.3 and Appendix E of the Mercury Risk TSD).

Question 10: Please comment on the EPA's approach of excluding watersheds with significant non-air loadings of mercury as a method to reduce uncertainty associated with application of the Mercury Maps approach. Are there additional criteria that should be considered in including or excluding watersheds?

Question 11: Please comment on the specification of the concentration-response function used in modeling IQ loss. Please comment on whether EPA, as part of uncertainty characterization, should consider alternative concentration-response functions in addition to the model used in the risk assessment. Please comment on the extent to which available data and methods support a quantitative treatment of the potential masking effect of fish nutrients (*e.g.,* omega-3 fatty acids and selenium) on the adverse neurological effects associated with mercury exposure, including IQ loss (detail on the concentration-response function used in modeling IQ loss can be found in section 1.3 of the Mercury Risk TSD).

Question 12: Please comment on the degree to which key sources of uncertainty and variability associated with the risk assessment have been identified and the degree to which they are sufficiently characterized.

Question 13: Please comment on the draft Mercury Risk TSD's discussion of analytical results for each component of the analysis. For each of the components below, please comment on the extent to which EPA's observations are supported by the analytical results presented and whether there is a sufficient characterization of uncertainty, variability, and data limitations, taking into account the models and data used: Mercury deposition from U.S. EGUs, fish tissue MeHg concentrations, patterns of Hg deposition with HG fish tissue data, percentile risk estimates, and number and frequency of watersheds with populations potentially at risk due to U.S. EGU mercury emissions.

Question 14: Please comment on the degree to which the final summary of key observations in Section 2.8 is supported by the analytical results presented. In addition, please comment on the degree to which the level of confidence and precision in the overall analysis is sufficient to support use of the risk characterization framework described on page 18.

3. Summary of Peer Review Findings and Recommendations

The SAB was generally supportive of EPA's approach.[26] The SAB concluded, ''[i]n summary, based on its review of the draft Technical Support Document and additional information provided by EPA representatives during the public meetings, the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs.'' [27] The SAB further concluded, ''[t]he SAB regards the design of the risk assessment as suitable for its intended purpose, to inform decision-making regarding an 'appropriate and necessary finding' for regulation of hazardous air pollutants from coal and oil-fired EGUs, provided that our recommendations are fully considered in the revision of the assessment.'' [28]

The SAB report contained many recommendations for improving the Hg Risk TSD, which the SAB organized into three general themes: (1) Improve the clarity of the Hg Risk TSD regarding methods and presentation of results, (2) expand the discussion of sources of variability and uncertainty, and (3) de-emphasize IQ loss as an endpoint. In the following subsection, we provide EPA's response to these recommendations.

4. The EPA's Responses to Peer Review Recommendations

In response to the peer review, the EPA has substantially revised the Hg Risk TSD. The revised Hg Risk TSD addresses all of the recommendations from the SAB and includes a detailed list of the specific revisions made to the Hg Risk TSD. Revisions in response to the main recommendations are summarized below. Italicized statements are the SAB's recommendations, which are followed by EPA's response.

- *The watershed-focus of the Hg Risk TSD should be clearly stated early in the introduction to the document.* We have stated clearly in the introduction to the revised Hg Risk TSD that the focus of the analysis is on scenarios of high fish consumption by subsistence level fishing populations, assessed at watersheds where there is the potential for such subsistence fishing activity. Specifically, we modeled risk for a set of subsistence fisher scenarios at those watersheds where (a) we have measured fish tissue Hg data and (b) it is reasonable to assume that subsistence-level fishing activity could occur. We emphasize the point that the analysis is not a representative population-weighted assessment of risk. Rather, it is based on evaluating these potential exposure scenarios.
- *Because IQ does not fully capture the range of neurodevelopmental effects associated with Hg exposure, analysis of this endpoint should be deemphasized (and moved to an appendix) and primary focus should be placed on the MeHg RfD-based hazard quotient metric.* We modified the structure of the revised Hg Risk TSD accordingly.
- *Clarify the rationale for using a Hazard Quotient (HQ) at or above 1.5 as the basis for selecting potentially impacted watersheds.* The SAB fully supported using HQ as the risk metric, but we revised the discussion in the Hg Risk TSD to clarify why we selected 1.5

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[26] U.S. EPA–SAB, 2011.

[27] *Id.*

[28] *Id.*

as the benchmark. We clarified that exposures above the RfD (*i.e.,* an HQ above one) represent increasing risk of neurological health effects.[29] We further clarified that the HQ is calculated to only one significant digit, based on the precision in the underlying RfD calculations. As a result, rounding convention requires that any values at or above 1.5 be expressed as an HQ of 2, while any values below 1.5 (*e.g.,* 1.49) be rounded to an HQ of 1. Thus, MeHg exposures leading to an HQ at or above 1.5 for pregnant women are considered above the RfD and are associated with increased risk of neurological health effects in children born to those mothers.

- *Regarding the fish tissue dataset used in the Hg Risk TSD, clarify which species of Hg is reflected in the underlying samples and discuss the implications of differences across states in sampling protocols in introducing bias into the analysis.* We clarified that in most cases, the fish tissue is measured for total Hg. Furthermore, based on the scientific literature,[30] it is reasonable to assume that more than 90 percent of fish tissue Hg is MeHg. Therefore, we incorporated an Hg conversion factor[31] into our exposure calculations to account for the fraction of total Hg that is MeHg in fish. We also expanded the discussion of uncertainty to address the potential for different sampling protocols across states to introduce bias into the Hg Risk TSD.
- *Additional detail should be provided on the characteristics of the fish tissue Hg dataset, including its derivation and the distribution of specific attributes across the dataset (e.g., number of fish tissue samples and number of different waterbodies in a watershed, number of species reflected across watersheds).* We included additional figures and tables describing the derivation of the watershed-level fish tissue Hg dataset, including the filtering steps applied to the original water body level data and the additional steps taken to generate the watershed-level fish tissue Hg percentile estimates. In addition, we included tables summarizing key attributes of the dataset (*e.g.,* distribution of fish tissue sample size and number of species across the watershed-level estimates).
- *Determine whether there is additional (more recent) fish tissue data for key states including Pennsylvania, New Jersey, Kentucky and Illinois where U.S. EGUs Hg deposition may be more significant.* We expanded the fish tissue dataset by incorporating additional fish tissue data from the National Listing of Fish Advisories (NLFA), which included additional data for four states (MI, NJ, PA, and MN). We also obtained additional data for Wisconsin. These additional data expanded the number of watersheds in the analysis from 2,317 to 3,141, an increase of 36 percent. The additional watersheds improve coverage in areas with high levels of U.S. EGU-attributable Hg deposition, and thus increase our confidence in the overall results of the Hg Risk TSD.
- *Include additional discussion of the potential that the low sampling rates reflected across many of the watersheds may low-bias the 75th percentile fish tissue Hg estimates used in estimating potential exposures. In addition, include a sensitivity analysis using the 50th percentile estimates to provide a bound on the risk.* The SAB expressed support for the use of the 75th percentile fish tissue Hg value in the Hg Risk TSD, while recommending additional discussion of the issue. We provided additional description of the fish tissue dataset, including distribution of sample sizes and fish species across the watersheds, and an improved discussion of uncertainty and potential low bias resulting from estimation of the 75th percentile fish tissue levels. We also included a sensitivity analysis that used the 50th percentile watershed-level fish tissue Hg level. This sensitivity analysis showed that using the 50th percentile estimates resulted in a decrease in the number and percentage of modeled watersheds with populations potentially at-risk from U.S. EGU-attributable MeHg exposures, from 29 percent of watersheds exceeding either risk metric (*i.e.,* MeHg exposure from U.S. EGUs alone exceeds the RfD or total MeHg exposure exceeds the RfD and U.S. EGUs contribute at least 5 percent) in the revised Hg Risk TSD to 26 percent in the sensitivity analysis in the revised Hg Risk TSD.
- *Expand the discussion of caveats associated with the fish consumption rates used in the analysis.* The SAB was generally supportive of the consumption rates used, while recommending additional discussion of caveats. We expanded the discussion of uncertainty related to the fish consumption rates to address the caveats identified by the SAB. The uncertainty discussion now explains (1) that high-end consumption rates for South Carolina reflect small sample sizes, and therefore may be more uncertain, (2) that the consumption surveys underlying the studies are older (*i.e.,* mostly based on survey data from the 1990s) and behavior may have changed (*i.e.,* consumption rates may have changed since the surveys were conducted), and (3) that consumption rates used in the Hg Risk TSD are annualized rather than seasonal rates and thus contribute little to overall uncertainty. None of these sources of uncertainty is associated with a particular directional bias (*e.g.,* neither systematically higher nor lower risk).
- *Verify whether the consumption rates are daily values expressed as annual averages and whether they are ''as caught'' or ''as prepared.''* We carefully reviewed the studies underlying the fish consumption rates used in the Hg Risk TSD and verified that the rates are annual averages of the daily consumption rates and that they represent as prepared estimates. We also expanded the explanation of the exposure calculations to describe more completely the exposure factors and equation used to generate the average daily MeHg intake estimates for the subsistence scenarios.
- *Explain the criteria for exclusion of fish less than 7 inches in length from analysis.* We provided the rationale for the 7-inch cutoff for edible fish used in the Hg Risk TSD. Seven inches represents a minimum size limit for a number of key edible freshwater fish species established at the state level. For example, Pennsylvania establishes 7 inches as the minimum size limit for both trout and salmon (other edible fish species such as bass, walleye and northern pike have higher minimum size limits). The impact of the 7-inch cutoff is likely to be quite small, as only 6 percent of potential fish samples were excluded due to this criterion.
- *Identify the number of watersheds excluded from the analysis due to the criterion for excluding watersheds with less than 25 members of a source population.* The SAB was generally supportive of the approach used for identifying watersheds with the potential for subsistence activity, while recommending additional information on the results of applying the approach. We added a figure to illustrate the number of watersheds with fish tissue Hg data used to model risk for each of the subsistence fishing scenarios. For all scenarios except the female subsistence fishing scenario, the exposure scenarios significantly limited the number of

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[29] As stated in the preamble to the proposal, based on the current literature, exposures above the RfD contribute to risk of adverse effects.

[30] See the literature summary in Chapter 4 of U.S. EPA. 2000. *Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories.* Office of Science and Technology, Office of Water, Washington, DC EPA 823–B–00–007.

[31] In the Hg Risk TSD accompanying the proposed rule, we assumed that 100 percent of Hg in fish was MeHg. We derived the 0.95 conversion factor for the revised Hg Risk TSD to reflect that most studies show that more than 90 percent of total Hg in fish is MeHg. See Chapter 4 of U.S. EPA, 2000.

watersheds. Because the female subsistence fishing scenario does not differentiate with regard to ethnicity or socio-economic status (SES), we applied this scenario to all regions of the country and to all watersheds with fish tissue Hg data. This reflects our assumption that, given the generalized nature of the female subsistence fishing scenario, it is reasonable to assume that it could potentially occur at any watershed with fish tissue Hg data. The female subsistence fishing scenario included in the revised risk assessment is similar to the high-consuming female scenario included in the Hg Risk TSD.[32] However, the female subsistence fishing scenario is applied to all watersheds, while in the scenario for the high-consuming low-income female angler, we only evaluated watersheds with a population of at least 25 low-income females. The female subsistence fishing scenario provides greater coverage geographically than the high-consuming low-income female scenario. As described in the revised Hg Risk TSD, the EPA made this change in response to SAB's concerns regarding the potential exclusion of watersheds with fewer than 25 individuals and regarding coverage for high-end recreational fish consumption.[33]

- *Enhance the discussion of the assumption of a linear relationship between changes in Hg deposition and changes in fish tissue Hg at the watershed level, including providing citations to more recent studies supporting the proportional relationship between changes in Hg deposition and changes in MeHg fish tissue levels.* The SAB supported the assumption of a linear relationship between changes in Hg deposition and changes in fish tissue Hg at the watershed level, while recommending additional supporting language. We expanded our discussion of the scientific basis for the proportionality assumption and added citations for the more recent studies supporting the assumption. We also expanded the discussion of uncertainties associated with this assumption, including uncertainties related to the potential for sampled fish tissue Hg level to reflect previous Hg deposition, and the potential for non-air sources of Hg to contribute to sampled fish tissue Hg levels. Each of these sources of uncertainty may result in potential bias in the estimate of exposure associated with current deposition. If the fish tissue Hg levels are too high due to either previous Hg deposition or non-air sources of Hg, then the absolute level of exposure attributed to both total Hg deposition and U.S. EGU-attributable Hg deposition will be biased high. However, the percent contribution from U.S. EGUs will not be affected as it depends entirely on deposition. The EPA took steps to minimize the potential for these biases by (1) only using fish tissue Hg samples from after 1999, and (2) screening out watersheds that either contained active gold mines or had other substantial non-U.S. EGU anthropogenic emissions of Hg. The SAB concluded that the EPA's approach to minimizing the potential for these biases to affect the results of the Hg Risk TSD is sound. In addition, we conducted several sensitivity analyses to gauge the impact of excluding watersheds with the potential for non-EGU Hg loading. We found that the estimates of the percent of modeled watersheds with populations potentially at-risk were largely insensitive to these exclusions, suggesting that any potential biases from including watersheds with potential non-air Hg loadings are likely to be small.

- *Additional sources of variability should be discussed in terms of the degree to which they are reflected in the design of the risk assessment and the impact that they might have on risk estimates. These include: (1) The geographic patterns of populations of subsistence fishers, including how this factor interacts with the limited coverage we have for watersheds with our fish tissue Hg data, (2) the protocols used by states in collecting fish tissue Hg data, (3) body weights for subsistence fishing populations and the impact that this might have on exposure estimates, and (4) preparation and cooking methods which affect the conversion of fish tissue Hg levels (as measured) into "as consumed" values.* We expanded the discussion of sources of variability in the revised Hg Risk TSD to more fully address these sources of variability. The Hg Risk TSD quantitatively reflected many aspects of variability, including spatial and temporal variability in Hg emissions, Hg deposition, fish tissue Hg levels, and subsistence behavior. After evaluating the aspects of variability assessed qualitatively in the Hg Risk TSD such as temporal response in fish tissue, we do not believe that quantitatively incorporating any of these aspects would substantially change the risk results given the stated goal of the analysis to identify watersheds where potential exposures to MeHg from self-caught fish consumption could exceed the RfD.

- *Additional sources of uncertainty should be discussed in terms of their potential impact on risk estimates. These include: (1) Emissions inventory used in projecting total and U.S. EGU-attributable Hg deposition, including the projection of reductions in U.S. EGU emissions for the 2016 scenario, (2) air quality modeling with CMAQ including the prediction of future air quality scenarios, (3) ability of the Mercury Maps-based approach for relating Hg deposition to MeHg in fish to capture Hg hotspots, (4) the limited coverage that we have with fish tissue Hg data for watersheds in the U.S. and implications for the Hg Risk TSD, (5) the preparation factor used to estimate "as consumed" fish tissue Hg levels, (6) the proportionality assumption used to relate changes in Hg deposition to changes in fish tissue Hg levels at the watershed-level, (7) characterization of the spatial location of subsistence fisher populations (including the degree to which these provide coverage for high-consuming recreational fishers), and (8) application of the RfD to low SES populations and concerns that this could low-bias the risk estimates.* We expanded the discussion of sources of uncertainty presented in the revised TSD to address more fully these sources of uncertainty and the potential impact on risk estimates. Regarding these eight additional sources of uncertainty, we have (1) evaluated the uncertainties in the emissions and determined that while an important source of uncertainty, we are not able to quantify emissions uncertainty in the risk analysis, but have determined that the emissions inventories and emissions models represent the best available methods for predicting Hg emissions in the U.S., (2) evaluated the uncertainties in the Hg deposition predictions and determined that while an important source of uncertainty, we are not able to quantify uncertainty in Hg deposition in the Hg Risk TSD. Moreover, the CMAQ model used to estimate deposition is based on peer reviewed science and represents the best available method for predicting Hg deposition in the U.S., (3) evaluated the ability of the Mercury Maps-based approach for relating Hg deposition to MeHg in fish to capture Hg hotspots and determined that while finer resolution deposition modeling might reveal additional areas with elevated deposition, the 12 kilometer

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[32] In the Revised Hg Risk TSD, this population is also referred to as the "typical female subsistence consumer."

[33] This change led to a very small increase in the number of watersheds with populations potentially at-risk. In the Hg Risk TSD accompanying the proposed rule, approximately 4 percent of modeled watersheds were excluded based on the SES-based filtering criteria.

(km) deposition modeling matches well with the watershed size selected for the analysis, and thus the use of 12 km deposition estimates with the Mercury Maps based approach will not be a large source of uncertainty, (4) evaluated the limited coverage that we have with fish tissue Hg data for watersheds in the U.S. and implications for the Hg Risk TSD and based on the SAB's recommendations, we supplemented the coverage of watersheds by obtaining additional fish tissue Hg samples for areas heavily impacted by U.S. EGU deposition, thus reducing the uncertainty in the analysis, (5) evaluated the uncertainty in the preparation factor and determined that the level of uncertainty is low, and as such would have minimal impact on the risk estimates, (6) evaluated the uncertainty resulting from the proportionality assumption used to relate changes in Hg deposition to changes in fish tissue Hg levels at the watershed-level, and determined, based both on quantitative sensitivity analyses and qualitative assessments, that this source of uncertainty is not likely to greatly influence the results, and is not likely to have a specific directional bias, (7) evaluated the uncertainty related to characterization of the spatial locations of subsistence populations and determined that uncertainty could be reduced by focusing the risk estimates on female subsistence fishing populations, which are assumed to have the potential to fish in all watersheds, in response to SAB's concerns regarding potential exclusion of watersheds with fewer than 25 individuals and (8) evaluated the potential impact of the uncertainty in application of the RfD to low SES populations. The EPA determined that due to the method used in calculating the RfD, we have confidence that the RfD provides protection for low SES populations.

- *Expand the sensitivity analyses (over those included in the original risk assessment) to address uncertainty related to the use of the 75th percentile fish tissue Hg value (at each watershed) as the core risk estimate.* Based on the SAB's recommendation, we added a sensitivity analysis using the median fish tissue Hg estimate (at the watershed level). This sensitivity analysis showed that use of the median fish tissue Hg concentration instead of the 75th percentile resulted in a relatively small decrease (*i.e.,* 10 percent) in the estimates of watersheds with populations potentially at-risk, and did not substantially change the conclusions of the risk assessment.

C. Summary of Results of Revised Hg Risk TSD of Risks to Populations With High Levels of Self-Caught Fish Consumption

Based on the recommendations we received from the SAB, we revised the quantitative analysis of risk to subsistence fishing populations with high levels of fish consumption. Our revision to the quantitative risk results reflects three key recommendations from the SAB, including (1) addition of 824 watersheds based on additional fish tissue Hg sample data we obtained from states and the National Listing of Fish Advisories, (2) application of a 0.95 adjustment factor to the reported fish tissue Hg concentrations to account for the fraction that is MeHg, and (3) inclusion of all watersheds with fish samples that meet the filtering criteria [34] in representing potential exposures associated with increased risk of neurologic health effects for female subsistence fishing populations.

Based on these revisions, our estimates of the number and percent of modeled watersheds with populations potentially at-risk from exposure to EGU-attributable MeHg changed from those presented in the preamble to the proposed rule.[35] For the 99th percentile consumption scenario, the number of watersheds with fish tissue Hg samples where subsistence fishing populations may be at-risk from exposure to EGU-attributable MeHg increased from 672 to 917 (an increase of 36 percent). For this same scenario, the total percent of modeled watersheds with populations potentially at-risk from either risk metric (*i.e.,* MeHg exposure from U.S. EGUs alone exceeds the RfD or total MeHg exposure exceeds the RfD and U.S. EGUs contribute at least 5 percent) increased from 28 percent estimated at proposal to 29 percent after addressing SAB recommendations. The increase in the total percent of modeled watersheds with populations potentially at-risk using the expanded geographic coverage of watersheds provides additional confidence that emissions of Hg from U.S. EGUs pose a hazard to public health. For the 99th percentile consumption scenario, the percent of modeled watersheds with populations potentially at-risk from total potential exposures to MeHg that exceed the RfD and U.S. EGUs contribute at least 5 percent increased from 22 percent to 24 percent. For the 99th percentile consumption scenario, the percent of modeled watersheds with populations potentially at-risk based on Hg deposition from U.S. EGUs alone decreased from 12 percent to 10 percent.

The additional sensitivity analyses conducted in response to the SAB peer review showed that the estimates of the percent of modeled watersheds with populations potentially at-risk are robust to alternative assumptions about both the watersheds included in the analysis and the selection of the 50th percentile or 75th percentile fish tissue Hg level. Sensitivity analyses excluding entire states with the potential for historical loadings of Hg from non-air sources [36] resulted in an increase from 29 percent to 33 percent in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric (*i.e.,* U.S. EGUs alone or total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent). Including only watersheds in the top 25th percentile of U.S. EGU deposition resulted in an increase in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric, from 29 percent to 30 percent. Using the 50th percentile fish tissue Hg level resulted in a decrease in the total percent of modeled watersheds with populations potentially at-risk exceeding either risk metric, from 29 percent to 26 percent. On balance, these sensitivity analyses do not substantially reduce the percent of modeled watersheds with populations potentially at-risk, and thus confirm the finding that Hg emissions from U.S. EGUs pose a hazard to public health. In fact, given the broader coverage of modeled watersheds in the revised analysis, we have even greater confidence in our finding that Hg

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[34] The watersheds were filtered to exclude watersheds that: (a) Were not freshwater, (b) did not have fish sampling data since 2000, (c) did not have fish larger than 7 inches in length, (d) contained active gold mines or (e) had substantial non-air Hg loading.

[35] Since the time of the analyses conducted in support of the proposed rule, the EPA updated IPM modeling to reflect the most recently available information, including public comments and the final CSAPR (see IPM Documentation for further details on these updates, which is available in the docket). Compared to the modeling conducted at proposal, these updates are projected to result in greater reductions in criteria pollutants, and also to have a slightly greater impact on U.S. EGU Hg emissions. Based on the revised projection for 2016, the EPA estimates that U.S. EGUs would emit 27 tons of Hg, as compared to the 29 tons we modeled for the Hg Risk TSD. We do not expect this 2 ton difference to substantially change the mercury risks reported in the preamble to the proposed rule, as this represents less than a 10 percent reduction in Hg emissions.

[36] The SAB noted that areas with substantially elevated fish tissue Hg levels could also be characterized by lakes and rivers with high natural methylation rates, and thus some of the states we excluded for this sensitivity analysis might not have fish tissue Hg levels that reflect non-U.S. EGU Hg loadings.

emissions from U.S. EGUs pose a hazard to public health.

D. Peer Review of the Approach for Estimating Cancer Risks Associated With Cr and Ni Emissions in the U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP and EPA Response

As explained in the preamble to the proposed rule, the EPA submitted for peer review its characterization of the chemical speciation for the emissions of Cr and Ni used in the non-Hg HAP inhalation risk case studies. The remaining aspects of the non-Hg HAP case study risk assessments used methods that were previously peer reviewed. Specifically, the methodologies used to conduct the non-Hg case studies are consistent with those used to conduct inhalation risk assessments under EPA's Risk and Technology Review (RTR) program. Because the RTR assessments are considered to be highly influential science assessments, the methodologies used to conduct them were subject to a peer review by the SAB in 2009. The SAB issued its peer review report in May 2010.[37] The report endorsed the risk assessment methodologies used in the program, and made a number of technical recommendations for EPA to consider as the RTR program evolves.

The EPA's case studies identified Cr and Ni emissions as the key drivers of the estimated inhalation cancer risks for EGUs. Because these results hinged on specific scientific interpretations of data used to characterize EGU emissions of Cr and Ni, the EPA conducted a letter peer review of its analysis and interpretation of those data relative to the quantification of inhalation risks associated with Cr and Ni emissions from U.S. EGUs. The following sections describe the peer review process, enumerate the peer review charge questions presented to the peer review panel, summarize the key recommendations from the peer review, and summarize our responses to those recommendations.

1. Summary of Peer Review Process

The EPA asked three independent, external peer reviewers representing government, academic and the private sector to review of the methods for developing inhalation cancer risk estimates associated with emissions of Cr and Ni compounds from coal- and oil-fired EGUs in support of the appropriate and necessary finding. The approaches and rationale for the technical and scientific considerations used to derive inhalation cancer risks were summarized in the draft document entitled, ''Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds.'' The peer reviewers received several charge questions (three questions on Cr and two questions on Ni, which are provided below) on the technical and scientific relevance of the approaches used to develop the inhalation unit risk estimates. The EPA also provided information on Cr speciation profiles for different industrial sources, as well as information on the Ni speciation of PM from oil-fired EGUs.

2. Peer Review Charge Questions

Below, we present the charge questions posed to the peer reviewers to help guide their review and development of recommendations to EPA on key issues relevant to the characterization of risks from EGU emissions containing either Cr or Ni compounds.

The EPA asked three questions regarding Cr and Cr compounds:

Question 1: Do EPA's judgments related to speciated Cr emissions adequately take into account the available Cr speciation data?

Question 2: Has EPA selected the species of Cr (*i.e.,* hexavalent Cr, Cr(VI)) that accurately represents the toxicity of Cr and Cr compounds?

Question 3: Are the assumptions used in past analysis scientifically defensible, and are there alternatives that EPA should consider for future analysis?

The EPA asked two questions regarding Ni and Ni compounds:

Question 1: Do EPA's judgments related to speciated Ni emissions adequately take into account available speciation data, including recent industry spectrometry studies?

Question 2: Based on the speciation information available and on what we know about the health effects of Ni and Ni compounds, and taking into account the existing Unit Risk Estimates (URE) values (*i.e.,* values derived for EPA's Integrated Risk Information System (IRIS), California Environmental Protection Agency (Cal EPA) and Texas Commission on Environmental Quality (TCEQ)), the EPA has provided several approaches[38] to derive unit risk estimates that may be more scientifically defensible than those used in past analyses. Which of the options presented would result in more accurate and defensible characterization of risks from exposure to Ni and Ni compounds? Are there alternative approaches that EPA should consider?

3. Summary of Peer Review Findings and Recommendations

Regarding Cr and Cr compounds, all three reviewers considered Cr(VI) as the species likely to be driving cancer risks based on solid evidence from the health effects database for Cr and Cr compounds. All three authors also considered EPA's use of the average of the range of the available speciation data (*i.e.,* 12 percent and 18 percent Cr(VI) contained in coal- and oil-fired EGUs, respectively) as a reasonable approach for the derivation of default speciation profiles to be used when there is no speciation data available. All reviewers agreed that there is high uncertainty associated with the variability in the speciation data available for Cr (*e.g.,* range of approximately 4 to 23 percent Cr(VI) from coal-fired units). One of the reviewers recommended several additional studies for EPA's consideration; the EPA considered these in finalizing the report.

Regarding Ni and Ni compounds, the reviewers agreed with the views of the international scientific bodies, which consider Ni compounds carcinogenic as a group. One reviewer recommended that the EPA review several additional Ni speciation data that suggests that sulfidic Ni compounds (which the reviewer considered as the most potent carcinogens within the group of all Ni compounds) are present at low levels in emissions from EGUs. In addition, this reviewer pointed out that there is a recently proposed model that may explain the differences in carcinogenic potential across Ni compounds.

4. The EPA's Responses to Peer Review Recommendations

We summarize EPA's basic responses to the peer review comments below, first for Cr-related issues, and second for Ni-related issues, which are reflected in the revised document.[39]

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[37] U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA–SAB). 2010. *Review of EPA's draft entitled, ''Risk and Technology Review (RTR) Risk Assessment Methodologies: For Review by the EPA's Science Advisory Board with Case Studies—MACT I Petroleum Refining Sources and Portland Cement Manufacturing''. EPA–SAB–10–007. May. Available on-line at: http://yosemite.epa.gov/sab/sabproduct.nsf/4AB3966E263D943A8525771F00668381/$File/EPA-SAB-10-007-unsigned.pdf.*

[38] See section 3.3 of U.S. Environmental Protection Agency (U.S. EPA). 2011c. *Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds.* Office of Air Quality Planning and Standards. October.

[39] U.S. EPA, 2011c.

a. Cr and Cr Compounds

In agreement with the peer reviewers and based on the health effects information available for Cr, the EPA assigns high confidence in the assumption that Cr(VI) is the carcinogenic species driving the risk of Cr-emitting facilities. In agreement with the reviews, the EPA considers derivation of default speciation profiles based on the mass of Cr(VI) a reasonable approach. As suggested by one of the reviewers, the EPA reviewed two potentially relevant studies, one of which showed coal combustion emissions containing as much as 43 percent Cr(VI),[40] which suggests that the EPA's quantitative approach could actually underestimate Cr(VI) inhalation risks. However, the other study reviewed by EPA on speciation of Cr in coal combustion showed Cr(VI) percentage levels close to detection limits (*i.e.,* 3 to 5 percent of total Cr, which was close to the limit of detection in this study).[41] Thus, the more recent speciation data available is unlikely to reduce the uncertainty of the Cr speciation analyses used by EPA as the bases for risk characterization analysis.

In agreement with the peer reviewers, the EPA also recognizes that the confidence in the default speciation profiles is low because the profiles are based on a limited data set with a wide range of percentages of Cr(VI) across the different samples.

b. Ni and Ni Compounds

Based on the views of the major scientific bodies mentioned above and the peer reviewers that commented on EPA's approaches to risk characterization of Ni compounds, the EPA considers all Ni compounds to be carcinogenic as a group and the EPA does not consider Ni speciation or Ni solubility to be strong determinants of Ni carcinogenicity. These scientific bodies also recognize that based on the data available, the precise Ni compound(s) responsible for the carcinogenic effects in humans is not always clear, and that there may be differences in the potential toxicity and carcinogenic potential across Ni compounds. Nevertheless, studies in humans indicate that various mixtures of Ni compounds (including Ni sulfate, sulfides and oxides, alone or in combination) encountered in the Ni refining industries may cause cancer in humans, and there is no reason to expect anything different from this for mixtures of Ni compounds from other emission sources. One of the reviewers suggested we consider views by some authors that believe that water soluble Ni, such as Ni sulfate, should not be considered a human carcinogen. This view is based primarily on a negative Ni sulfate 2-year rodent bioassay by the National Toxicology Program (NTP) (which is different from the positive 2-year NTP bioassay for Ni subsulfide).[42] [43] [44] One review article identifies the discrepancies between the animal and human data (*i.e.,* from studies of cancers in workers inhaling certain forms of Ni versus inhalation studies suggesting different carcinogenic potential in rodents with different Ni compounds) and states that the epidemiological data available clearly support an association between Ni and increased cancer risk, although the article acknowledges that the data are weakest regarding water soluble Ni. In addition, the EPA identified a recent review[45] that highlights the robustness and consistency of the epidemiological evidence across several decades showing associations between exposure to Ni and Ni compounds (including Ni sulfate) and cancer.

Regarding the second charge question on Ni compounds, two reviewers suggested using the URE derived by the TCEQ[46] for all Ni compounds as a group, rather than the one derived by the Integrated Risk Information System (IRIS, 1991)[47] specifically for Ni subsulfide. The third reviewer did not comment on an alternative approach. Considering this, to develop our primary risk estimate, the EPA decided to use a health protective approach by applying 100 percent of the current IRIS URE for Ni subsulfide, rather than assuming that 65 percent of the total mass of emitted Ni might be Ni subsulfide, as used in previous analyses. We used the IRIS URE value because IRIS values are preferred given the conceptual consistency with EPA risk assessment guidelines and the level of peer review that such values receive. We used 100 percent of the IRIS value because of the concerns about the potential carcinogenicity of all forms of Ni raised by the major national and international scientific bodies, and recommendations of the peer reviewers. Nevertheless, taking into account that there are potential differences in toxicity and/or carcinogenic potential across the different Ni compounds, and given that two URE values have been derived for exposure to mixtures of Ni compounds that are two to three fold lower than the IRIS URE for Ni subsulfide, the EPA also considers it reasonable to use a value that is 50 percent of the IRIS URE for Ni subsulfide for providing an estimate of the lower end of a plausible range of cancer potency values for different mixtures of Ni compounds.

Although this report focused primarily on cancer risks associated with emissions containing Ni compounds, it is important to note that comparative quantitative analyses of non-cancer toxicity of Ni compounds indicate that Ni sulfate is as toxic or more toxic than Ni subsulfide or Ni oxide which does not support the notion that the solubility of Ni compounds is a strong determinant of its toxicity.[48] [49]

E. Summary of Results of Revised U.S. EGU Case Studies of Cancer and Non-Cancer Inhalation Risks for Non-Hg HAP

Based on the results of the peer review and public comments on the non-Hg case study chronic inhalation risk assessment, we made several changes to the emissions estimates, dispersion modeling, and risk characterization for the modeled case study facilities. Key changes include (1) changes in emissions, (2) changes in stack parameters for some facilities based on new data received during the

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[40] Galbreath KC, Zygarlicke CJ. 2004. "Formation and chemical speciation of arsenic-, chromium-, and nickel-bearing coal combustion $PM_{2.5}$," *Fuel Process Technol* 85:701–726.

[41] Huggins FE, Najih M, Huffman GP. 1999. "Direct speciation of chromium in coal combustion by-products by X-ray absorption fine structure spectroscopy," *Fuel Process Technol* 78:233–242.

[42] Oller A. 2002. "Respiratory carcinogenicity assessment of soluble nickel compounds." *Environ Health Perspect.* 110:841–844.

[43] Heller JG, Thornhill PG, Conard BR. 2009. "New views on the hypothesis of respiratory cancer risk from soluble nickel exposure; and reconsideration of this risk's historical sources in nickel refineries." *J Occup Med Toxicol.* 4:23.

[44] Goodman JE, Prueitt RL, Thakali S, and Oller AR. 2011. "The nickel iron bioavailability model of the carcinogenic potential of nickel-containing substances in the lung." *Crit Rev Toxicol* 41:142–174.

[45] Grimsrud TK and Andersen A. "Evidence of carcinogenicity in humans of water-soluble nickel salts." *J Occup Med Toxicol.* 2010. 5:1–7. Available online at *http://www.ossup-med.com/content/5/1/7.*

[46] Texas Commission on Environmental Quality (TCEQ). 2011. *Development Support Document for nickel and inorganic nickel compounds.* Available online at *http://www.tceq.state.tx.us/assets/public/implementation/tox/dsd/final/june11/nickel_&_compounds.pdf.*

[47] U.S. EPA, 1991. *Integrated Risk Information Service (IRIS) assessment for nickel subsulfide.* Available at: *http://www.epa.gov/iris/subst/0273.htm.*

[48] Haber LT, Allen BC, Kimmel CA. 1998. "Non-Cancer Risk Assessment for Nickel Compounds: Issues Associated with Dose-Response Modeling of Inhalation and Oral Exposures." *Toxicol Sci.* 43:213–229.

[49] National Toxicology Program (NTP). 1996. *Technical Report Series No. 454, Toxicology and carcinogenesis studies of nickel sulfate hexahydrate.* July. Available online at *http://ntp.niehs.nih.gov/ntp/htdocs/LT_rpts/tr454.pdf.*

public comment period, (3) use of updated versions of AERMOD and its input processors (AERMAP, AERMINUTE, and AERMET), and (4) use of 100 percent of the current IRIS URE for Ni subsulfide to calculate Ni-associated inhalation cancer risks (rather than assuming that the Ni might be 65 percent as potent as Ni subsulfide).

Based on estimated actual emissions, the highest estimated individual lifetime cancer risk from any of the 16 case study facilities was 20 in a million, driven by Ni emissions from the one case study facility with oil-fired EGUs. Of the facilities with coal-fired EGUs, five facilities had maximum individual cancer risks greater than one in a million[50] (the highest was five in a million), with the risk from four due to emissions of Cr(VI) and the risk from one due to emissions of Ni.[51] There were also two facilities with coal-fired EGUs that had maximum individual cancer risks equal to one in a million. All of the facilities had non-cancer Target Organ Specific Hazard Index (TOSHI)[52] values less than one, with a maximum TOSHI value of 0.4 (also driven by Ni emissions from the one case study facility with oil-fired EGUs).

Since these case studies do not cover all facilities in the category, and since our assessment does not include the potential for impacts from different EGU facilities to overlap one another (*i.e.,* these case studies only look at facilities in isolation), the maximum risk estimates from the case studies likely underestimates true maximum risks for the source category.

Based on the fact that six U.S. EGUs were estimated to meet or exceed the CAA section 112(c)(9) criterion of one in a million, EGUs cannot be removed from the list of source categories to be regulated under CAA section 112.

F. Public Comments and Responses to the Appropriate and Necessary Finding

1. Legal Aspects of Appropriate and Necessary Finding

a. History of Section 112(n)(1)(A)

Comment: One commenter provided a detailed history of EPA's regulatory actions concerning EGUs and implementation of CAA section 112(n)(1)(A). The same commenter implies that the EPA's 2000 appropriate and necessary finding and listing of EGUs was flawed because the Agency did not comply with CAA section 307(d) rulemaking process. The commenter sought review of the 2000 notice in the U.S. Court of Appeals for the District of Columbia Circuit, which was dismissed by the D.C. Circuit. *Utility Air Regulatory Group* v. *EPA,* No. 01–1074 (D.C. Cir. July 26, 2001). The commenter then characterizes at length the 2005 EPA action that revised the interpretation of CAA section 112(n)(1)(A) and, which the D.C. Circuit concluded illegally removed EGUs from the CAA section 112(c) list of sources that must be regulated under CAA section 112. *See New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). The commenter notes that the D.C. Circuit did not rule on the legal correctness or the sufficiency of the factual record supporting EPA's 2000 listing decision or on the factual correctness of EPA's later decision to reverse its CAA section 112(n)(1)(A) determination. The commenter noted further that the D.C. Circuit indicated that the listing decision could be challenged when the Agency issued the final CAA section 112(d) standards pursuant to CAA section 112(e)(4). The commenter concluded by asserting that the Agency could not ignore the history associated with the regulation of EGUs under section 112 and that two earlier dockets—Docket ID. No. A–92–55 and Docket ID. No. EPA–HQ–OAR–2002–0056—are also part of this long rulemaking effort and must be accounted for in conjunction with Docket No. EPA–HQ–OAR–2009–0234 if all pertinent material and comments are to be part of the rulemaking record.

Response: The commenter characterizes the regulatory history of the rule EPA proposed on May 3, 2011. To the extent that characterization is inconsistent with the lengthy regulatory history EPA provided in the preamble to the May 3, 2011 rule, we disagree. We address several of the statements in more detail below.

First, the commenter makes much of the fact that the EPA did not go through CAA section 307(d) notice and comment rulemaking when making the appropriate and necessary finding and listing decision in 2000. However, the commenter's complaint is without foundation. The CAA does not require CAA section 307(d) rulemaking for listing decisions. In fact, CAA section 112(e)(4) specifically provides that listing decisions may only be challenged ''when the Administrator issues emission standards for such * * * [listed] category.'' Second, the commenter challenged the listing decision in the U.S. Court of Appeals for the District of Columbia Circuit (Court) and, on July 26, 2001, the Court granted EPA's motion to dismiss that action based on the plain language of CAA section 112(e)(4). Moreover, in addition to the 2000 notice, the EPA clearly articulated its basis for listing EGUs in this proposed rule, which is consistent with CAA section 307(d), and the commenter was provided an ample opportunity to comment. Finally, the commenter asserts that the rulemaking docket for this action is incomplete because the Agency did not include two earlier dockets—Docket ID. No. A–92–55 and Docket ID. No. EPA–HQ–OAR–2002–0056—for the Section 112(n) Revision Rule, 70 FR 15994 (March 29, 2005), and the reconsideration of the Section 112(n) Revision Rule, 71 FR 33388 (June 9, 2006), respectively. The commenter is incorrect because EPA incorporated by reference the two dockets at issue. *See* EPA–HQ–OAR–2009–0234–3056.

Comment: One commenter stated that the EPA has assessed the public health risks posed by HAP emissions from coal- and oil-fired EGUs for the last 40 years. According to the commenter, throughout that time, the EPA has come to a single repeated conclusion that HAP emissions from EGUs pose little or no risk to public health. Based on this conclusion, the EPA has properly chosen not to require EGUs to install expensive, new pollution control equipment to control HAP emissions. The commenter asserts that, in this proposed rule, the EPA shifts its opinion on the health impacts of EGU HAP emissions 180 degrees and now seeks to impose sweeping regulatory requirements on all power plants. According to the commenter, the EPA's newfound concern about HAP emissions from EGUs is not based on new and different assessments of the public health consequences of EGU HAP emissions but instead on health benefits from the reduction of non-hazardous air pollutants, primarily PM, which the Agency is required to regulate under other provisions of the CAA. One

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[50] A risk level of 1 in a million implies a likelihood that up to one person, out of one million equally exposed people would contract cancer if exposed continuously (24 hours per day) to the specific concentration over 70 years (an assumed lifetime). This would be in addition to those cancer cases that would normally occur in an unexposed population of one million people.

[51] When the lower end of the cancer potency range for Ni was used to develop risk estimates, 5 of the 16 facilities had maximum cancer risks exceeding 1 in a million, and the maximum individual cancer risk for any single facility fell to 10 in a million.

[52] The target-organ-specific hazard index (TOSHI) is a metric used to assess whether there is an appreciable risk of deleterious (noncancer) effects to a specific target organ due to continuous inhalation exposures over a lifetime. If a TOSHI value is less than or equal to one, such effects are unlikely. For TOSHI values greater than one, there is an increased risk of such effects.

commenter stated that for decades, the EPA set primary ambient air quality standards that protect public health with an adequate margin of safety, CAA section 109(b)(1), and set secondary standards that are [sic] ''requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air,'' CAA 109(b)(2). The commenter notes that even if EPA now views those past PM standards as inadequate, the EPA has ongoing regulatory proceedings in which it can address any perceived health concerns. The commenter concludes that regulation of EGU HAP emissions under CAA section 112 is an unlawful way to address those concerns.

Response: The commenter is incorrect in its assertion that the Agency has consistently concluded that HAP emissions from EGUs do not present a hazard to public health. In the 2000 finding, the Agency concluded that HAP emissions from coal- and oil-fired EGUs do pose a hazard to public health and determined that it was appropriate and necessary to regulate such units under CAA section 112. As a result of that finding, the EPA added coal- and oil-fired EGUs to the CAA section 112(c) list of source categories for which emission standards are to be established pursuant to CAA section 112(d). Further, in support of the proposed rule, the EPA conducted additional extensive quantitative and qualitative analyses, which confirm that it remains appropriate and necessary to regulate EGUs under CAA section 112. Among other things, those analyses demonstrate that emissions from coal- and oil-fired EGUs continue to pose a hazard to public health. The commenter also fails to note that the EPA found that HAP emissions from EGUs pose a hazard to the environment as well.

The commenter seems confused about the basis for the Agency's appropriate and necessary finding because it maintains that the EPA made the appropriate and necessary finding based on the health co-benefits attributable to PM reductions that will be achieved as a result of the Agency's regulation of HAP emissions from EGUs. Nowhere in the May 2011 proposal does EPA state that it based the appropriate and necessary finding on hazards to public health attributable to PM emissions. The commenter's allegation lacks foundation. The appropriate and necessary finding unmistakably focuses on the hazards to public health and hazards to the environment associated with HAP emissions from EGUs.

Comment: One commenter stated that CAA section 112 required EPA to make a risk-based determination in order to regulate HAP. According to the commenter, the EPA may regulate substances ''reasonably * * * anticipated to result in an increase in mortality or increase in serious illness'' to a level that protects public health with an ''ample margin of safety.'' According to the commenter, the EPA has regulated a number of HAP emitted from industrial source categories other than EGUs.

As for EGUs, according to the commenter, the EPA found that the combustion of fossil fuels produces extremely small emissions of a broad variety of substances that are present in trace amounts in fuels and that are removed from the gas stream by control equipment installed to satisfy other CAA requirements. The commenter stated that the EPA, in past reviews, found that these HAP emissions did not pose hazards to public health. *See* 48 FR 15076, 15085 (1983) (radionuclides). the commenter further stated that ''[i]n the case of Hg specifically, the EPA found that ''coal-fired power plants * * * do not emit mercury in such quantities that they are likely to cause ambient mercury concentration to exceed'' a level that ''will protect public health with an ample margin of safety.'' 40 FR 48297–98 (October 19, 1975) (Hg); 52 FR 8724, 8725 (March. 19, 1987) (reaffirming Hg conclusion).

According to the commenter, in the late 1980s, the EPA was concerned that its prior risk assessments of individual HAP emissions from fossil-fuel-fired power plants may not reflect the total risks posed by all HAP emitted by those sources. The commenter states that the EPA modeled the risks posed by all HAP emitted by power plants (very much like the analyses the Agency would conduct for the Utility Study ten years later). The commenter asserts that the modeling again failed to identify threats to public health that warranted regulation under an ''ample margin of safety'' test.

Response: The commenter's statements concerning the pre-1990 CAA are not relevant to the current action. Congress enacted CAA section 112(n)(1) as part of the 1990 amendments to the Act. That provision requires, among other things, that the Agency evaluate the hazards to public health posed by HAP emissions from fossil-fuel fired EGUs. Had Congress concluded, as commenter appears to assert, that HAP emissions from EGUs did not pose a hazard to public health or the environment, it defies reason that Congress would have required EPA to conduct the three studies at issue in CAA section 112(n)(1) (titled ''Electric utility steam generating units'') and regulate EGUs under section 112 if the Administrator determined in her discretion that it was appropriate and necessary to do so. The Agency complied with the statutory mandates in CAA section 112(n)(1) in conducting the studies and reasonably exercised its discretion in making the appropriate and necessary finding.

We acknowledge that Congress treated radionuclide emissions from EGUs differently. For radionuclides from EGUs (and certain other sources), Congress included CAA section 112(q)(3), which authorizes but does not require the Agency to maintain the regulations of radionuclides in effect prior to the 1990 amendments. The fact that Congress made an exception for radionuclides and no other HAP from EGUs further demonstrates that the HAP-related actions EPA took with regard to EGUs prior to the 1990 amendments to the CAA are not germane.

As for the commenter's statements about Hg emissions from EGUs, we find their conclusions wholly inconsistent with CAA section 112(n)(1). That provision is titled ''Electric utility steam generating units,'' and it directs EPA to conduct two Hg-specific studies. *See* CAA sections 112(n)(1)(B) and 112(n)(1)(C). The commenter's suggestion that the EPA could or should rely on assessments of Hg from EGUs conducted prior to the 1990 amendments is not tenable.

Finally, the commenter stated that the EPA conducted a risk assessment of all HAP from EGUs prior to the 1990 amendments and that the Agency did not identify any HAP that failed the ''ample margin of safety'' test. The commenter did not cite the study or provide any information to support the statements so we are unable to respond to the alleged study directly; however, the risk assessments conducted in support of the appropriate and necessary finding, as well as the 2000 finding, demonstrate that HAP emissions from EGUs pose hazards to public health and the environment.

b. Interpretation of ''Appropriate'' and ''Necessary''

Comment: One commenter stated that in the preamble to the proposed rule, the EPA sets out its ''interpretation of the critical terms in CAA section 112(n)(1),'' arguing that this latest interpretation is ''wholly consistent with the CAA'' and with the Agency's earlier ''2000 finding.'' *See* 76 FR 24976, 24986 (May 3, 2011). The commenter stated that throughout the proposal EPA tries to suggest that it is returning to some earlier, ''correct'' interpretation of CAA section 112(n)(1) set forth in its 2000 action. *See, e.g.,* 76 FR 24989 (''The Agency's interpretation of the term 'appropriate' * * * is wholly consistent with the Agency's appropriate finding in 2000''); id. at 24992 (''Our interpretation of the necessary finding is reasonable and consistent with the 2000 finding''). According to the commenter, the EPA did not provide in 2000 any interpretation of what it now characterizes as the ''critical terms'' of section 112(n)(1). *See, e.g.,* 70 FR 15999 n.13 (the ''2000 finding does not provide an interpretation of the phrase 'after imposition of the requirements of the Act' ''); id. at 16000/2 (in 2000, the EPA ''did not provide an interpretation of the term 'appropriate' ''); 76 FR 24992 (the ''Agency did not expressly interpret the term necessary in the 2000 finding''). The commenter believes that for that reason alone, it is impossible to credit EPA's assertion that it ''appropriately concluded that it was appropriate and necessary to regulate hazardous air pollutants * * * from EGUs'' in 2000, and that it is today merely ''confirm[ing] that finding and conclud[ing] that it remains appropriate and necessary to regulate these emissions.* * *'' [53]

Response: The commenter disagrees with certain statements in the preamble to the proposed rule that provide that the Agency's interpretation of CAA section 112(n)(1) is reasonable and consistent with the 2000 finding. It is difficult to decipher the exact complaint that the commenter has with EPA's proposed rule in this regard, but the commenter does assert that ''the Agency did not provide in 2000 any interpretation of what it now characterizes as the ''critical terms'' of CAA section 112(n)(1).'' The commenter's assertion lacks foundation. Although the 2000 finding did not provide detailed interpretations of the regulatory terms at issue, it discussed the types of considerations relevant to the appropriate and necessary inquiry. For example, it is clear that in 2000, the Agency was concerned with the then current hazards to public health and the environment when assessing whether it was appropriate to regulate EGUs under section 112.[54] In addition, when evaluating whether it was necessary to regulate utilities, the Agency stated that it was necessary to regulate HAP emissions from U.S. EGUs under section 112 because the implementation of the other requirements of the Act would not adequately address the serious public health and environmental hazards arising from HAP emissions from EGUs. The Agency also specifically noted that ''section 112 is the authority intended to address'' hazards to public health and the environment posed by HAP emissions. *Id.*

The detailed interpretation set forth in the preamble to the proposed rule is consistent with the 2000 finding, but EPA does not assert that the interpretation is in any way necessary to support the factual conclusions reached in the 2000 finding. Instead, we noted in the preamble to the proposed rule that our interpretation is consistent with the 2000 finding because in 2005 we interpreted the statute in a manner that was not consistent with the 2000 finding. The commenter has provided no legal support for its position that the Agency erred in interpreting the statute in a manner that is consistent with a prior factual finding.

Comment: Several commenters assert that in the 1990 amendments to the Clean Air Act, Congress directed the EPA to base its determination regarding regulation of fossil-fuel-fired generating units on consideration of any adverse public health effects identified in the study mandated by the first sentence of section 112(n)(1)(A) and that Congress did not dictate in section 112(n)(1)(A) that the EPA must regulate electric utility steam generating units under section 112.

According to the commenters the sponsor of the House bill that became section 112(n)(1)(A) provides an explanation that contradicts the EPA's approach to regulating EGUs:

> Pursuant to section 112(n), the Administrator may regulate fossil fuel fired electric utility steam generating units only if the studies described in section 112(n) clearly establish that emissions of any pollutant, or aggregate of pollutants, from such units cause a significant risk of serious adverse effects on the public health. Thus, * * * he may regulate only those units that he determines—after taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions—have been demonstrated to cause a significant threat of serious adverse effects on the public health.

136 Cong. Rec. H12,934 (daily ed. Oct. 26, 1990) (statement of Rep. Michael Oxley).

The commenters stated that the EPA position is premised on the assumption that ''regulation under section 112'' necessarily means ''regulation under 112(d)'' and falsely premised on the assumption that source categories listed by operation of section 112(n)(1)(A) cannot be regulated differently. The commenters conclude that the language of section 112(n)(1)(a) reflects Congress' intent that ''regulation of HAP from EGUs was not intended to operate under section 112(d) but was instead intended to be tailored to the findings of the utility study mandated by section 112(n)(1)(A).''

Response: The commenters maintain that the Agency's interpretation of CAA section 112(n)(1) is flawed in many respects. The primary support for one commenter's arguments against EPA's interpretation, including in the comment above, is legislative history in the form of statements from one Congressman, Representative Oxley. The Supreme Court has repeatedly stated that the statements of one legislator alone should not be given much weight. *See Brock* v. *Pierce County,* 476 U.S. 253, 263 (1986) (finding that ''statements by individual legislators should not be given controlling effect, but *when they are consistent with the statutory language and other legislative history, they provide evidence of Congress' intent.''*) (*emphasis added*) (citation omitted); *Garcia, et al.,* v. *U.S.,* 469 U.S. 70, 78 (1984), citing *Zuber* v. *Allen,* 396 U.S. 168, 187 (1969) (reiterating its prior findings, the Court indicated that isolated statements ''are 'not impressive legislative history.' ''); *Weinberger, et al.,* v. *Rossi et al.,* 456 U.S. 25, 35 (declining to make a ruling based on ''one isolated remark by a single Senator''); *Consumer Product Safety Comm., et al.* v. *GTE Sylvania, Inc., et al.,* 447 U.S. 102, 117–118 (1980) (declining to give much weight to isolated remarks of one Representative); *Chrysler Corp.* v. *Brown, et al.,* 441 U.S. 281, 311 (1979) (finding that ''[t]he remarks of a single legislator, even the sponsor, are not controlling in analyzing legislative history.''); *Zuber,* 396 U.S. at 186 (concluding that ''[f]loor debates reflect at best the understanding of individual Congressmen.''); and *U.S.* v. *O'Brien,* 391 U.S. 367, 384 (1968) (in evaluating the statements of a handful of Congressmen, the Court concluded that ''[w]hat motivates one legislator to make a speech about a statute is not necessarily what motivates scores of others to enact it. * * *.''). As these cases show, the Supreme Court does not give weight to the statements of an individual legislator, except when the statements are supported by other legislative history and the clear intent of the statute. The commenters cited no case law that would support reliance on such limited legislative history.

The commenter has not cited any other legislative history to support

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[53] *Id.* at 24,977/3.

[54] 65 FR 79830.

Representative Oxley's statement, and the lack of additional support makes the statement of little utility or import under the case law. In fact, there does not appear to be anything in the House, Senate, or Committee Reports that supports Oxley's statement. The lack of support for Oxley's statement in the Committee Report is particularly telling since, as the commenter notes, the House and Senate bills required different approaches to regulating EGUs under section 112, with the Senate bill requiring EGUs be regulated prior to the Utility Study. In fact, legislative statements from Senator Durenberger, a supporter of the Senate version, demonstrate that others would almost certainly not have agreed with Oxley's interpretation. For example, Senator Durenberger stated, ''It seems to me inequitable to impose a regulatory regime on every industry in America and then exempt one category, especially a category like power plants which are a significant part of the air toxics problem.''

Senator Durenberger discussed the negotiations with the Administration and the industry push to avoid regulation, including industry arguments for not regulating Hg from U.S. EGUs:

> The utility industry continued to adamantly oppose [regulation under section 112]. First, they argued that mercury isn't much of an environmental problem. But as the evidence mounted over the summer and it became clear that mercury is a substantial threat to the health of our lakes, rivers and estuaries and that power plants are among the principal culprits, they changed their tactic. Now they are arguing that mercury is a global problem so severe that just cleaning up U.S. power plants won't make enough of a difference to be worth it. They've gone from 'we're not a problem' to 'you can't regulate us until you address the whole global problem.' Recasting an issue that way is not new around here. So, it is not a surprise. But it does suggest the direction in which this debate will be heading in the next few years.

136 Cong. Rec. 36062 (October 27, 1990).

Senator Durenberger also explained why the House version was adopted:

> Given that a resolution of the difficult issues in the conference were necessary to conclude work on this bill, the Senate proposed to recede to the House provision which was taken from the original administration bill. It provides for a 3-year study of utility emissions followed by regulation to the extent that the Administrator finds them necessary.

Id.

Senator Durenberger's statements indicate that it is unlikely that he would agree with Oxley's interpretation of CAA section 112(n)(1), a provision that provides the Agency with considerable discretion, and nothing indicates that others in the Senate (or for that matter anyone else in the House) would agree with that interpretation. Given the Supreme Court's views on the use of such limited legislative history, the EPA reasonably declined to consider (or even discuss) the legislative history in the preamble to the proposed rule and we believe it would be improper to ascribe Representative Oxley's statements to the entire Congress.

Moreover, Representative Oxley's statement directly conflicts with the statutory text. Representative Oxley stated that ''[the Administrator may regulate only those units that he determines—*after taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions*—have been demonstrated to cause a significant threat of serious adverse effects on the public health.'' 136 Cong. Rec. H12934 (daily ed. Oct. 26, 1990), reprinted in 1 1990 Legis. Hist. at 1416–17 *(emphasis added).* However, the Utility Study required under CAA section 112(n)(1)(A) directs the Agency to consider the hazards to public health reasonably anticipated to occur after ''imposition of the requirements of [the Clean Air Act].'' EPA was not required to consider state or local regulations or voluntary emission reduction programs in the Utility Study, and that study is the only condition precedent to making the appropriate and necessary finding.[55]

The legislative history the commenters rely on is not controlling. The Agency believes that it has reasonably interpreted section 112(n)(1)(A), for all the reasons described herein and in the proposal. The commenters also cite Representative Oxley's statements as support for alternative interpretations of CAA section 112(n)(1). We believe that any arguments that rely on such limited legislative history are without merit.

Comment: One commenter stated that the EPA does acknowledge that, in many significant respects, its new interpretation of CAA section 112(n)(1) ''differs from that set forth'' in the Agency's 2005 rulemaking, but argues that its change of position is permissible. *See* 76 FR 24988/1 (''[T]o the extent our interpretation differs from that set forth in the 2005 Action, we explain the basis for that difference and why the interpretation, as set forth in this preamble, is reasonable.''). In support, commenters note that the EPA cites *National Cable & Telecommunication Ass'n* v. *Brand X Internet Services,* 545 U.S. 967 (2005). The commenters agree that it is true that, in *Brand X Internet Services,* the Supreme Court explained that, if an agency ''adequately explains the reasons for a reversal of policy,'' such change is ''not invalidating,'' since the ''whole point of Chevron is to leave the discretion provided by the ambiguities of a statute with the implementing agency.'' 545 U.S. at 981 (internal quotations omitted). The commenters maintain that all Brand X Internet Services was saying is that ''[a]gency inconsistency is not a basis for declining to analyze the agency's interpretation under the *Chevron* framework.'' *Id.*

According to the commenter, it is not enough that the EPA has purported to ''explain'' why it has abandoned the interpretation of CAA section 112(n)(1) adopted in 2005. The commenter states that under the first step of *Chevron*, the Agency's latest interpretation must still be consistent with congressional intent. *See Chevron* v. *NRDC,* 467 U.S. at 842–43. The commenters state that under the second step of Chevron, if there is discretion for EPA to exercise in interpreting the ''critical terms'' of CAA section 112(n)(1), the Agency must properly define the range of that discretion and then act reasonably in exercising that discretion. *See Chevron,* 467 U.S. at 843; *see also Village of Barrington, Ill.* v. *Surface Transportation Bd.,* No. 09–1002 (D.C. Cir. Mar. 15, 2011).The commenters allege that the EPA failed to properly define and exercise the scope of its discretion. In each instance, the commenter maintains that the Agency has departed from the correct interpretation of CAA section 112(n)(1) that it adopted in 2005, seizing instead upon a new approach that is contrary to the plain language of the CAA itself, as interpreted after considering the statements of Representative Oxley.

Response: The commenter appears to argue that the EPA's interpretation of CAA section 112(n)(1) is not consistent with the plain language of the statute, implying that the statute is clear and must be evaluated under step one of Chevron. *See Chevron* v. *NRDC,* 467 U.S. 837 842–42 (1984) (finding that when the legislative intent is clear no additional analysis is required).

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[55] In addition, the EPA only considered CAA requirements in the Utility Study and this was the correct approach because Congress knew how to require consideration of non-Federal requirements when directing EPA to conduct a study or assessment. See CAA section 112(n)(5) (Congress required EPA to conduct an assessment of hydrogen sulfide from oil and gas extraction activities and provided that the assessment ''shall include review of existing State and industry control standards, techniques and enforcement.'').

However, as noted above, much of the commenter's argument that the plain language of the statute precludes EPA's interpretation is based on the unpersuasive legislative history discussed above. As explained in the preamble to the proposed rule, the statute directs the Agency to determine whether it is appropriate and necessary to regulate EGUs under section 112. As the D.C. Circuit has held, the terms ''appropriate'' and ''necessary'' are very broad terms. Because these terms are broad they are susceptible to different interpretations. We believe we have reasonably interpreted the appropriate and necessary language in section 112(n)(1)(A). To the extent that interpretation differs from the one set forth in 2005, we have fully explained the basis for such changes. *See* 76 FR 24986–24993 (setting forth the Agency's interpretation of section 112(n)(1)).

Furthermore, we properly considered the scope of our discretion in interpreting the statute as explained in detail in the preamble to the proposed rule. We believe the interpretation set forth in the preamble to the proposed rule is consistent with the Act and, therefore, the Agency should be afforded deference pursuant to *National Cable & Telecommunication Ass'n* v. *Brand X Internet Services,* 545 U.S. 967 (2005).

Comment: A number of commenters agreed with the Agency's interpretation of section 112(n)(1) and the terms appropriate and necessary. The commenters also agreed that the EPA's interpretation of that provision was reasonable and consistent with the statute.

Response: We agree with the commenters and appreciate their support.

Comment: One commenter asserts that the EPA's ultimate motivation for rejecting its prior interpretation of CAA section 112(n)(1) and embracing this flawed new approach is made clear from the very outset of the proposal. According to the commenter, the EPA touts the fact that ''one consequence'' of the MACT rule would be that the ''market for electricity in the U.S. will be more level'' and ''no longer skewed in favor of the higher polluting units that were exempted from the CAA at its inception on Congress' assumption that their useful life was near an end.'' *See* 76 FR 24979/2. The MACT rule would ''require companies to make a decision—control HAP emissions from virtually uncontrolled sources'' or else ''retire these sometimes 60 year old units and shift their emphasis to more efficient, cleaner modern methods of generation, including modern coal-fired generation.'' Id.

The commenter stated that this remarkably forthright statement establishes that the underlying basis for EPA's proposal to regulate EGUs under CAA section 112 is not to address any ''hazards to public health'' that might be attributed to the emission by EGUs of HAP listed under CAA section 112(b). Rather, according to commenter, the EPA is utilizing the regulation of EGUs under CAA section 112 as a means to an entirely different end: To force the imposition of controls that will also have the result of reducing non-HAP emissions (primarily PM) or force the shutdown of those units for which the cost of such controls would be prohibitive. At the same time, according to commenter, the EPA tacitly acknowledges that it cannot hope to make out a case that the regulation of EGU HAP emissions is ''appropriate and necessary'' within the meaning of CAA section 112(n)(1). The commenter asserts that the only HAP whose health-related benefits EPA quantifies is Hg. Elsewhere, the commenter stated that the EPA contends there are ''additional health and environmental effects'' attributable to HAP other than Hg, but admits that it has ''not quantified'' those risks due supposedly to ''insufficient information.'' *See* 76 FR 24999/2. With respect to Hg the commenter stated that the benefits are so questionable and miniscule, some $4 million to $6 million (given a 3 percent discount rate), that compared to the total social costs of the rule (*i.e.,* nearly $11 billion) the rule cannot be justified were EPA properly to interpret CAA section 112(n)(1) and undertake the sort of regulatory analysis Congress intended. The commenter stated that the reason that the EPA touts in this rulemaking the health benefits EPA attributes to the reduction of non-hazardous air pollutants (again, primarily PM), the regulation of which is authorized under provisions of the CAA apart from CAA section 112, is to elide the inconvenient truth regarding the truly trivial nature of the benefits attributable to HAP regulation itself. The commenter concludes that the EPA distorts CAA section 112(n)(1)(A) ''beyond all recognition.''

One commenter stated that the EPA is directed by CAA section 112(n)(1)(A) to study the ''hazards to public health anticipated to occur as a result of emissions'' by EGUs of ''pollutants listed under subsection (b) of this section''—*i.e.,* HAP and HAP alone. Thereafter, the EPA is authorized to regulate EGU HAP emissions if, and only if, they determine that ''such regulation'' of HAP emissions is ''appropriate and necessary'' to address the ''hazards to public health'' that may be attributable to HAP emissions. According to the commenter, by contrast, in this rulemaking, the EPA has seized upon the fact that the control of EGU HAP emissions will also control non-HAP (such as PM), and then seeks to justify the regulation of HAP emissions based almost entirely on the health benefits of the reductions in non-HAP emissions that would be coincidentally achieved. The commenter believes that this ''regulatory sleight-of-hand'' runs afoul of congressional intent and is unlawful.

Response: The commenter alleges that the health-related benefits to regulating HAP emissions from EGUs are ''questionable and miniscule,'' and that the only real benefits stem from non-HAP emissions, such as PM. The commenter also implies that regulation of HAP is nothing more than a straw man and that the Agency's ultimate goal is to regulate other pollutants, and specifically PM. These allegations are wholly without merit. The Agency has conducted comprehensive technical analyses that confirm that HAP emissions from EGUs pose a hazard to public health. The analyses are discussed at length elsewhere in this final rule, and a review of the proposed and final rules utterly refutes commenter's assertion that PM reductions form the basis for the appropriate and necessary finding. In addition, the commenter appears to ignore the Agency's findings concerning the hazards to public health and the environment posed by HAP emissions simply because the Agency is not able to quantify many of the benefits associated with reductions of HAP emissions from EGUs or because the estimated HAP benefits that are quantified are small in relation to the co-benefits achieved through reductions in non-HAP air pollutants, such as PM and SO_2, which are surrogates for certain HAP. The Agency is regulating EGUs pursuant to section 112(d) for all of the reasons explained in the preamble and discussed elsewhere in this response to comments. The commenter fails to recognize that the statute neither requires a cost-benefit analysis prior to finding it appropriate and necessary to regulate EGUs, nor requires such analysis prior to setting emission standards. Indeed, Congress expressly precluded consideration of costs when setting MACT floors. As explained below, the EPA does not believe that it is appropriate to consider costs when determining whether to regulate EGUs under CAA section 112.

Comment: One commenter stated that the EPA has ignored the language and intent of CAA section 112(n)(1)(A), as interpreted based on Representative Oxley's statements, and that the Agency's interpretation of this provision violates step one of Chevron. Under Chevron where the ''intent of Congress is clear,'' that is the ''end of the matter,'' for both the implementing agency and a reviewing court ''must give effect to the unambiguously expressed intent of Congress.'' Chevron, 467 U.S. at 842–43. The commenter asserts that the legislative history of CAA section 112(n)(1)(A) ''sheds considerable light on Congress' unique approach to regulation of EGUs under CAA § 112.'' According to the commenter, on April 3, 1990, the Senate passed S. 1630. The Senate bill would have required EPA to list EGUs under CAA section 112(c) and to regulate them under the MACT provisions of CAA section 112(d). *See* S. 1630 section 301, 3 1990 Legis. Hist. at 4407. Thereafter, the House of Representatives passed a modified version of S. 1630 on May 23, 1990. This House version substantially changed the provisions of CAA section 112 as they applied to EGUs. *See* 1 1990 Legis. Hist. at 572–73. The House version was virtually identical to the current CAA section 112(n)(1)(A), and was ultimately adopted by the conference committee, enacted by Congress and signed into law. According to the commenter, Congress expressly rejected the ''list-under-(c)-and-regulate-under-(d)'' approach that S. 1630 would have applied to EGUs, and that Congress did choose to apply to other source categories. The commenter stated that the EPA's interpretation that the Agency is ''required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)'' (Id. at 24,993/3) fails to take the legislative history into account, and in a footnote, the commenter states that the Agency erred by not addressing the legislative history as it did in the 2005 action.

Response: For the reasons stated above, we believe commenter's reliance on the single statement of one legislator is flawed. In addition, in a footnote the commenter stated that the EPA recognized ''that it had to address'' the legislative history in its 2005 action, and that the EPA erred in this case because we did not address the legislative history. The commenter cites no case law to support its contention that an Agency must ''address'' unpersuasive legislative history. Further, in the 2005 action, the EPA relegated to a footnote the Oxley statement that commenter relies on so heavily even though the statement supported the interpretation we provided in that rule. We recognized then what the commenter fails to recognize now, which is that the Agency cannot argue that the meaning of CAA section 112(n)(1)(A) is clear based on the statements of one legislator.

Furthermore, the Agency's interpretation does not violate Chevron Step 1. The terms ''appropriate'' and ''necessary'' are ambiguous. The statements of a lone legislator do not transform those ambiguous words into a Chevron Step 1 situation.

Moreover, the commenter's assertion that Congress unambiguously defined the factors to consider in making the appropriate determination is without merit. We fully explain in the preamble to the proposed rule the basis for the Agency's interpretation, and we are not revising that interpretation based on the comments received.

Finally, the EPA notes that the sentence concerning regulation under CAA section 112(d) that the commenter quotes from the preamble states, in full: ''Congress did not exempt EGUs from the other requirements of section 112 and, *once listed*, the EPA is required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d), as described above.'' 76 FR 24993 (*emphasis added*). The EPA discusses requirements to regulate section 112(c) listed sources under section 112(d) in response to other comments.

c. Consideration of Both Environmental Effects and Health Effects From Other Sources

Comment: Several commenters stated that the EPA acts contrary to congressional intent when the Agency considers itself ''thereby authorized to consider 'environmental effects' and the effects of HAP emissions from non-EGU sources, in making its 'appropriate and necessary' finding under subparagraph (n)(1)(A).''

Commenters assert that the EPA misreads CAA section 112(n)(1)(B) and (C) to inject environmental effects in the CAA section 112(n)(1)(A) determination. According to one commenter the plain language of CAA section 112(n)(1) establishes that regulation of EGUs is to be predicated solely on ''hazards to public health'' attributable to HAP emissions. The legislative history providing that the EPA ''may regulate [EGUs] only if the studies described in section 112(n) clearly establish that emissions of any pollutant * * * from such units cause a significant risk of serious adverse risk to the public health'' confirms that plain language. *See* Oxley Statement at 1416–17. The commenter further stated that nothing on the face of CAA section 112(n)(1)(A) indicates that Congress intended that the EPA should (or must) take into account any additional information that might be developed through the other studies mentioned in subparagraphs (n)(1)(B) and (C) (*i.e.*, the Mercury Study[56] and the NAS Study[57]), such as HAP emissions from non-EGU sources. The commenter also identified other provisions of section 112 that specifically require consideration of environmental effects and states that Congress would have requires such consideration in CAA section 112(n)(1) if it had wanted EPA to consider environmental effects.

The commenter makes a related assertion that the EPA acts contrary to congressional intent by assuming authority to assess the '''hazard to public health or the environment [from] HAP emissions from EGUs alone' or the 'result of HAP emissions from EGUs in conjunction with HAP emissions from other sources''' (citing 76 FR at 24,988/1). According to the commenter, the only evident basis for the Agency's interpretation that, in making its ''appropriate and necessary'' finding, the EPA can (and should) take into account HAP emissions from sources other than EGUs, is that the Mercury Study authorized by CAA 112(n)(1)(B) references ''mercury emissions from * * * municipal waste combustion units, and other sources, including area sources,'' in addition to EGUs. The commenter asserts, however, that subparagraph (n)(1)(A) identifies the Utility Study as the sole study to inform EPA's ''appropriate and necessary'' finding. The commenter states that if Congress had intended that the EPA take into account information developed through the Mercury Study, Congress ''would not have specified that the EPA was to predicate its 'appropriate and necessary' finding on the 'results of the study required by this subparagraph' (n)(1)(A).''

Commenter also cites to a number of other section 112 provisions that expressly address environmental effects and the commenter states the only conclusion to draw from the inclusion in those provisions and the absence of such language in section 112(n)(1)(A) is that Congress intended public health to be the only basis for the appropriate and necessary finding.

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[56] U.S. EPA. 1997. *Mercury Study Report to Congress.* EPA–452/R–97–003. December.

[57] NAS, 2000.

Response: The commenter again relies in part on the statements of one legislator to attack EPA's reasoned interpretation of an ambiguous statute. To the extent the commenter's arguments rely on this limited evidence, we refer to the response above. As we stated above, CAA section 112(n)(1) is an ambiguous statutory provision; thus, the EPA's interpretation, not commenter's, is entitled to considerable deference if it is a reasonable reading of the statute. *Chevron*, 467 U.S. at 843–44. For the reasons described herein and in the proposal, we believe that we have reasonably interpreted the statutory terms at issue here. The Agency directs attention to section III.A. of the proposed rule, which includes a thorough discussion of the Agency's interpretation of the relevant statutory terms. To the extent the commenters disagree with EPA's interpretations, the EPA refers back to its discussion in the proposal and responds to the comments as follows.

The commenter appears to maintain that the EPA must interpret the scope of the appropriate and necessary finding solely in the context of the CAA section 112(n)(1)(A) Utility Study, such that only hazards to public health and only EGU HAP emissions may be considered. The commenter incorrectly conflates the requirements for the Utility Study with the requirement to regulate EGUs under CAA section 112 if EPA determines it is appropriate and necessary to do so. The commenter concedes that the Agency may consider information other than that contained in the Utility Study, but only to the extent it relates specifically to hazards to public health directly attributable to HAP emissions from EGUs. We agree that we may consider additional information other than that contained in the Utility Study, as we stated in the preamble to the proposed rule, because courts do not interpret phrases like ''after considering the results of'' in a manner that precludes the consideration of other information. *See United States* v. *United Technologies Corp.*, 985 F.2d 1148, 1158 (2nd Cir. 1993) (''based upon'' does not mean ''solely);[58] *see also* 76 FR 24988. We further explained in the preamble to the proposed rule that it was reasonable to interpret the scope of the appropriate and necessary finding in the context of all three studies required under CAA section 112(n)(1) because the provision is title ''Electric utility steam generating units.''[59] The commenter has provided little more than unpersuasive legislative history to support its restrictive interpretation of our authority. *Id.*

The commenter also argues that the statute clearly prohibits the Agency from considering adverse environmental effects or the cumulative effects of HAP emissions from EGUs and other sources based on its claim that the statute is clear when one *properly* considers the legislative history. Again, the commenter has provided no support for its contention other than the statements of one Representative and the improper conflation of the CAA section 112(n)(1)(A) direction on the conduct of the Utility Study and the appropriate and necessary finding. Congress left it to the Agency to determine whether it is appropriate and necessary to regulate EGUs under CAA section 112 and the statute does not limit the Agency to considering only hazards to public health and only harms directly and solely attributable to EGUs.

The commenter stated that Congress specifically told EPA when it wanted EPA to consider adverse environmental effects in CAA section 112 and cites to several provisions of the Act that require consideration of adverse environmental effects. The commenter ignores CAA section 112(n)(1)(B), which directs the Agency to consider adverse environmental effect. In any event, even were we to view section 112(n)(1)(A) in isolation, as the commenter suggests, we still maintain that we can consider adverse environmental effects under 112(n)(1)(A). Nothing in section 112(n)(1)(A) precludes consideration of environmental effects. Congress required the Agency to assess whether it is appropriate and necessary to regulate EGUs under section 112. We believe that adverse environmental effects can be considered in the appropriate analysis. Congress specifically directed the Agency to consider adverse environmental effects when delisting source categories pursuant to section 112(c)(9), and thus we believe it is reasonable to consider such effects when determining whether it is appropriate to regulate such units under section 112, especially given that Congress did not limit our appropriate and necessary inquiry to the Utility Study. See CAA section 112(c)(9)(B)(ii).

Moreover, the other provisions of CAA section 112 that specifically discuss environmental effects have purposes that are distinguishable from CAA section 112(n)(1), and we do not believe one can reasonably draw the conclusion that the commenter does when comparing those provisions to CAA section 112(n)(1)(A). The lack of a requirement to consider environmental effects in CAA section 112(n)(1)(A) does not equate to a prohibition on the consideration of environmental effects as the commenter concludes. The EPA maintains that it reasonably concluded that we should protect against identified or potential adverse environmental effects absent clear direction to the contrary.

Concerning the consideration of the cumulative effect of HAP emissions from EGUs and other sources, we provided a reasonable interpretation of the statute and noted that our interpretation, unlike commenters, does not ''ignore the manner in which public health and the environment are affected by air pollution. An individual that suffers adverse health effects as the result of the combined HAP emissions from EGUs and other sources is harmed, irrespective of whether HAP emissions from EGUs alone would cause the harm.''[60]

d. Finding for All HAP To Be Regulated

Comment: Several commenters stated that for those EGU HAP for which the Agency makes no CAA section 112(n)(1)(A) determination, their regulation under CAA section 112 is not authorized. For example, one commenter maintains that the Agency could regulate HAP emissions from EGUs under CAA section 112(n). Accordingly, to the extent that the EPA reads CAA section 112, as construed by *National Lime Ass'n,* as compelling it to regulate all HAP emitted by EGUs, should the Agency make an ''appropriate and necessary'' determination under CAA section 112(n)(1)(A) with respect to a single HAP (*e.g.*, Hg), the EPA stands poised to commit a fundamental legal error that will condemn the final rule on review. Cf., *e.g.*, *PDK Laboratories, Inc.*, 362 F.3d at 797–98; *Holland* v. *Nat'l Mining Ass'n*, 309 F.3d at 817 (where an agency applies a Court of Appeals ''interpretation * * * because it believed that it had no choice'' and that it ''was effectively 'coerced' to do so,'' then the agency ''cannot be deemed to have exercised its reasoned judgment'').

Response: We do not agree with the commenter's assertion that Congress intended EPA to regulate only those EGU HAP emissions for which an appropriate and necessary finding is

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[58] Several commenters have taken issue with our citation to *United States* v. *United Technologies Corp.* because the language at issue in that case was ''based upon'' and the language of section 112(n)(1)(A) is ''after considering the results of.'' We believe that, if anything, ''based upon'' is more prescriptive than ''after considering the results of'' such that the case supports the Agency's interpretation that additional information other than the Utility Study may be considered in making the appropriate and necessary finding.

[59] 76 FR 24986–87.

[60] 76 FR 24988.

made, and the commenter has cited no provision of the statute that states a contrary position. The EPA reasonably concluded that we must find it ''appropriate'' to regulate EGUs under CAA section 112 if we determine that a single HAP emitted from EGUs poses a hazard to public health or the environment. If we also find that regulation is necessary, the Agency is authorized to list EGUs pursuant to CAA section 112(c) because listing is the logical first step in regulating source categories that satisfy the statutory criteria for listing under the statutory framework of CAA section 112. *See New Jersey,* 517 F.3d at 582 (stating that ''[s]ection 112(n)(1) governs how the Administrator decides whether to list EGUs. * * *''). As we noted in the preamble to the proposed rule, D.C. Circuit precedent requires the Agency to regulate all HAP from major sources of HAP emissions once a source category is added to the list of categories under CAA section 112(c). *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (D.C. Cir. 2000). 76 FR 24989.

The commenter does not explain its issues with our interpretation of how regulation under section 112 works—*i.e.* making a determination that a source category should be listed under CAA section 112(c), listing the source category under CAA section 112(c), regulating the source category under CAA section 112(d), and conducting the residual risk review for sources subject to MACT standards pursuant to CAA section 112(f). Instead, it asserts that our decision is flawed because the interpretation we provided does not account for all the alternatives for regulating EGUs under section 112, and that we have not properly exercised our discretion leading to a fatal flaw in our rulemaking.

The commenter also ignores the language of section 112(n)(1)(A). As explained in the proposed rule, the use of the terms section, subsection, and subparagraph in section 112(n)(1)(A) demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing EPA's action under section 112(n)(1)(A). Congress directed the Agency to regulate utilities ''under this section,'' not ''under this subparagraph,'' and accordingly EGUs should be regulated under section 112 in the same manner as other categories for which the statute requires regulation. Furthermore, the D.C. Circuit Court found that section 112(n)(1) ''governs how the Administrator decides whether to list EGUs'' and that once listed, EGUs are subject to the requirements of section 112. *New Jersey,* 517 F.3d at 583. Indeed, the D.C. Circuit Court expressly noted that ''where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly,'' noting that ''section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants.'' *Id.* Congress did not exempt EGUs from the other requirements of section 112, and once listed, the EPA is reasonably regulating EGUs pursuant to the standard-setting provisions in section 112(d), as it does for all other listed source categories.

The commenter provided no alternative theory for regulating EGUs under CAA section 112, other than to state that the EPA could regulate under CAA section 112(n)(1). However, even assuming for the sake of argument, that we could issue standards pursuant to CAA section 112(n)(1), we would decline to do because there is nothing in section 112(n)(1)(A) that provides any guidance as to how such standards should be developed. Any mechanism we devised, absent explicit statutory support, would likely receive less deference than a CAA section 112(d) standard issued in the same manner in which the Agency issues standards for other listed source categories. We would also decline to establish standards under section 112(n)(1) because Congress did provide a mechanism under CAA sections 112(d) and (f) for establishing emission standards for HAP emissions from stationary sources and it is reasonable to use that mechanism to regulate HAP emissions from EGUs.

e. Considering Costs in Finding

Comment: Several commenters assert that the EPA must consider costs in assessing whether regulation of EGUs is appropriate under CAA section 112(n)(1)(A). Commenters posit that the EPA's position that ''the term 'appropriate' * * * does not allow for the consideration of costs in assessing whether hazards * * * are reasonably anticipated to occur based on EGU emissions,'' 76 FR at 24,989/1, does not withstand scrutiny. According to the commenters, the treatment of ''costs'' under section 112(c) does not support the Agency's position, and the process by which sources may be ''delisted'' under section 112(c)(9), including no consideration of costs, sheds no light on the circumstances under which it may be ''appropriate'' to regulate EGUs under section 112(n)(1)(A).

Commenters characterize as ''unintelligible'' the EPA's position that it is ''reasonable to conclude that costs may not be considered in determining whether to regulate EGUs'' when ''hazards to public health and the environmental are at issue (citing 76 FR at 24989). ''Two commenters stated that a natural reading of the term ''appropriate'' would include the consideration of costs. According to the commenters, something may be found to be ''appropriate'' where it is ''specially suitable,'' ''fit,'' or ''proper.'' *See* Webster's Third New International Dictionary at 106 (1993). The term ''appropriate'' carries with it the connotation of something that is ''suitable or proper in the circumstances.'' *See* New Oxford American Dictionary (2d Ed. 2005). Considering the costs associated with undertaking a particular action is inextricably linked with any determination as to whether that action is ''specially suitable'' or ''proper in the circumstances.'' One commenter notes that in 2005 (70 FR 15994, 16000; March 29, 2005) the EPA used the dictionary definition of ''appropriate,'' as being ''especially suitable or compatible'' and that it would be difficult to fathom how a regulatory program could be either ''suitable'' or ''compatible'' for a given public health objective without consideration of cost.

One commenter asserts that on the face of CAA section 112(n)(1)(A), it is clear that the EPA is expected to consider costs. According to the commenter, that Congress intended that the EPA investigate and consider ''alternative control strategies'' for emissions as part of the section 112 (n)(1) Utility Study when making the ''appropriate and necessary'' determination refutes the notion that the Agency can, and indeed must, disregard the cost of regulation in making that determination, because the cost of a given emission ''control strategy'' is a central factor in any evaluation of ''alternative'' controls.

Further, according to commenters, it is well-settled that CAA regulatory provisions should be read with a presumption in favor of considering costs (citing *Michigan* v. *EPA,* 213 F.3d 663, 678 (D.C. Cir. 2000)), and the legislative history of section 112(n)(1)(A) confirms that Congress intended EPA to consider costs (citing Oxley Statement at 1417).

Commenters also assert that the EPA falsely represents that it ''did not consider costs when making the ''appropriate'' determination in the EPA's December 2000 notice (76 FR at 24,989/2).

Response: The commenters first take issue with EPA's explanation of why the Agency determined that costs should not be considered in making the appropriate determination. What commenters do not identify is an express statutory requirement that the Agency consider costs in making the appropriate determination. Congress treated the regulation of HAP emissions differently in the 1990 CAA amendments because the Agency was not acting quickly enough to address these air pollutants with the potential to adversely affect human health and the environment. *See New Jersey,* 517 F.3d at 578. Specifically, following the 1990 CAA amendments, the CAA required the Agency to list source categories and nothing in the statute required us to consider costs in those listing decision, and we have not done so when listing other source categories. Thus, it is reasonable to make the listing decision, including the appropriate determination, without considering costs.

The commenters next argue that the Agency is compelled by the statute to consider costs based on a dictionary definition of ''appropriate'' and the CAA section 112(n)(1)(A) direction to consider alternative control strategies for regulating HAP emissions in the Utility Study.

Concerning the definition of ''appropriate'', commenters stated:

> Not only is it ''reasonable'' for EPA to consider costs in determining whether it is ''appropriate'' to regulate EGU HAP emissions, a natural reading of the term indicates that excluding the consideration of costs would be entirely unreasonable. Something may be found to be ''appropriate'' where it is ''specially suitable,'' ''fit,'' or ''proper.'' *See* Webster's Third New International Dictionary at 106 (1993). The term ''appropriate'' carries with it the connotation of something that is ''suitable or proper in the circumstances.'' *See* New Oxford American Dictionary (2d Ed. 2005) at 76. Considering the costs associated with undertaking a particular action is inextricably linked with any determination as to whether that action is ''specially suitable'' or ''proper in the circumstances.''

The EPA believes the definition of ''appropriate'' that the commenters provide wholly support its interpretation and nothing about the definition compels a consideration of costs. It is appropriate to regulate EGUs under CAA section 112 because EPA has determined that HAP emissions from EGUs pose hazards to public health and the environment, and section 112 is ''specially suitable'' for regulating HAP emissions, and Congress specifically designated CAA section 112 as the ''proper'' authority for regulating HAP emissions from stationary sources, including EGUs. Section 112 of the CAA is ''suitable [and] proper in the circumstances'' because EPA has identified a hazard to public health and the environment from HAP emissions from EGUs and Congress directed the Agency to regulate HAP emissions from EGUs under that provision if we make such a finding. Cost does not have to be read into the definition of ''appropriate'' as commenter suggests. In addition, as stated elsewhere in response to comments, the Agency does not consider costs in any listing or delisting determinations, and the EPA maintains that it is reasonable to assess whether to list EGUs (*i.e.* the appropriate and necessary finding) without considering costs.

The commenters' argument that costs must be considered based on the CAA section 112(n)(1)(A) requirement to ''develop and describe alternative control strategies'' in the Utility Study is equally flawed. The argument is flawed because Congress did not direct the Agency to consider in the Utility Study the costs of the controls when evaluating the alternative control strategies. In addition, the EPA did not consider the costs of the alternative controls in the Utility Study, as implied by the commenter. Thus, even viewing section 112(n)(1)(A) in isolation, there is nothing in that section that compels EPA to consider costs. For the reasons described herein, we do not believe that it is appropriate to consider costs in determining whether to regulate EGUs under section 112.

Additionally, one commenter attempts to refute EPA's statement in the preamble to the proposed rule that the EPA did not consider costs in the 2000 finding by pointing to the only two mentions of cost in that notice. However, the EPA did not say that costs were not mentioned in the 2000 finding and a review of the regulatory finding will show that costs were not considered in the regulatory finding. 65 FR 79830 (December 20, 2000) (''Section III. What is EPA's Regulatory Finding?'').

f. Considering Requirements of the CAA in ''Necessary''

Comment: Several commenters disagree with EPA's position that it need consider ''only those requirements that Congress directly imposed on EGUs through the CAA as amended in 1990,'' for which ''EPA could reasonably predict HAP emission reductions at the time of the Utility Study.'' According to the commenters, the statutory language of CAA section 112(n)(1) requires that the EPA consider the scope and effect of EGU HAP emissions after the imposition of all of the ''requirements'' of the CAA, not just the Acid Rain program. The commenter maintains that it would have been easy enough for Congress in subparagraph 112(n)(1)(A) to specify ''after imposition of the requirements of Title IV of this chapter,'' but Congress did not. The commenters further add that the legislative history confirms that Congress meant something much broader than that, providing that the EPA is authorized to regulate EGUs under CAA section 112 only after ''taking into account compliance with all provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions.'' The commenters stated that the CAA's ''requirements'' include the submission by states of ozone and fine PM attainment demonstrations, as well as SIP provisions needed to reach attainment of the NAAQS because such provisions could include controls on EGUs to reduce SO_2 and NO_X, which controls could also result in a reduction in Hg emissions.

Response: The commenter's characterization of the facts is flawed and its reliance on legislative history that is in direct conflict with the express terms of the statute is unpersuasive.

On the facts, the EPA explained in the preamble to the proposed rule its interpretation of the phrase ''after imposition of the requirements of [the Act]'' as it related to the conduct of the Utility Study.[61] We reasonably concluded that, since Congress only provided 3 years after enactment to conduct the study, the phrase referred to requirements that were directly imposed on EGUs through the CAA amendments and for which the Agency could reasonably predict co-benefit HAP emission reductions. *Id.* The EPA did not state that the phrase only applied to the Acid Rain program, as commenter asserts, and the Utility Study in fact discussed other regulations, including the NSPS for EGUs and revised NAAQS. With regard to the latter, the EPA ultimately determined that it could not sufficiently quantify the reductions that might be attributable to the NAAQS because states are tasked with implementing those standards. *See* Utility Study, pages ES–25, 1–3, 2–32. Conversely, commenter's position is that the EPA must consider implementation of *all* the requirements of the CAA, but it does not indicate how in conducting the Utility Study the Agency could have possibly considered co-benefit HAP reductions attributable to all future CAA requirements. The Agency appropriately considered the other requirements of the Act in the Utility Study and considered those requirements in determining that it was

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[61] 76 FR 24990.

necessary to regulate coal- and oil-fired EGUs in December 2000.

Although not required, the Agency in the preamble to the proposed rule conducted further analyses in support of the 2000 finding. In doing so, we considered a number of requirements that far exceed what Congress contemplated when enacting CAA section 112(n)(1)(A)), and our analyses still show that it remains necessary to regulate coal- and oil-fired EGUs under section 112. 76 FR 24991.

We maintain that we have reasonably interpreted the requirement to consider the hazards to public health and the environment reasonably anticipated to occur after imposition of the requirements of the Act as explained in the preamble to the proposed rule.[62] In addition, as stated above, we also believe it would be reasonable to find it necessary to regulate HAP emissions from EGUs based on our finding that such emissions pose a hazard to public health and the environment today without considering future reductions that we currently project to occur as the result of imposition of CAA requirements that are not yet effective (*e.g.,* CSAPR).

Moreover, Representative Oxley's statement cited by the commenter is not consistent with the express terms of CAA section 112(n)(1)(A) on this issue. Representative Oxley stated that the EPA was to take ''into account compliance with all the provisions of the act and any other Federal, State, or local regulation and voluntary emission reductions,'' but CAA section 112(n)(1)(A) directs the Agency to consider ''imposition of the requirements of this chapter,'' which means the CAA. The Agency reasonably focused on the requirements of the Clean Air Act, which are federally enforceable, and declined to include potential future reductions that may be attributable to voluntary emission reduction programs or state and local regulations that have no basis in the Clean Air Act and are not federally enforceable. In addition to the statutory direction not to consider such requirements, the EPA believes it is reasonable not to include potential reductions attributable to such requirements because the Agency cannot assure that such requirements and the attendant HAP reductions will remain absent regulation under section 112. Finally, the commenter implies that EPA's position is that the Agency will only consider requirements of the Act that directly regulate HAP emissions. The EPA never stated or suggested that interpretation and a fair reading of the proposed rule will demonstrate that EPA considered requirements that achieve co-benefit HAP emission reductions, for example the Transport Rule (known as CSAPR).

Comment: One commenter stated that, under CAA section 112, regulating EGUs is permissible only insofar as it is focused, targeted, and predicated on concrete findings by the Agency that such regulation is indeed ''necessary.'' According to the commenter, the EPA construes CAA section 112(n)(1)(A) as permitting it to find that it is ''necessary'' to regulate EGUs even where the Agency does not actually know whether it is ''necessary'' to regulate EGUs. Citing the D.C. Circuit, the EPA suggests that '''there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible,''' in order to '''achieve a particular end.''' 76 FR 24990, quoting *Cellular Telecommunications* v. *FCC,* 330 F.3d 502, 510 (D.C. Cir. 2003). The commenter stated that in the ''context'' of CAA section 112(n)(1)(A), as informed by the relevant legislative history from Representative Oxley, it is clear that regulation of EGU HAP emissions can be considered ''necessary'' only if EPA were to ''clearly establish'' that such regulation was effectively ''indispensible'' to address the identified harm. As EPA concedes that it has made no such determination here, its proposal is fatally flawed for that reason alone.

The commenter further asserts that the EPA erred when it concluded that it may '' 'determine it is necessary to regulate under section 112' when the Agency is 'uncertain whether imposition of the requirements of the CAA will address the identified hazards''' (citing 76 FR at 24,991/3). According to the commenter, the EPA ''cannot take refuge in its own 'uncertainty' to support a finding that it is 'necessary' to regulate EGUs under section 112, and the Act precludes the EPA from '''err[ing] on the side of regulation''' in face of uncertainty (*id.*). The commenter also implies that the finding was based on non-HAP emissions.

Response: The commenter again relies on the legislative statements of one Representative and asserts that the statements are controlling. The EPA disagrees with commenter and maintains that its interpretation of the term ''necessary'' is reasonable. 76 FR 24990–92 (Section III.A.2.b of the preamble to the proposed rule contains the EPA's interpretation of the term ''necessary''.) 76 FR 24990–92 (Section III.A.2.b of the proposed rule contains EPA's interpretation of the term ''necessary''.) The commenter also, in a footnote, implies that EPA based the appropriate and necessary finding on non-HAP air pollution. The commenter is wrong as explained in more detail above.

As an initial matter, this comment is only addressing one aspect of the Agency's interpretation of the term necessary. As EPA stated at proposal:

> If we determine that the imposition of the requirements of the CAA will not address the identified hazards, EPA must find it necessary to regulate EGUs under section 112. Section 112 is the authority Congress provided to address hazards to public health and the environment posed by HAP emissions and section 112(n)(1)(A) requires the Agency to regulate under section 112 if we find regulation is ''appropriate and necessary.'' If we conclude that HAP emissions from EGUs pose a hazard today, such that it is appropriate, and we further conclude based on our scientific and technical expertise that the identified hazards will not be resolved through imposition of the requirements of the CAA, we believe there is no justification in the statute to conclude that it is not necessary to regulate EGUs under section 112.

76 FR 24991.

The EPA has determined that the imposition of the requirements of the CAA will not address the hazards to public health or hazards to the environment that EPA has identified; therefore, it is necessary to regulate EGUs under CAA section 112.

The EPA further interpreted the statute to allow the Agency to find that it is necessary to regulate EGUs under other circumstances, and it is with one of our additional interpretations that commenter takes issue. Specifically, the commenter argues that EPA's interpretation authorizes the Agency to find it necessary to regulate EGUs when we are uncertain it is necessary, but that misconstrues our interpretation and the record. At proposal, the EPA stated:

> In addition, we may determine it is necessary to regulate under section 112 even if we are uncertain whether the imposition of the requirements of the CAA will address the identified hazards. Congress left it to EPA to determine whether regulation of EGUs under section 112 is necessary. We believe it is reasonable to err on the side of regulation of such highly toxic pollutants in the face of uncertainty. Further, if we are unsure whether the other requirements of the CAA will address an identified hazard, it is reasonable to exercise our discretion in a manner that assures adequate protection of public health and the environment. Moreover, we must be particularly mindful of CAA regulations we include in our modeled estimates of future emissions if they are not

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[62] 76 FR 24990.

> final or are still subject to judicial review ([*e.g.*], the Transport Rule). If such rules are either not finalized or upheld by the Courts, the level of risk would potentially increase.

Id.

The CAA requires EPA to exercise its discretion in determining whether regulation under section 112 is necessary, and the D.C. Circuit has stated that ''there are many situations in which the use of the word 'necessary,' in context, means something that is done, regardless of whether it is indispensible, to achieve a particular end.'' *See Cellular Telecommunications & Internet Association, et al.* v. *FCC,* 330 F.3d 502, 510 (D.C. Cir. 2003). The EPA's interpretation of ''necessary'' is reasonable in the context of CAA section 112(n)(1)(A).

The commenter stated that EPA concedes that the Agency has not ''clearly established'' that regulation of HAP emissions under CAA section 112 is ''indispensible.'' The EPA has conceded nothing but, more importantly, the supposed standard that the commenter presents for evaluating whether it is necessary to regulate HAP emissions from EGUs is not required by the statute. Even the limited legislative history on which the commenter incorrectly relies does not espouse such a standard. The commenter specifically takes issue with EPA's statement that the Agency may find it is necessary to regulate EGUs under CAA section 112 if we are ''uncertain whether imposition of the other requirements of the CAA will sufficiently address the identified hazards.'' 76 FR at 24990. The commenter has again misinterpreted the Agency's position by stating that ''EPA construes CAA section 112(n)(1)(A) as permitting it to find that it is ''necessary'' to regulate EGUs even where the Agency does not actually know whether it is ''necessary'' to regulate EGUs.'' Instead, the EPA maintains that it may be necessary to regulate EGUs under CAA section 112 if we identify a hazard to public health or the environment that is appropriate to regulate today and our projections into the future do not clearly establish that the imposition of the requirements of the CAA will address the identified hazard in the future. Making a prediction about future emission reductions from a source category is difficult for statutory provisions that do not mandate direct control of the given source category or pollutants of concern. We maintain that erring on the side of caution is appropriate when the protection of public health and the environment from HAP emissions is not assured based on our modeling of future emissions.

Furthermore, as we stated in the preamble to the proposed rule, we believe it would be reasonable to find it appropriate *and* necessary to regulate EGUs under section 112 today based on a determination that HAP emissions from EGUs pose a hazard to public health and the environment without considering future HAP emission reductions. 76 FR 24991, n.14. We maintain this is reasonable because ''Congress could not have contemplated in 1990 that EPA would have failed in 2011 to have regulated HAP emissions from EGU's where hazards to public health and the environment remain.'' *Id.* The phrase ''after imposition of the requirements of [the Act]'' as contemplated CAA section 112(n)(1)(A) could be read to apply only to those requirements clearly and directly applicable to EGUs under the 1990 CAA amendments, all of which have been implemented and still hazards to public health and the environment from HAP emissions from EGUs remain.

g. Listing EGUs Under 112

Comment: One commenter stated that even if EPA were to establish under CAA section 112(n)(1)(A) that it is ''appropriate and necessary'' to regulate HAP emissions from EGUs, regulating those emissions in the form of a MACT standard established pursuant to CAA section 112(d) is contrary to the plain language of the Act. According to the commenter, if EPA proceeds to finalize the proposal and adopts such a standard, the rule will for this reason alone be ''dead-on-arrival''. According to the commenter, the EPA apparently believes that its only option in regulating EGU HAP emissions is establishing a MACT standard under CAA section 112(d). In the preamble to its proposal, the commenter states that EPA contends that, ''once the appropriate and necessary finding is made,'' EGUs are then ''subject to section 112 in the same manner as other sources of HAP emissions''—*i.e.,* by ''listing'' EGUs under CAA section 112(c) and adopting a MACT standard under CAA section 112(d). *See* 76 FR 24993/2 (emphasis added). The commenter further stated that, given that Congress ''directed the Agency to regulate utilities 'under this section' [*i.e.,* CAA section 112],'' EPA continues, it follows that ''EGUs should be regulated in the same manner as other categories for which the statute requires regulation.'' Id. (emphasis added). The commenter asserts that as EPA sees it, because ''Congress did not exempt EGUs from the other requirements of section 112,'' once EGUs were ''listed'' under CAA section 112(c), the Agency was ''required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d).'' Id. at 24,993/3 (emphasis added).

The commenter stated that, in support of this reading of the CAA, the EPA invokes the decision of the U.S. Court of Appeals for the D.C. Circuit in *New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008). The commenter further alleged that, according to EPA, the D.C. Circuit has ''already held that section 112(n)(1) 'governs how the Administrator decides whether to list EGUs.' '' *See* 76 FR 24993/2–3, quoting 517 F.3d at 583. The commenter stated that EPA construes that holding as indicating that, ''once listed, EGUs are subject to the requirements of section 112''—including, the EPA presumes, CAA section 112(d). Id. The commenter stated that elsewhere, the EPA construes CAA section 112(n)(1) (A) as ''govern[ing] how the Administrator decides whether to list EGUs for regulation under section 112,'' and quotes the D.C. Circuit's observation in *New Jersey* that ''Section 112(n)(1) governs how the Administrator decides whether to list EGUs; it says nothing about delisting EGUs.'' *See* 76 FR 24981/2, quoting 517 F.2d at 582.

The commenter asserts that EPA misinterprets the ''under this section'' language of CAA section 112(n)(1); overstates the significance of the *New Jersey* decision; and, as a consequence, misapprehends the scope of its own discretion to formulate regulatory standards for EGUs under CAA section 112. In light of these errors, the commenter maintains that EPA should withdraw the proposed MACT rule.

One commenter stated that if Congress had intended that EPA regulate EGU HAP emissions only through a MACT standard, Congress could have—and presumably would have—directed the Agency to regulate EGU emissions ''under CAA section 112(d).'' Thus, the commenter maintained that EPA's authority to regulate EGU HAP emissions is not derived from any particular subsection of CAA section 112. Rather, the commenter stated that EPA is authorized to regulate ''under this section''—*i.e.,* CAA section 112 generally—as may be ''appropriate and necessary.'' The commenter stated that there is nothing on the face of CAA section 112(n)(1)(A) that specifies that regulation of EGUs must occur under CAA section 112(d). To the contrary, according to the commenter, a plain reading of CAA section 112(n)(1)(A), as interpreted based on the Oxley statement, indicates that establishing a

MACT standard for EGUs under CAA section 112(d) is not what Congress had in mind at all.

Response: We do not agree with the commenter. The EPA interpreted CAA section 112(n)(1)(A) in a manner that gives meaning to all the words used in the provision. *See NRDC* v. *EPA,* 489 F.3d 1364, 1373 (D.C. Cir. 2007) (admonishing EPA for an interpretation of CAA section 112(c)(9) that ignored certain words and the context in which they were used. The Court stated that ''EPA's interpretation would make the words redundant and one of them 'mere surplusage,' which is inconsistent with a court's duty to give meaning to each word used by Congress.'') (*citing TRW Inc.* v. *Andrews, 534 U.S. 19, 31, 122 S. Ct. 441, 151 L. Ed. 2d 339 (2001)).* Specifically, in the preamble to the proposed rule, we stated:

> The statute directs the Agency to regulate EGUs under section 112 if the Agency finds such regulation is appropriate and necessary. Once the appropriate and necessary finding is made, EGUs are subject to section 112 in the same manner as other sources of HAP emissions. Section 112(n)(1)(A) provision provides, in part, that: '[t]he 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) of this section after imposition of the requirements of this chapter. * * * 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*.'' *Emphasis added.*

In the first sentence, Congress described the study and directed the Agency to evaluate the hazards to public health posed by HAP emissions listed *under subsection* (b) (*i.e.,* CAA section 112(b)). The last sentence requires the Agency to regulate *under this section* (*i.e.,* CAA section 112) if the Agency finds such regulation is appropriate and necessary after considering the results of the study required by this subparagraph (i.e., CAA section 112(n)(1)(A)). The use of the terms ''section'', ''subsection'', and ''subparagraph'' demonstrates that Congress was consciously distinguishing the various provisions of CAA section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs if the Agency finds it appropriate and necessary to do so. Congress directed the Agency to regulate utilities ''under this section,'' and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation. *See* 76 FR 24993.

We maintain that our interpretation of the statute gives meaning to all the words, and the commenter's interpretation does not give any particular meaning to the requirement to ''regulate under this section [112]''. The commenter is correct that Congress could have in CAA section 112(n)(1)(A) directed EPA to regulate HAP from EGUs under CAA section 112(d) after making the appropriate and necessary finding, but the commenter presumes too much when it stated that Congress would have directed the Agency to regulate HAP emissions from EGUs in such a manner if that is what Congress wanted, simply by including the phrase ''regulate under this paragraph'' or ''regulate under this subparagraph'' instead of directing the Agency to ''regulate under this section''. It did not do so.

As we explained in the section II.A. of the proposed rule, CAA section 112 establishes a mechanism to list and regulate stationary sources of HAP emissions. 76 FR 24980–81. Regulation under CAA section 112 generally requires listing under CAA section 112(c), regulation under CAA section 112(d), and, for sources subjected to MACT standards, residual risk regulations under CAA section 112(f) (as necessary to protect human health and the environment with an ample margin of safety). A determination that EGUs should be listed once the prerequisite appropriate and necessary finding is made is wholly consistent with the language of section 112(n)(1)(A), and listed sources must be regulated under CAA section 112(d). *See* CAA section 112(c)(2); *see also New Jersey*, 517 F.3d at 583 (112(n)(1)(A) ''governs how the Administrator decides whether to list EGUs'').

As noted above, Congress used the terms section, subsection, and subparagraph in section 112(n)(1)(A). The use of these three terms demonstrates that Congress was consciously distinguishing between the various provisions of section 112. Congress directed the Agency to regulate utilities ''under this section,'' and accordingly EGUs should be regulated in the same manner as other categories for which the statute requires regulation.

Furthermore, the flaws in the commenter's interpretation are highlighted by other CAA section 112 provisions wherein Congress provided specific direction as to the manner of regulation. For example, CAA section 112(m)(6) requires the Administrator to determine ''whether the other provisions of *this section* [112] are adequate'' and also indicates that ''[a]ny requirements promulgated pursuant to this *paragraph* * * * shall only apply to the coastal waters of the States which are subject to [section 328 of the CAA].'' (*emphasis added*).

In addition, CAA section 112(n)(3) provides that when the Agency is ''promulgating any standard under this section [112] 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.'' Finally, CAA section 112(n)(5) directs the Agency to assess hydrogen sulfide emissions from oil and gas extraction and ''develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment * * * *using authorities under [the CAA] including [section 111] of this title and this section [112].*'' (*emphasis added*). We believe these provisions provide ample evidence that Congress knew how to alter or caveat regulation under CAA section 112 when that was its intent. For these reasons, we believe commenter's argument is without merit.

Comment: Two commenters stated that CAA section 112(n)(1)(A) does not specify that regulation of EGUs must proceed under CAA section 112(d). According to the commenter, an argument could be made, therefore, that the CAA accords EPA with the discretion to regulate EGUs using strategies other than emission standards in CAA section 112(d). The commenters also state that section 112(n)(1)(A) of the CAA requires that EPA ''develop and describe'' alternative control strategies for emissions which may warrant regulation under CAA section 112. According to the commenters if Congress meant for EPA to have one sole regulatory option, i.e., regulation of EGUs only under CAA section 112(d), then the development of alternative control strategies would be rendered meaningless because under CAA section 112(d)(3), the EPA is required to determine the level of control that is achieved by the best performing existing units for which it has data and then to impose that level of control on all existing units. The commenter further states that the development of ''alternative control strategies'' has no role to play in this process. One commenter does note that the consideration of ''alternative'' controls becomes relevant, if at all, only in those circumstances where EPA might seek to establish a ''Beyond-the-Floor'' MACT standard pursuant to CAA section 112(d)(2).

Response: The commenters are correct that CAA section 112(n)(1)(A) directed the Agency to develop and describe in the Utility Study report to Congress alternative control strategies for HAP emissions from EGUs that may warrant regulation in the Utility Study, but the commenters' interpretation of and conclusion based on that language are both factually and legally inaccurate.

The commenters appear to interpret the word ‘‘alternative control strategies’’ to mean something other than the traditional control technologies and control measures that are used to control HAP emissions from EGUs. We do not believe that is a reasonable interpretation of the statute, and the Agency did not interpret the statute in that manner when it conducted the Utility Study. In Chapter 13 of the Utility Study, the EPA considered a range of control measures that would reduce the different types of HAP emitted from EGUs. *http://www.epa.gov/ttn/atw/combust/utiltox/eurtc1.pdf.* The EPA considered pre-combustion controls such as coal washing, fuel switching, and gasification; combustion controls such as boiler design; post-combustion controls such as fabric filters, scrubbers, and carbon absorption; and alternative controls strategies such as demand-side management, energy conservation, and use of alternative fuels (*e.g.*, biomass) or renewable energy. The options discussed in the Utility Study for controlling HAP emissions from EGUs are almost universally available to comply with a CAA section 112(d) standard.

Given the manner in which the Agency conducted the Utility Study, the EPA interpreted the statutory direction as a requirement to set forth the potential alternative control options available to EGUs to comply with CAA section 112 standards in the event the Agency determined regulation under section 112 was appropriate and necessary. The EPA's development and discussion in the Utility Study of alternative control strategies for complying with the standards would help prepare EGUs to comply with the standards if promulgated. Thus, the EPA interpreted the direction to address control strategies in the Utility Study as a request to identify the controls available to EGUs for addressing HAP emissions, and such information would, of course, be relevant if EPA determined that such emissions warranted regulation under section 112.

Furthermore, the EPA establishes CAA section 112(d) standards for stationary sources and it is the responsibility of the sources to comply with the standards using any mechanism available, including pre-combustion and post-combustion measures. Also, the establishment of a MACT standard under CAA section 112(d)(2) and (3) is a two-step process. In the first step, the Agency establishes a floor based on the performance of the best controlled unit or units. *See* CAA section 112(d)(3). In the second step, the Agency must consider additional measures that may reduce HAP emissions and adopt such measures if reasonable after considering costs and non-air quality health and environmental effects. *See* CAA section 112(d)(2). Under the second step, the Agency can consider any measure that reduces HAP emissions even if no source in the category is employing the option under consideration. So, even under the commenter's flawed interpretation of ‘‘alternative control strategies’’, the direction in CAA section 112(n)(1)(A) is not a ‘‘pointless exercise’’ for the development of CAA section 112(d) standards as the Agency considers relevant technologies and HAP emission reduction approaches in evaluating whether to set a more stringent beyond the floor standard.

Comment: One commenter points to CAA section 307(d)(1)(C) and notes that CAA section 112(n) is listed among the provision for which the rulemaking requirements of CAA 307(d) apply. Commenter maintains that this inclusion creates an expectation under the statute that EPA may establish regulatory standards under CAA 112(n). The commenter points to CAA sections 112 (n)(1), (n)(3), and (n)(5) and states that those provisions specifically discuss regulation under CAA section 112 and that EPA must explain why CAA 307(d)(1)(C) states ‘‘any regulation under’’ CAA 112(n) to defend regulation of utilities under section 112(d). The commenter then implies that EPA erred by not even mentioning this provision at proposal.

The commenter also takes issue with EPA's statement in the proposed rule that ‘‘use of the terms section, subsection, and subparagraph’’ ‘‘demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs,’’ if EPA determines that it is appropriate and necessary to regulate EGUs. See 76 FR at 24,993/2.

One commenter does not agree with the EPA's finding that the word ‘‘subsection’’ in the first sentence of CAA section 112(n)(1)(A) demonstrates that Congress was consciously distinguishing between the various provisions of CAA section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs,’’ were the EPA to ‘‘find[ ] it appropriate and necessary to do so.’’ *See* 76 FR 24993/2. According to the commenter, the only evident reason that the word ‘‘subsection’’ is used in the first sentence of CAA section 112(n)(1)(A) is because the reference is made to the ‘‘pollutants’’ which the Utility Study is to address—*i.e.*, the ‘‘pollutants’’ that are emitted by EGUs and which are ‘‘listed under subsection (b)’’ of CAA section 112. Similarly, the word ‘‘subparagraph’’ is used in the last sentence of CAA section 112(n)(1)(A) to identify ‘‘the study’’ which the EPA is directed to undertake by subparagraph (A) of CAA section 112(n)(1)—*i.e.*, the Utility Study. That the last sentence of subparagraph (n)(1)(A) also states that EPA ‘‘shall regulate electric utility steam generating units under this section’’ does not even imply—much less expressly communicate—that regulation ‘‘under this section’’ must mean ‘‘regulation under section 112(d).’’ The commenter stated that Congress was ‘‘consciously distinguishing’’ between the ‘‘various provisions of section 112’’ for the sake of clarity in the drafting of CAA section 112(n).

The commenter also asserts that the EPA mistakenly relies on section 112(c)(6) when the EPA states that ‘‘ ‘where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly. Congress did not exempt EGUs from the other requirements of section 112,’ ’’ and thus the Agency is ‘‘ ‘required to establish emission standards for EGUs consistent with the requirements set forth in section 112(d)’ ’’ (citing 76 FR at 24,993 (internal quotation omitted)).

According to the commenter, nothing in section 112(c)(6) indicates how (or even whether) EGU HAP emissions should be regulated under section 112; paragraph (c)(6) serves only to reiterate that the regulation of such emissions is to occur (if at all) as is provided by section 112(n)(1). The commenter also asserts that the EPA mistakenly relies on *New Jersey.* According to the commenter, the D.C. Circuit in that case did not indicate that the language of section 112(c)(6) should, or could, be construed to mean that EGUs must be regulated under a MACT standard adopted pursuant to section 112(d).

Response: The commenter makes a number of arguments that appear to take issue with the EPA's determination that EGUs should be regulated under CAA section 112(d) if the Agency determines that regulation of HAP emissions from such units is appropriate and necessary.

The commenter implies that the EPA erred because alternative mechanisms for regulation of EGUs under CAA section 112 might exist. We do not agree.

The commenter's argument that the EPA erred because we did not explain why section CAA section 307(d)(1)(C) contemplates regulations under CAA section 112(n) is without merit. It is correct that the Agency believes EGUs should be regulated in the same manner as other sources if the appropriate and necessary finding is made because of the structure of CAA section 112. Nothing in CAA section 112(n)(1) requires or implies that the Agency should or must establish standards for EGUs under that provision. Furthermore, unlike CAA sections 112(n)(3) and 112(n)(5) that commenter cites, CAA section 112(n)(1)(A) does not provide any guidance concerning the manner in which EPA is authorized or required to regulate sources under CAA section 112. *See* CAA section 112(n)(3) (specifically authorizing identified control measures and other requirements for consideration in issuing standards under CAA section 112); see also CAA section 112(n)(5) (directing the Agency to develop and implement a control strategy for emissions of hydrogen sulfide using any authority available under the CAA, including sections 112 and 111, if regulation is appropriate). For these reasons, we disagree that any error occurred because we did not specifically discuss in this proposed rule whether we could or should regulate EGUs under CAA section 112(n)(1) instead of CAA section 112(d).[63] The Agency validly listed EGUs in 2000 and listed sources must be regulated pursuant to CAA section 112(d).

Even if we agreed that regulation under CAA section 112(n)(1) was a viable option for EGUs, we would still have listed and regulated EGUs like other sources because CAA section 112(d) provides a statutory framework for regulating HAP emissions from sources and CAA section 112(n)(1) does not. We believe that even if CAA section 112(n)(1) were available to regulate EGUs, there would be sufficient uncertainty about the legal vulnerability of such an approach to caution against employing it. This legal uncertainty would be particularly troubling in light of the fact that we have identified hazards to public health and the environment from HAP emissions from EGUs that warrant regulation, and these regulations are long overdue.

The commenter also takes issue with our statement in the preamble to the proposed rule that the use of the words ''section'', ''subsection'', and ''subparagraph'' in CAA section 112(n)(1)(A) ''demonstrates that Congress was consciously distinguishing the various provisions of section 112 in directing the conduct of the study and the manner in which the Agency must regulate EGUs.'' *See* 76 FR 24993. The commenter appears to make much of our use of the word ''must'' in that sentence and also states that our interpretation of the significance of the use of the three terms in CAA section 112(n)(1)(A) is flawed because Congress only used the three terms for purposes of clarity. The commenter is incorrect on both points. With respect to the commenter's concern regarding the use of the word ''must'' in the sentence quoted above, we note that in the next sentence we stated that ''Congress directed the Agency to regulate utilities 'under this section,' and accordingly EGUs *should* be regulated in the same manner as other categories for which the statute requires regulation.'' Id. (*emphasis added*). We were not foreclosing the possibility of any alternative interpretation and our use of the term ''must'' should not detract from the point we were trying to make. Specifically, we believe that Congress would have directed us to regulate EGUs under CAA section 112(n)(1)(A) if that was its intent and, absent that mandate, the better reading of the statute is the one provided in the preamble to the proposed rule, which is that EGUs should be listed pursuant to CAA section 112(c) and subject to CAA section 112(d) emission standards.

The commenter also stated that the EPA relied on CAA section 112(c)(6) to support a conclusion that EGUs must be regulated under CAA section 112(d). The commenter takes the EPA's statements out of context. The statement in whole read:

> Furthermore, the D.C. Circuit Court has already held that section 112(n)(1) ''governs how the Administrator decides whether to list EGUs'' and that once listed, EGUs are subject to the requirements of CAA section 112. *New Jersey*, 517 F.3d at 583. Indeed, the D.C. Circuit Court expressly noted that ''where Congress wished to exempt EGUs from specific requirements of section 112, it said so explicitly,'' noting that ''section 112(c)(6) expressly exempts EGUs from the strict deadlines imposed on other sources of certain pollutants.'' *Id.* Congress did not exempt EGUs from the other requirements of CAA section 112, and once listed, EPA is required to establish emission standards for EGUs consistent with the requirements set forth in CAA section 112(d), as described below. *See* 76 FR 24993.

As can be seen from this passage, the Court cited section 112(c)(6) as an example of Congress' intent regarding regulating EGUs under CAA section 112. The commenter cited the last clause of the last sentence of the paragraph quoted above without including the prefatory clause ''once listed,'' and, without that clause, the statement is not fairly characterized. The point the EPA was making in that paragraph is that EGUs are a listed source category and listed sources must be regulated under CAA section 112(d) unless the EPA delists the source category.

Comment: One commenter stated that EPA overstates the significance of the D.C. Circuit's holding in *New Jersey* by suggesting that the decision mandates EGU regulation under CAA section 112(d) because EGUs ''remain listed'' under CAA section 112(c), *See New Jersey*, 517 F.3d at 582. According to the commenter, the court declined to address the lawfulness of EPA's having ''listed'' EGUs under CAA section 112(c), leaving that matter to be decided if and when EPA adopted standards for EGUs under CAA section 112. Nowhere in the decision did the D.C. Circuit indicate that EPA must regulate EGUs under CAA section 112(d).

According to the commenter, the EPA must consider both whether the regulation of EGUs is ''appropriate and necessary'' under section 112(n)(1) and address anew whether the Agency is authorized by section 112 to list EGUs under section 112(c) at all. The commenter asserts that on the face of the proposal, the EPA has not revisited the question whether the ''listing'' of EGUs under section 112(c) is consistent with congressional intent.

Response: The commenter's arguments are circular and it is difficult to fully determine exactly what its issue is with EPA's listing; however, it appears that the commenter believes that EPA incorrectly relied on the *New Jersey* decision to justify the listing of EGUs. The commenter also appears to argue that the Agency has never explained why it has the authority to list EGUs at all. We disagree.

As stated in the preamble to the proposed rule, CAA section 112(n)(1)(A)

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[63] We note that in our January 2004 proposed rule, we solicited comment on whether section 112(n)(1)(A) provided independent authority to regulate EGUs. We received several comments on this issue, and we rejected the concept after reviewing the comments and further considering the language of section 112(n)(1)(A) and the structure of section 112. As such, we proposed and are finalizing that once the Agency determines that it is appropriate and necessary to regulate EGUs under section 112, those sources are listed pursuant to subsection 112(c), as we did in December 2000, and the Agency must set standards for those sources pursuant to section 112(d). See section 112(c) and (d)(1) (requiring establishment of 112(d) standards for listed source categories).

requires EPA to conduct a study of HAP emissions from EGUs and regulate EGUs under CAA section 112 if we determine that regulation is appropriate and necessary, after considering the results of the study. 76 FR 24981, 24986, and 24998. The only condition precedent to regulating EGUs under CAA section 112 is a finding that such regulation is appropriate and necessary (after conducting and considering the Utility Study), and once that finding is made the Agency has the authority to list EGUs under CAA section 112(c) as the first step in the process of establishing regulations under section 112. The D.C. Circuit agrees with that interpretation of the statute as evidenced by its statement in *New Jersey* that ''section 112(n)(1)(A) governs how the Administrator decides whether to list EGUs for regulation under section 112,'' 517 F.3d at 582, and the Court's statement directly contradicts the commenter's position.

The EPA did not rely on the *New Jersey* decision to justify the appropriate and necessary finding as the commenter suggests. We based the finding in 2000 on the extensive information available to the Agency at the time, and we confirmed the finding in the preamble to the proposed rule based on new information. The commenter had ample opportunity to comment on the appropriate and necessary finding, and it may challenge the basis of the listing (*i.e.* the appropriate and necessary finding) when EPA issues the final standards.

Comment: One commenter believes that the D.C. Circuit will condemn the final rule as a result of EPA's ''misapprehension'' that upon making an ''appropriate and necessary'' finding, the Agency is compelled by the CAA to adopt a regulatory standard for EGUs under CAA section 112(d). According to the commenter, a regulation will be invalid if the regulation '' 'was not based on the [agency's] own judgment' '' but '' 'rather on the unjustified assumption that it was Congress' judgment that such [a regulation] is desirable' or required.'' *See Transitional Hospitals Corp.* v. *Shalala*, 222 F.3d 1019, 1029 (D.C. Cir. 2000), quoting *Prill* v. *NLRB*, 755 F.2d 941, 948 (D.C. Cir. 1985). The commenter further notes that the D.C. Circuit has held that, where an agency wrongly construes a judicial decision as compelling a particular statutory interpretation, and thereby unduly limits the scope of its own discretion, the agency's action cannot be sustained. *See, e.g., Phillips Petroleum Co.* v. *FERC*, 792 F.2d 1165, 1171 (D.C. Cir. 1986). The commenter believes the rule is bound to be rejected and that the EPA should ''reconsider the legal interpretations on which it purports to base its rule.''

Response: We do not agree that we have improperly interpreted the statute as limiting our discretion in the manner suggested by the commenter. The commenter makes only one specific allegation in this comment and that concerns the Agency's conclusion that it must establish CAA section 112(d) standards for EGUs in light of the *New Jersey* decision. The commenter does not explain why that conclusion is incorrect. As we state above and in the preamble to the proposed rule, because EGUs are a CAA section 112(c) listed source category, the Agency must establish CAA section 112(d) standards or delist EGUs pursuant to CAA section 112(c)(9). *See New Jersey*, 517 F.3d at 582–83 (holding that EGUs remain listed under section 112(c)); *see also* CAA section 112(c)(2) (requiring the Agency to ''establish emission standards under subsection [112] (d)'' for listed source categories and subcategories); 76 FR 24998–99. We concluded in the preamble to the proposed rule that we could not delist EGUs because our appropriate and necessary analysis showed that EGUs did not satisfy the CAA section 112(c)(9)(B)(i) delisting criteria. *Id.* We did not address in the preamble to the proposed rule whether EGUs satisfied the CAA section 112(c)(9)(B)(ii) criteria because EGUs failed the first prong of the delisting provisions. *Id.* We reach the same conclusion in the final rule and also address the delisting petition submitted by this commenter. Because we cannot delist EGUs, we must regulate them under CAA section 112(d). The commenter has provided no legitimate argument to rebut this conclusion. *See also* previous responses regarding regulation under section 112(n)(1)(A).

Comment: One commenter alleges that EPA impermissibly relied on CAA section 112(c)(9) to interpret ''hazards to public health'', and argues that the ''residual risk'' provisions in CAA section 112(f)(2) are more appropriate for the establishment of standards for EGUs. The commenter stated that by using CAA section 112(c)(9)(B)(i) in defining ''hazards to public health'', the Agency has seized on the one interpretation of the phrase that is surely contrary to congressional intent and, thus, falls outside the permissible range of its interpretative discretion. The commenter maintains that the ''delisting'' criteria of CAA section 112(c)(9) are simply irrelevant to the decision whether EGU HAP emissions will present any ''hazards to public health'' sufficient to warrant regulation of those emissions under CAA section 112.

The commenter also argues that Congress intended that EGUs be treated differently from all other ''major sources'' to which the ''delisting'' provisions of CAA section 112(c)(9), and the standard-setting provisions of CAA section 112(d) necessarily and automatically apply. Therefore, according to the commenter, the EPA's proposal to utilize the criteria of CAA section 112(c)(9) to inform its findings under CAA section 112(n)(1)(A) treats EGUs exactly the same as all other major source categories, is contrary to congressional intent, and thus unlawful. The commenter goes on to state that in exercising its discretion to define ''hazards to public health'' as the phrase is used in CAA section 112(n)(1)(A), the EPA would be better served to consider the ''residual health risk'' provisions of CAA section 112(f)(2). Those provisions provide a better analogy to the establishment of standards for EGUs under CAA section 112 than do the ''delisting'' criteria of CAA section 112(c)(9).

The commenter believes the category-specific criteria of paragraph (c)(9) are a poor fit for an evaluation of ''hazards to public health'' that should reasonably include such factors as the affected population, the characteristics of exposure, the nature of the health effects, and the uncertainties associated with the data. The commenter states that, while CAA section 112(n)(1)(A) does not expressly include any requirement that EGU emissions be regulated with an ''ample margin of safety,'' that standard is more appropriate than the ''one-in-a-million'' cancer risk standard of CAA section 112(c)(9)(B)(i) that EPA proposes to employ.

Response: The commenter acknowledges that EPA has broad discretion to interpret the phrase ''hazard to public health'' but argues that the one thing we cannot do is use the CAA section 112(c)(9)(B) delisting provisions as a benchmark in making that interpretation. The commenter asserts that the use of the delisting standard is clearly contrary to Congressional intent but it does not provide any substantive rebuttal to our conclusion that the CAA section 112(c)(9) standards reflects the level of hazard which Congress concluded warranted continued regulation. Instead, the commenter reverted to its argument that the statute treated EGUs differently. The EPA views the disparate treatment of EGUs in a different light than commenter. While it is true that Congress established a different statutory provision governing whether to add EGUs as a regulated source category under section 112, we do not interpret CAA section 112(n)(1)(A) as providing Congressional license to ignore risks that Congress determined warranted regulation for all other source categories. Because CAA section 112(c)(9) defines that level of risk, it is reasonable to consider it when evaluating whether EGU HAP emissions pose hazards to public health.

The commenter also suggests that the ''ample margin of safety standard'' of CAA section 112(f)(2) is a better fit than the one-in-a-million standard set forth in CAA section 112(c)(9)(B)(1) for evaluating hazards to public health. The commenter asserts that an evaluation of ''hazards to public health'' should include such factors as the affected population, the characteristics of exposure, the nature of the health effects, and the uncertainties associated with the data. However, the EPA did not rely solely on the delisting provisions for evaluating hazards to public health as commenter suggests. In fact, the EPA considered all of the factors the commenter suggests in making our finding.[64] Thus, we decline to adjust our approach to evaluating hazards to public health and the environment based on the comments.

h. 2000 Finding (and 2005 Delisting)

Comment: Several commenters generally support EPA's 2000 finding that regulating HAP emissions from EGUs under CAA section 112 is ''appropriate and necessary.'' According to the commenters, the 2000 finding was proper under the CAA and within EPA's discretion, well-supported based on sound science available to the Agency at the time on the harm from HAP emitted by EGUs, and no additional information makes the finding invalid. Several commenters cited the conclusions of the Utility Study[65] and Mercury Study,[66] which they assert supported the finding and satisfied the only prerequisite for the finding. One commenter specifically asserted that the 2000 finding was well-supported by the Utility Study's conclusions that (1) there was a link between anthropogenic Hg emissions and MeHg found in freshwater fish, (2) Hg emissions from coal-fired utilities were expected to worsen by 2010, and (3) MeHg in fish presents a threat to public health from fish consumption. One commenter noted that the CAA does not require a conclusive link between HAP emissions and harm. One commenter stated that the CAA grants the Administrator discretion in her finding, and that discretionary decision should not be overly scrutinized, citing court opinion.[67] In support of the finding, one commenter stated that it would not make sense for Congress to limit HAP emissions from small businesses such as dry cleaners but to exempt U.S. EGUs, which are the largest sources of many HAP emissions. One commenter agreed that finding was further supported because numerous control options were available to reduce HAP emissions. One commenter agreed with the 2000 finding that the Agency lacked sufficient evidence to conclude that non-Hg HAP from EGUs posed no hazard.

The commenters who generally supported the 2000 finding also commented on specific aspects of the finding. Several commenters asserted that while the evidence on Hg alone supports the finding, the potential harm from non-Hg HAP further supported the 2000 finding. Several commenters noted that new science continues to support the 2000 finding. Several commenters also stated that the ''appropriate'' finding was further supported because numerous control options were available at the time of the finding that would reduce HAP emissions. One commenter concurred with EPA that regulating natural gas-fired EGUs was not appropriate and necessary because the impacts due to HAP emissions from such units are negligible based on the results of the Utility Study.

Several commenters addressed the 2005 reversal of the 2000 finding. Several commenters specifically supported the vacatur of the 2005 action. Other commenters asserted that the 2005 action was proper, and that EPA reverted back to the 2000 finding in the proposed rule without adequate explanation or support. Several commenters cited the 2005 action as invalidating the 2000 finding, specifically noting that EPA concluded that ''no hazards to public health'' remained after accounting for emission reductions under CAIR. These commenters assert that EPA's current position is illegal because EPA took the exact opposite position on the interpretation of the term ''necessary'' in its 2005 reversal, and, thus, deserves no judicial deference. One commenter stated that in 2005 EPA recognized the potential for excessive regulation created by CAA section 112 and determined that the 2000 finding lacked foundation.

Several commenters generally disagreed with the 2000 finding, with two commenters stating that EPA did not have a rational justification for it and another claiming that it was fraught with misinformation and overestimating assumptions. One commenter claimed that EPA did not explain the terms ''appropriate'' and ''necessary'' in the 2000 finding and that the emission control analysis was inadequate. Two commenters stated that the 2000 finding was based on data that was more than 10 years old, which causes serious concern regarding the validity of the findings because technology, the regulatory environment, and the economic climate have evolved. Furthermore, because the Utility Report underestimated emissions controls that EGUs would install by 2010 and additional controls that would be later required by the CSAPR, the basis for EPA's 2000 finding has changed. Several commenters stated that a ''plausible link'' between anthropogenic Hg and MeHg in fish is not an adequate reason for the 2000 finding. Several commenters claim that EPA only identified health concerns for Hg (and potentially Ni) but not other HAP from coal-fired EGUs in the 2000 finding, and, thus, cannot regulate HAP other than Hg because the 2000 finding authorizes only the regulation of Hg. One commenter questioned the Hg emissions underlying the 2000 finding, specifically the fraction of total deposition attributable to U.S. EGUS and the fact that EPA projected an increase in U.S. EGU emissions from 1990 to 2010 though emissions actually declined.

Several commenters raised procedural issues related to the 2000 finding. Several commenters stated that the 2000 finding failed to provide public notice and comment. According to the commenters, the CAA requires that any decision made under CAA section 112(n) must go through public notice and comment. The commenters further stated that the failure to provide public notice and comment means that this MACT is outside EPA's statutory authority. One commenter stated that because the 2000 finding was never ''fully ventilated'' in front of the D.C. Circuit, the EPA's authority to regulate EGUs under CAA section 112(d) is directly at issue. The commenters claim that specific issues did not undergo

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[64] 76 FR 24992.

[65] U.S. EPA 1998. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress. EPA–453/R–98–004a. February.

[66] U.S. EPA, 1997.

[67] ''Where a statute is precautionary in nature, the evidence difficult to come by, uncertain, or conflicting because it is on the frontiers of scientific knowledge, the regulations designed to protect the public health, and the decision that of an expert administrator, [courts] will not demand rigorous step-by-step proof of cause and effect.'' *Ethyl Corp.* v. *EPA*, 541 F.2d 1, 28 (Ct. App. D.C. Circ. 1978).

public notice and comment, including least-cost regulatory options, the impact of regulation on electricity reliability, and EPA's interpretation of the requirements under CAA section 112(n)(1)(A). One commenter claims that EPA attempted to provide after-the-fact support for its 2000 finding with new legal analysis and new factual information, contrary to *New Jersey* v. *EPA* that held that EPA may not revisit its 2000 finding except through delisting under CAA section 112(c)(9). One commenter stated that EPA's 2000 finding should be reviewed when EPA issues the actual NESHAP.[68] One commenter stated that the 2000 finding ignored EO 12866.

Response: EPA agrees with the commenters that the 2000 finding was reasonable and disagrees with the commenters asserting that the 2000 finding was unreasonable or failed to follow proper procedural requirements.

The EPA agrees that reviewing courts defer to the reasoned scientific and technical decisions of an Agency charged with implementing complex statutory provisions such as those at issue in this case. As EPA stated in the preamble to the proposed rule, the EPA maintains that the 2000 finding was reasonable and based on well-supported evidence available at the time, including the Utility Study, the Mercury Study,[69] and the NAS study,[70] which all showed the hazards to public health and the environment from HAP emitted from EGUs. New technical analyses conducted by EPA confirm that it remains appropriate and necessary to regulate HAP emissions from EGUs. Furthermore, the EPA agrees with the commenters on several points raised, specifically that EGUs were and remain the largest anthropogenic source of several HAP in the U.S., that risk assessments supporting the 2000 finding indicated potential concern for several non-Hg HAP, and that several available control options would effectively reduce HAP emissions from U.S. EGUs.

The EPA agrees with the commenters that Congress did not exempt EGUs from section 112(d) HAP emission limits while simultaneously limiting emissions at other sources with less HAP emissions. Congress simply provided EPA with a separate path for listing EGUs by requiring that the Agency evaluate HAP emissions from EGUs and determine whether regulation under CAA section 112 was appropriate and necessary. Since 1990, the EPA has promulgated regulations requiring the use of available control technology and other practices to reduce HAP emissions for more than 170 source categories. U.S. EGUs are the most significant source of HAP in the country that remains unaddressed by Congress's air toxics program. The EPA listed EGUs in 2000 because the considerable amount of available data supported the conclusion that regulation of EGUs under CAA section 112 was appropriate and necessary. That finding was valid at the time, and EPA reasonably added EGUs to the CAA section 112(c) list of sources that must be regulated under CAA section 112.

The EPA acknowledges that we did not expressly define the terms appropriate and necessary in the 2000 finding, but the finding is instructive in that it shows that EPA considered whether HAP emissions from EGUs posed a hazard to public health and the environment and whether there were control strategies available to reduce HAP emissions from EGUs when determining whether it was appropriate to regulated EGUs.[71] When concluding it was necessary, the Agency stated that imposition of the requirements of the Act would not address the identified hazards to public health or environment from HAP emissions and that section 112 was the proper authority to address HAP emissions.[72] The EPA explained in the preamble to the proposed rule its conclusion that the 2000 finding was fully supported by the information available at the time,[73] and EPA stands by the conclusions in that notice. Furthermore, the EPA provided an interpretation of the terms appropriate and necessary that is wholly consistent with the 2000 finding. The EPA does not agree with the commenters that a quantification of emissions reductions or a specific identification of the available controls was necessary to support the 2000 finding and listing. The EPA considered the Utility Study when making the finding, and that study clearly articulated the various alternative control strategies that EGUs could employ to control HAP emissions.[74] As to emission reductions, the EPA cannot estimate the level of HAP emission reductions until the Agency proposes a CAA section 112(d) standard after a source category is listed.

The EPA disagrees with commenters that suggest it was not ''rational'' to determine that it was appropriate to regulate HAP emissions from EGUs due to the cancer risks identified in the Utility Study or the potential concerns associated with other HAP emissions from EGUs. Nothing in CAA section 112(n)(1)(A) suggests that EPA must determine that every HAP emitted by EGUs poses a hazard to public health or the environment before EPA can find it appropriate to regulate EGUs under CAA section 112. In fact, the EPA maintains that it must find it appropriate and necessary to regulate EGUs under CAA section 112 if it determines that any one HAP emitted from EGUs poses a hazard to public health or the environment that will not be addressed through imposition of the requirements of the Act. The EPA disputes the commenters' conclusion that the 2000 finding was limited to Hg and Ni emissions, but, even if it were, the EPA reasonably concluded that EGUs should be listed pursuant to CAA section 112(c) based on the Hg and Ni finding. As stated in the 2000 finding, cancer risks from some non-Hg metal HAP (including As, Cr, Ni, and Cd) were not low enough to be to eliminate as potential concern.[75] Source categories listed for regulation under CAA section 112(c) must be regulated under CAA section 112(d), and the D.C. Circuit has stated that EPA has a ''clear statutory obligation to set emission standards for each listed HAP''. *See Sierra Club* v. *EPA*, 479 F.3d 875, 883 (D.C. Cir. 2007), *quoting National Lime Association* v. *EPA*, 233 F.3d 625, 634 (D.C. Cir. 2000). Therefore, even if EPA concluded that CAA section 112(n)(1) authorized a different approach for regulating HAP emissions from EGUs, the chosen course which is supported by the CAA (*i.e.*, listing under CAA section 112(c)) requires the Agency to regulate under CAA section 112(d) consistent with the statute and case law interpreting that provision.

The EPA disagrees that there is any concern regarding the validity of the 2000 finding or that the emissions information provided in the 2000 finding makes the finding ''questionable'' as stated by some of the commenters. The EPA maintains that the 2000 finding was sound and fully supported by the record available at the time, including the future year emissions projections. Therefore, the listing of EGUs is valid based on that finding alone. Even though Hg emissions have decreased since the 2000 finding instead of increasing as projected, the new technical analyses confirm that Hg emissions from EGUs continue to pose hazards to public

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[68] *See UARG* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001).

[69] U.S. EPA, 1997.

[70] NAS, 2000.

[71] 65 FR 79830.

[72] *Id.*

[73] 65 FR 24994–24996.

[74] *See* Chapter 13 of the Utility Study (U.S. EPA, 1998).

[75] 76 FR 79827.

health and the environment. The EPA also indicated potential concern for several non-Hg HAP in the 2000 finding. It is well established that even small amounts of HAP can cause significant harm to human health and the environment.

The EPA agrees with the commenters who assert that the 2005 action was in error and disagrees with the commenters that the 2005 action invalidated the 2000 finding. As fully described in the preamble to the proposal, the EPA erred in the 2005 action by concluding that the 2000 finding lacked foundation. The 2005 action improperly conflated the ''appropriate'' and ''necessary'' analyses by addressing the ''after imposition of the requirements of the Act'' in the appropriate finding as well as the necessary finding. The EPA also indicated that it was not reasonable to interpret the necessary prong of the finding as a requirement to scour the CAA for alternative authorities to regulate HAP emissions from stationary sources, including EGUs, when Congress provided section 112 for that purpose. The EPA asserts that the 2000 finding was sound and fully supported by the record available at the time for all the reasons stated in this final rule and the proposed rule. The 2005 action interpreted the statute in a manner inconsistent with the 2000 finding and attempted to delist EGUs without complying with the mandates of CAA section 112(c)(9)(B). *See New Jersey*, 517 F.3d at 583 (vacating the 2005 ''delisting'' action). In the preamble to the proposed rule, the EPA set forth a revised interpretation of CAA section 112(n)(1) that is consistent with the statute and the 2000 finding. The EPA also explained in the preamble to the proposed rule why the 2005 action was not technically or scientifically sound. The EPA specifically addressed the errors associated with the 2005 action in the preamble to the proposed rule, and commenters' assertions do not cause us to revisit these issues. The commenter is also incorrect in suggesting that a change in interpretation is per se invalid and provided no support for that position. *See National Cable & Telecommunications Ass'n, et al.,* v. *Brand X Internet Services, et al.,* 545 U.S. 967, 981 (discussing the deference provided to an Agency changing interpretations, the Court stated ''change is not invalidating, since the whole point of *Chevron* deference is to leave the discretion provided by ambiguities of a statute with the implementing Agency.'') (Internal citations and quotations omitted).

The EPA disagrees with the commenters who raise concerns about the validity of the 2000 finding because the data on which that finding was based were more than 10 years old. The EPA made the finding at that time based on the scientific and technical information available, and the finding is wholly supported by that information. In addition, even though not required to do so, the EPA has since conducted new technical analyses utilizing the best information available in 2010 as several years have passed since the 2000 finding. These new analyses confirm that HAP emissions from EGUs continue to pose a hazard to public health and the environment, even after taking into account emission reductions that have occurred since 2000 from promulgated rules, settlements, and consent decrees. *See* 76 FR 24991.

Contrary to the commenter's assertion, the EPA did not violate CAA section 307(d) by not providing a notice and comment opportunity before making the December 2000 appropriate and necessary finding. One commenter challenged EPA's 2000 finding and listing on the same grounds, and the D.C. Circuit dismissed the case because CAA section 112(e)(4) clearly states that listing decisions cannot be challenged until the Agency issues final emission standards for the listed source category. *See UARG* v. *EPA*, 2001 WL 936363, No. 01–1074 (D.C. Cir. July 26, 2001). The EPA has provided the public an opportunity to comment on both the 2000 finding and the 2011 analyses that support the appropriate and necessary determination as part of the proposed rule, and anyone may challenge the listing in the D.C. Circuit in conjunction with a challenge to this final rule. The commenters could have also commented on the CAA section 112(n)(1) (*e.g.*, the Utility Study and the Mercury Study) studies in 2000 as they were included in the docket, but EPA is not aware of any comments on those studies. In any case, these studies were peer reviewed and considered the best information available at that time. The EPA has fully complied with the rulemaking requirements of CAA section 307(d).

The EPA also disagrees with the commenters' characterization of the *New Jersey* case. The D.C. Circuit did not say, as one commenter suggested, that EPA is not able to consider additional information that is collected after the 2000 finding; instead, the Court stated that EPA could not revise its appropriate and necessary finding and remove EGUs from the CAA section 112(c) list without complying with the delisting provisions of CAA section 112(c)(9). *See New Jersey*, 517 F.3d at 582–83. The EPA also disagrees with the commenter's assertion that EPA disregarded EO 12866 when making the 2000 finding. As stated in the Federal Register notice, the 2000 finding did not impose regulatory requirements or costs and was reviewed by the Office of Management and Budget (OMB) in accordance with the EO.[76]

2. New Technical Analyses

a. General Comments on New Technical Analyses

Comment: Several commenters stated that the new analyses, including the risk assessments and technology assessments, confirm that it remains appropriate and necessary to regulate U.S. EGU HAP under CAA section 112. These commenters stated that the new analyses provide even more support than the risk and technology information available at the time the 2000 finding was made, including information on further developed emissions control technology, proven and cost-effective control of acid gases using trona and dry sorbent injection, stabilized natural gas prices that makes fuel switching and switching dispatch to underutilized combined cycle plants more feasible, more information on ecosystem impacts from HAP, ''hotspots'' from the deposition of Hg around EGUs, the potential for re-emission of Hg, updated emissions data and future projections of HAP emissions, and modern air pollution modeling tools. One commenter states affordable control technology has been in use in this sector for 10 to 40 years, and studies on EGU-attributable Hg hazard has undergone two in-depth EPA reviews, as well as a review by the NAS. Several commenters claimed that regulating U.S. EGUs is appropriate and necessary to protect public health based on information provided in the new technical analyses. These commenters acknowledged the substantial reductions in HAP from recent regulations and new studies that confirm serious health risks from HAP exposure. One commenter stated that new studies show higher risks to fetuses than previously estimated, increasing the potential for neurodevelopmental effects in newborns. One commenter noted that EGUs are a major source of HAP, including HCl, HF, As, antimony, Cr, Ni, and selenium, all of which adversely affect human health. The commenter stated that because of these health effects, the EPA has ample evidence to support a determination

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[76] 65 FR 79831.

that non-Hg HAP emissions present a risk to human health.

Other commenters disagreed that the new analyses confirm that it remains appropriate and necessary to regulate U.S. EGUs. One commenter claims that EPA tried to use the new technical analyses to provide retroactive justification for the 2000 finding, which only found ''plausible links'' of health effects and ''potential concerns'' of health effects of certain metal emissions, dioxins and acid based aerosols. The commenter also asserted that none of these new analyses demonstrate that EGU regulation under section 112 is necessary and appropriate.

One commenter agreed that EPA may supplement its finding with new information, analyses and arguments to reaffirm the 2000 finding up until EPA issues final emissions standards. The commenter noted that the CAA does not freeze the finding. However, another commenter argued that EPA does not have the authority to rely on new technical analyses because the CAA requires EPA to make the finding on the basis of the Utility Study alone. According to that commenter, the EPA unreasonably stretched the language of CAA section 112 by considering new technical analyses.

Citing a report from Dr. Willie Soon that was submitted to the SAB, one commenter stated that the new technical analyses supporting the proposed rule do not conform to the Information Quality Act, which requires that information relied on by EPA be accurate, reliable, unbiased, and presented in a complete and unbiased manner.

Response: The EPA agrees with the commenters that state that the new technical analyses (*e.g.*, the risk assessments and technology assessment) confirm the 2000 finding and disagrees with the commenters that state otherwise. The EPA also agrees with the commenters that the 2000 finding was valid at the time it was made based on the CAA section 112(n)(1) studies and other information available to the Agency at that time. Furthermore, the EPA agrees with commenters that the final rule will lead to substantial reductions in HAP emissions from EGUs, that control of the HAP is estimated to lead to public health and environmental benefits as discussed in the RIA, that Hg emissions from U.S. EGUs pose a hazard to public health, and that non-Hg HAP emissions from EGUs pose a hazard to public health.

Although these new analyses were not required, the EPA agrees with the commenters that stated that EPA is authorized to conduct additional analyses to confirm the 2000 finding. The EPA disagrees with the commenter's assertion that the Agency is not authorized to consider new information and at the same time unable to use the information available in 2000 because, according to the commenter, that information is ''stale.'' Under this theory, the Agency could not ever make an appropriate and necessary finding prospectively, thereby excusing the Agency from its obligations to protect public health and the environment because it did not diligently act in undertaking its statutory responsibility to establish CAA section 112(d) standards within two years of listing EGUs. *See* CAA section 112(c)(5). This is an illogical result that finds no basis in the statute. The EPA also disagrees with the commenter's assertion that EPA may not consider new analyses conducted after the Utility Study in determining whether it is appropriate and necessary to regulate EGUs under section 112 for the reasons set forth in the preamble to the proposed rule.[77]

The EPA disagrees with the commenter's implication that EPA conducted the new analyses because of alleged flaws in the 2000 finding. As explained in detail in the preamble to the proposed rule, the 2000 finding was wholly valid and reasonable based on the information available to the Agency at that time, including the Utility Study. Further, the EPA maintains that had it complied with the statutory mandate to issue CAA section 112(d) standards within two years of listing EGUs, the EPA would likely have declined to conduct new analyses. The EPA conducted new analyses because over 10 years had passed since the 2000 finding, and EPA wanted to evaluate HAP emissions from U.S. EGUs based on the most accurate information available, though the Agency was not required to reevaluate the 2000 finding. In conducting the new analyses, the EPA used this updated information to further support the finding.

The EPA strongly disagrees with the commenter that stated that EPA failed to conform to the Information Quality Act. The EPA used peer reviewed information and quality-assured data in all aspects of the technical analyses used to support the appropriate and necessary finding supporting this regulation. In addition, the EPA submitted the Hg Risk TSD to the SAB for peer review, which ''supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs.''[78] The SAB received the comments from Dr. Willie Soon, and had those comments available for consideration in their deliberations regarding the Hg risk analysis. The SAB specifically supported elements of the analysis criticized by Dr. Willie Soon regarding the use of the EPA RfD as a benchmark for risk and the connection between Hg emissions from U.S. EGUs and MeHg concentrations in fish. In addition, the risk assessment methodology for the non-Hg case studies is consistent with the methodology that EPA uses for assessments performed for Risk and Technology Review rulemakings, which underwent peer review by the SAB in 2009.[79] During the public comment period, the EPA also completed a letter peer review of the methods used to develop inhalation cancer risk estimates for Cr and Ni compounds, and those reviews were generally supportive. See above description of this peer review. For the final rulemaking, the EPA revised both risk assessments consistent with recommendations from the peer reviewers. The EPA relies on the SAB's review of the quality of the information supporting the analytical results. Accordingly, contrary to the commenters' assertions, the EPA acted consistently with the Information Quality Act as well as EPA's and OMB's peer review requirements.

b. Hg Emissions Estimates

1. Hg Emissions From EGUs

Comment: The commenters addressed the 2005 and 2016 emissions estimates for Hg and expressed concern that inaccuracies in these emissions estimates result in overestimates of risks from Hg deposition. Further, commenters compared EPA's 2010 estimate and 2016 estimate, and stated that it is not possible for 29 tons to be a correct inventory total for Hg emissions in both years given expected reductions from CSAPR. In addition, commenters specifically commented on assumptions included in the Integrated Planning Modeling (IPM), including a concern that Hg speciation factors used by IPM overestimate emissions in 2016. Other commenters noted that EGU sources are the predominant source of U.S. anthropogenic Hg emissions, particularly the oxidized and particulate forms of Hg that are of primary concern for Hg deposition.

Response: The EPA disagrees with commenters' assertions that the EPA's

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[77] 76 FR 24988.

[78] U.S. EPA–SAB, 2011.

[79] U.S. EPA–SAB, 2010.

emissions estimates overestimate risk. While EPA agrees that the 2005 Hg emissions may be overestimated, such an overestimate in 2005 would actually lead to an underestimate of risk in 2016 and not an overestimate of risk, as claimed by the commenter, because the ratio approach used by EPA to scale fish tissue data would underestimate risk if 2005 Hg estimates were overestimated. Since the 2005 emissions are not used as a starting point for 2016 emissions from IPM, any 2005 overestimate does not affect the 2016 emissions levels. The 2016 emissions are computed by IPM based on forecasts of demand, fuel type, Hg content of the fuel, and the emissions reductions resulting from each unit's configurations. *See* IPM Documentation for further information, which is available in the docket. No commenter has provided any evidence that the IPM 2016 emissions projection methodology resulted in an overestimate.

The EPA acknowledges that the current Hg emissions estimate would not be the same as the 2016 Hg emissions estimate given that compliance with CSAPR is anticipated to have some Hg co-benefits. For this reason, the EPA reflected emission reductions anticipated from CSAPR in the Hg deposition modeling for 2016 in the Hg Risk TSD. In the final rule, the EPA revised the estimate of Hg emissions remaining from U.S. EGUs in 2016, which includes additional emission reductions anticipated from the final CSAPR. The revised estimate shows that U.S. EGUs would emit 27 tons of Hg in 2016. Although EPA does not use the current Hg emissions estimates in any of the risk calculations, the EPA estimates that current Hg emissions are 29 tons. Conclusions about the trend between current emissions and emissions in 2016 are limited by the fact that different methods were used to compute the two estimates, as fully explained in the revised Emissions Overview memo in the docket.

The EPA disagrees with the commenter's assertion that incorrect Hg emission factors result in incorrect 2016 emissions. The 2016 projected Hg emissions are not based on emissions factors. The 2016 Hg emissions are computed by the IPM based on forecasts of demand, fuel type, Hg content of the fuel, and the emissions reductions resulting from each unit's configurations. The speciation factors referenced by the commenter provide a basis for the speciation of total projected Hg emissions into particulate, divalent gaseous, and elemental species, and do not impact the total amount of Hg emissions.

The EPA agrees with commenters who noted that EGU sources are the predominant source of U.S. anthropogenic Hg emissions, and in particular the oxidized and particulate forms of Hg that are of primary concern for Hg deposition.

2. Global Hg Emissions

Comment: Several commenters stated that predicted Hg deposition relies heavily on the amount of gaseous elemental Hg used to define the boundary and initial conditions of a model, e.g., the Hg that enters the U.S. from outside the U.S. boundaries. The commenters asserted that this is especially important because Hg emissions from Asia—the region immediately upwind of North America that affects U.S. Hg deposition significantly and also affects it the most compared to other regions—are expected to continue to increase.[80] [81] [82] [83] [84] [85] According to the commenter, this would affect the amount of Hg in the boundary and initial conditions. The commenters claim that EPA's modeling did not account for these emission changes, thus leading to an overestimate of U.S. EGU-attributable deposition in 2016.

Several commenters noted that Hg emissions from U.S. EGUs are small when compared to global Hg emissions totals and natural sources within the U.S. These commenters used a variety of information to support alternative conclusions about the necessity to control U.S. EGU emissions to reduce Hg risk: global Hg emissions inventories, global and regional photochemical modeling research, and observation-based assessments. A commenter stated that EPA has not acknowledged the dramatic decline in Hg emissions from U.S. EGUs since the late 1990s (approximately 50 percent) to the current level or consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources, natural (such as fires) and human-caused.

Response: The EPA disagrees that boundary and initial conditions used in modeling Hg deposition need adjustment for several reasons. First, the EPA does not use the first 10 days of the modeling simulation in the analysis, which is more than sufficient to remove the influence of initial conditions on Hg deposition estimates.[86] Second, it is difficult to accurately characterize the speciation of Hg that flows into the U.S. from other countries due to the lack of data near the boundaries of the modeling domain. Third, the boundary inflow for the CMAQ Hg modeling used in the Hg deposition modeling are based on a global model GEOS–CHEM simulation using a 2000 based global inventory.[87] A recently published comparison of global Hg emissions by continent for 2000 and 2006 found that total Hg emissions from Asia (and Oceania) total 1,306 Mg/yr in 2000 and 1,317 Mg/yr in 2006.[88] The EPA has determined that because the Asian Hg emissions estimated in this study are nearly constant between 2005 and 2006, any adjustments to the boundary conditions or adjustments to modeled Hg deposition would be invalid and inappropriate. Recent research has shown that ambient Hg concentrations have been decreasing in the northern hemisphere since 2000.[89] Because emissions from Asia have not appreciably changed between 2000 and 2006 and ambient Hg concentrations have been decreasing, ENVIRON's analysis contains incorrect assumptions and we need not address them further. For these reasons and the large uncertainties surrounding projected Hg

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[80] Jaffe D., Prestbo E., Swartzendruber P., Weiss-Penzias P., Kato S., Takami A., Hatakeyama S., Kajii Y., 2005. ''Export of Atmospheric Mercury From Asia,'' *Atmospheric Environment*, 39, 3029–3038.

[81] Jaffe D., Strode S., 2008. ''Fate and Transport of Atmospheric Mercury From Asia,'' *Environmental Chemistry*, 5, 121.

[82] Pacyna E.G., Pacyna J.M., Sundseth K., Munthe J., Kindbom K., Wilson S., Steenhuisen F., Maxson P., 2010. ''Global Emission of Mercury to the Atmosphere From Anthropogenic Sources in 2005 and Projections to 2020,'' *Atmospheric Environment*, 44, 2487–2499.

[83] Pirrone N., Cinnirella S., Feng X., Finkelman R.B., Friedli H.R., Leaner J., Mason R., Mukherjee A.B., Stracher G.B., Streets D. G., Telmer K., 2010. ''Global Mercury Emissions to the Atmosphere From Anthropogenic and Natural Sources,'' *Atmospheric Chemistry and Physics*, 10, 5951–5964.

[84] Streets, D.G., Zhang, Q., Wu, Y., 2009. ''Projections of Global Mercury Emissions in 2050.'' *Environmental Science & Technology* 43, 2983–2988.

[85] Weiss-Penzias P., Jaffe D., Swartzendruber P., Dennison J.B., Chand D., Hafner W., Prestbo E., 2006. ''Observations of Asian Air Pollution in the Free Troposphere at Mt. Bachelor Observatory in the Spring of 2004,'' *Journal of Geophysical Research*, 110, D10304.

[86] Pongprueksa, P., Lin, C.J., Lindberg, SE., Jang, C., Braverman, T., Bullock, O.R., Ho, T.C., Chu, H.W., 2008. ''Scientific Uncertainties in Atmospheric Mercury Models III: Boundary and Initial Conditions, Model Grid Resolution, and Hg (II) Reduction Mechanism.'' *Atmospheric Environment* 42, 1828–1845.

[87] Selin, NE., Jacob, D.J., Park, R.J., Yantosca, R.M., Strode, S., Jaegle, L., Jaffe, D. 2007. ''Chemical Cycling and Deposition of Atmospheric Mercury: Global Constraints From Observations.'' *Journal of Geophysical Research-Atmospheres* 112.

[88] Streets *et al.,* 2009.

[89] Slemr, F., Brunke, E.G., Ebinghaus, R., Kuss, J., 2011. ''Worldwide Trend of Atmospheric Mercury Since 1995.'' *Atmospheric Chemistry and Physics* 11, 4779–4787.

global inventories, the EPA concludes that the most appropriate technical choice is to keep the Hg boundary conditions the same between the 2005 and 2016 simulations.

The EPA also disagrees with the commenters' assertion that EPA has not acknowledged the decline in Hg emissions for the U.S. EGUs since the late 1990s. The EPA analyzed historical, current, and future projected Hg emissions from the power generation sector, as cited in the preamble to the proposed rule. The EPA also disagrees with the commenters' assertions that EPA failed to consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources. As noted in the Hg Risk TSD, the EPA modeled Hg emissions from U.S. and non-U.S. anthropogenic and natural sources to estimate Hg deposition across the country. The EPA also determined the contribution of Hg emissions from U.S. EGUs to total Hg deposition in the U.S. by running modeling simulations for 2005 and 2016 with Hg emissions from U.S. EGUs set to zero. Based on the Hg Risk TSD, Hg emissions from U.S. EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition.

The commenters suggest that Hg emissions from U.S. EGUs represent a limited portion of the total Hg emitted worldwide, including anthropogenic and natural sources. While EPA acknowledges that Hg emissions from U.S. EGUs are a small fraction of the total Hg emitted globally, it views the environmental significance of Hg emissions from U.S. EGUs and other domestic sources as a more germane consideration. Mercury is emitted from EGUs in three forms. Each form of Hg has specific physical and chemical properties that determine how far it travels in the atmosphere before depositing to the landscape. Although gaseous oxidized Hg and particle-bound Hg are generally local/regional Hg deposition concerns, all forms of Hg may deposit to local or regional watersheds. U.S. coal-fired power plants account for over half of the U.S. controllable emissions of the quickly depositing forms of Hg. Although emissions from international Hg sources contribute to Hg deposition in the U.S., the peer reviewed scientific literature shows that Hg emissions from U.S. EGUs in the U.S. significantly enhance Hg deposition and the response of ecosystems in the U.S. [90] [91] [92] [93]

c. Hg Deposition Modeling

1. General Comments on Deposition Modeling

Comment: Several commenters stated that according to the ENVIRON report, the EPA overestimated U.S. EGU-attributable Hg deposition by 10 percent on average (and up to 41 percent in some areas). The commenters claim this overestimation is the result of boundary condition treatment, the exclusion of U.S. fire emissions,[94] and Hg plume chemistry approach. In addition, one commenter referenced the same ENVIRON report and stated that before implementation of controls required by the proposed rule, areas with relatively high EGU-attributable Hg deposition (one-fifth or more of total deposition) in 2016 constitute less than 0.25 percent of the continental U.S. area, and only three grid cells have EGU contributions exceeding half of total deposition.

Another commenter suggested that current research shows that models of Hg atmospheric fate and transport overestimate the local and regional impacts of some anthropogenic sources, such as U.S. EGUs. Thus, according to the commenter, calculated contributions to Hg deposition and fish tissue MeHg levels from these sources represent upper bounds of actual contributions,[95] [96] and EPA should present results as estimates of lower and upper bound limits.

Response: The EPA disagrees with the information presented by ENVIRON. The ENVIRON report is based on the misapplication of multiple incommensurate modeling studies and false premises which include the incorrect notion that the boundary conditions are over-estimated and the idea that EPA should use in-plume chemistry that has not been explicitly characterized and peer reviewed. Reactions that may reduce gas phase oxidized Hg in plumes have not been explicitly identified in literature. Recent studies in central Wisconsin and central California suggest the opposite may happen; elemental Hg may be oxidized to Hg(II) in plumes.[97] [98] Better field study measurements and specific reaction mechanisms need to be identified before making conclusions about potential Hg in-plume chemistry or applying surrogate reactions in regulatory modeling. The possibility that Hg(0) is oxidized to Hg(II) in plumes suggests coal-fired power plant Hg contribution inside the U.S. may be underestimated in EPA modeling.

The EPA asserts that the numbers suggested by the commenter are inaccurate, as it is not appropriate to adjust EPA's deposition estimates based on previous Hg modeling done with older Hg chemistry, in-plume reactions that have not been explicitly identified, and erroneous adjustments to Hg boundary inflow. Recent research has shown that ambient Hg concentrations have been decreasing in the northern hemisphere since 2000.[99] The EPA declines to revise this analysis as commenter suggests for several reasons, including available evidence indicates that emissions from China have not appreciably changed between 2000 and 2006 [100] and ambient Hg concentrations have decreased, the commenter inappropriately comingled out–of-date Hg modeling simulations with EPA results, and ENVIRON's analysis has not undergone any scientific peer review and presents information with incorrect assumptions as noted in this response.

The EPA also disagrees with the commenter's interpretation of the applicability of wildfire Hg emissions to

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[90] Caffrey *et al.,* 2010.

[91] Driscoll, C. T., Han, Y.-J., Chen, C. Y., Evers, D. C., Lambert, K. F., Holsen, T. M., *et al.,* (2007). ''Mercury Contamination in Forest and Freshwater Ecosystems in the Northeastern United States.'' *BioScience*, 57(1).

[92] Keeler, G.J., Landis, M.S., Norris, G.A., Christianson, E.M., Dvonch, J.T., 2006. ''Sources of Mercury Wet Deposition in Eastern Ohio, USA.'' *Environmental Science & Technology* 40, 5874–5881.

[93] White, E.M., Keeler, G.J., Landis, M.S., 2009. ''Spatial Variability of Mercury Wet Deposition in Eastern Ohio: Summertime Meteorological Case Study Analysis of Local Source Influences.'' *Environmental Science & Technology* 43, 4946–4953.

[94] Finley, B.D., Swartzendruber, P.C., Jaffe, D.A., 2009. ''Particulate Mercury Emissions in Regional Wildfire Plumes Observed at the Mount Bachelor Observatory.'' *Atmospheric Environment* 43, 6074–6083.

[95] Seigneur, C., Lohman, K., Vijayaraghavan, K., Shia, R.L., 2003. ''Contributions of global and regional sources to mercury deposition in New York State.'' Environmental Pollution 123, 365–373.

[96] Seigneur, C., Vijayaraghavan, K., Lohman, K., Karamchandani, P., Scott, C., 2004. ''Modeling the atmospheric fate and transport of mercury over North America: power plant emission scenarios.'' *Fuel Processing Technology* 85, 441–450.

[97] Kolker, A., Olson, M.L., Krabbenhoft, D.P., Tate, M.T., Engle, M.A., 2010. ''Patterns of mercury dispersion from local and regional emission sources, rural Central Wisconsin, USA.'' *Atmospheric Chemistry and Physics* 10, 4467–4476.

[98] Rothenberg, SE., McKee, L., Gilbreath, A., Yee, D., Connor, M., Fu, X.W., 2010. ''Wet deposition of mercury within the vicinity of a cement plant before and during cement plant maintenance.'' *Atmospheric Environment* 44, 1255–1262.

[99] Slemr *et al.,* 2011.

[100] Streets *et al.,* 2009.

[101] Finley *et al.,* 2009.

this assessment. Finley *et al.,* (2009)[101] suggests caution when using their field data to make assumptions about Hg(p) emissions from wildfires; the estimated particulate Hg emissions from wildfires is based on one field site with a limited sample size, and the assumptions made (such as the observed Hg(p) to carbon monoxide ratios at this location) may not be valid on a broader scale.[102] Mercury emissions from wildfires are a re-volatilization of previously deposited Hg.[103] Given that electrical generating power plants are currently and historically have been among the largest Hg-emitting sources, the inclusion of wildfire emissions in a modeling assessment would necessarily increase the contribution from this emissions sector.

The EPA disagrees with the assertion that EPA failed to consider the relative magnitude of Hg emissions from U.S. EGUs compared to other sources and disagrees with the interpretation of EGU deposition presented in the ENVIRON report. As noted in the Hg Risk TSD, the EPA modeled Hg emissions from U.S. and non-U.S. anthropogenic and natural sources to estimate Hg deposition across the country. The EPA also determined the contribution of Hg emissions from U.S. EGUs to total Hg deposition in the U.S. by running modeling simulations for 2005 and 2016 with Hg emissions from U.S. EGUs set to zero. Hg emissions from U.S. EGUs pose a hazard to public health based on the total of 29 percent of modeled watersheds potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. The ENVIRON report provides no risk analysis of EGU contribution.

The EPA disagrees that research[104][105] presented by the commenter shows that U.S. EGU impacts are over-estimated. The commenter's references do not support this statement. The references provided by the commenter are based on Hg modeling that uses models that are no longer applied and that are based on out-dated Hg chemistry and deposition assumptions. Given the advances in Hg modeling since the early 2000s, the EPA does not believe an upper and lower bound estimate is necessary.

2. Chemical Reactions

Comment: Several commenters stated that the CMAQ modeling fails to account for the chemical reduction of gaseous ionic Hg to elemental Hg that may occur in EGU plumes. The commenters noted that EPA did not use the Electric Power Research Institute's (EPRI) Advanced Plume-in-Grid Treatment, which includes a surrogate reaction to reduce gaseous ionic Hg to elemental Hg inside plumes. Multiple commenters claimed that the reduction of reactive gaseous Hg to gaseous elemental Hg has been reported in power plant plumes and that supporting data include atmospheric concentrations of speciated Hg measured downwind of power plant stacks at ground-level monitor sites and dispersion model predictions.[106][107] A detailed description of various plume measurement studies is provided in EPRI Comments, Section 3.4: Plant Bowen, Georgia, Plant Pleasant, Wisconsin, and Plant Crist, Florida. One commenter believed the impact of grid resolution (12 km sized grid cells) on the CMAQ modeling was not appropriately addressed by EPA. Their concerns due to grid resolution include the notion that a source's emissions will be averaged over the entire grid cell. According to the commenter, such averaging causes an artificially fast dilution that smoothes out areas of high and low deposition, which may limit the ability of the model to simulate smaller areas of localized high deposition. This commenter believed that using the APT would address these issues.

Response: The EPA disagrees with the commenters' claims that oxidized Hg chemically reduces to elemental mercury within the plume. There is no evidence of these chemical reactions in the scientific literature. The references cited by the commenters are from non-peer reviewed reports and conference proceedings. The EPA does not consider information presented at conferences or industry reports to be peer reviewed literature, and consideration of oral presentation material would be inappropriate. Further, even these cited references do not provide sufficient information for incorporating the supposed reactions into the modeling (*e.g.*, specific chemical reactions, reaction rates, etc.); rather, the cited references only suggest that oxidized gas phase Hg could be reduced and postulate a possible pathway.

Recent studies in central Wisconsin and central California suggest the opposite may happen; elemental Hg may be oxidized to Hg(II) in plumes.[108][109] Better field study measurements and specific reaction mechanisms need to be identified before making conclusions about potential Hg in-plume chemistry or applying surrogate reactions in regulatory modeling. Currently, models such as Advanced Plume Treatment (APT) use a surrogate reaction for the potential reactive gas phase Hg reduction that may or may not occur in plumes.[110] Reactions that may reduce gas phase oxidized Hg in plumes have not been explicitly identified in literature. The application of potentially erroneous in-plume chemistry that is a fundamental component of APT would be inappropriate. In addition, the APT is not available in the most recent version of CMAQ. It would be inappropriate for EPA to apply an out of date photochemical model with in-plume chemistry that has not been shown to exist.

The EPA agrees with the commenter that the CMAQ modeling with 12 km grid resolution may provide a lower bound estimate on EGU contribution as higher impacts using finer grid resolution are possible. The commenter's assertion that EGU impacts are likely higher further supports the final conclusions of the exposure modeling assessment. The EPA notes that the application of a photochemical model at a 12 km grid resolution for the entire continental U.S. is more robust in terms of grid resolution and scale that anything published in literature and represents the most advanced modeling platform used for a national Hg deposition assessment.

3. Modeled Deposition Compared to Measured Deposition

Comment: Multiple commenters expressed dissatisfaction related to EPA's model performance evaluation of CMAQ estimated Hg deposition. The commenters stated that EPA failed to evaluate the CMAQ model against real-world measurements and that EPA fails to provide first-hand information on wet and dry deposition processes. The commenters also stated that EPA needs

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[100] Streets *et al.,* 2009.

[101] Finley *et al.,* 2009.

[102] *Id.*

[103] Wiedinmyer, C., Friedli, H., 2007. "Mercury emission estimates from fires: An initial inventory for the United States." *Environmental Science & Technology* 41, 8092–8098.

[104] Seigneur *et al.*, 2003.

[105] Seigneur *et al.*, 2004.

[108] Kolker *et al.,* 2010.

[109] Rothenberg *et al.*, 2010.

[110] Vijayaraghavan, K., Seigneur, C., Karamchandani, P., Chen, S.Y., 2007. "Development and application of a multipollutant model for atmospheric mercury deposition." *Journal of Applied Meteorology and Climatology* 46, 1341–1353.

to assess how predicted values of deposition compare to Mercury Deposition Network (MDN) data and how predicted values of ambient speciated Hg concentrations compare to measurement networks like AMNet and SEARCH. In addition, commenters stated that EPA used highly aggregated performance metrics comparing model estimates to observations that they believe result in a degraded and lenient operational evaluation of the modeling system. A commenter suggested that EPA's model performance provides no confidence for the intended purpose of estimating deposition near point sources. One commenter simply noted that EPA's model over-estimated total Hg wet deposition at MDN monitors. Finally, several commenters noted that EPA presented a negative modeled wet deposition total in the Air Quality Modeling TSD, which is physically impossible.

Response: EPA agrees with the commenters that the negative estimate for wet deposition in the Air Quality Modeling TSD was an error. This error reflected an incorrect calculation in the post-processing of model and observation pairs that only influenced the calculation of model performance metrics. The error has been fixed, and the model performance metrics in the revised Air Quality Modeling TSD have been updated. This error did not affect Hg deposition. In response to comments, the EPA provided additional model performance evaluation by season to the revised Air Quality Modeling TSD. In addition, in response to comments, the EPA also included model performance evaluation for total Hg wet deposition for the 36 km modeling domain in the revised Air Quality Modeling TSD.

The EPA disagrees that it did not conduct an assessment comparing CMAQ total Hg wet deposition estimates to MDN data. The Air Quality Modeling TSD clearly shows a comparison of CMAQ estimated total Hg wet deposition with MDN data for the entire length of the modeling period. The CMAQ wet deposition of Hg has been and will continue to be extensively evaluated against MDN sites.[111] There is no dry deposition monitoring network, which precludes evaluating CMAQ dry deposition processes. The EPA disagrees that an evaluation of ambient speciated Hg against routine monitor networks such as AMNet or SEARCH would be useful for this particular modeling application. The AMNet Hg network did not exist in 2005, which is EPA's baseline model simulation time period, and the SEARCH network started making preliminary measurements of Hg at one or two sites in 2005. In addition, measurement artifacts related to gaseous oxidized Hg are difficult to quantify and make direct comparison to model estimates problematic.[112] Considering the problems associated with TEKRAN measurements of ambient Hg and the sparse nature of routine measurements in the U.S., the EPA did not compare ambient Hg against model estimates.

The EPA disagrees that the model performance presented in the air quality TSD is insufficient. The EPA asserts that the model performance evaluation is generally similar to the level of model performance presented in literature. One commenter presented the results of several Hg modeling studies as providing information that the commenter believes to be relevant for this assessment in terms of model performance metric estimation and the level of model performance evaluation shown for assessments modeling Hg near point sources. For example, one cited study titled ''Modeling Mercury in Power Plant Plumes'' models near-source Hg chemistry from U.S. EGUs, but provides absolutely no information about model performance evaluation.[113]

Another commenter identified two studies as supposedly having Hg modeling results that are applicable to EPA's analysis.[114] [115] These studies present similar model performance metrics as EPA. The EPA disagrees that the Agency used ''highly aggregated performance metrics'' that result in degraded and lenient model evaluation. The studies presented [116] [117] as relevant for point source mercury modeling use an approach to aggregate the operational performance metrics across many monitor locations as did EPA; however, these articles calculate long term annual averages of modeled and observed total Hg wet deposition before estimating performance metrics. It is common practice to pair modeled estimates and observations in space and time (weekly in this case) and estimate performance metrics, then average all the metrics together. The latter is the approach taken by the EPA and should have been taken by the studies presented by the commenter. The EPA used a more stringent approach to match observations and predictions and aggregation of operational model performance. The EPA agrees that the commenter accurately restated total wet deposition model performance information provided by the EPA in the Air Quality Modeling TSD. To provide context, other Hg modeling studies show a positive bias for annual total Hg wet deposition.[118] [119] An annual Hg modeling application done by ENVIRON [120] and the Atmospheric and Environmental Research for Lake Michigan Air Directors Consortium show seasonal average normalized bias between 70 and 158 percent and seasonal average normalized error between 72 and 503 percent.[121] These results indicate a very large over-estimation tendency. The model performance shown by EPA is consistent with other long-term Hg modeling applications.

4. Excess Local Deposition From Hg Emissions From U.S. EGUs (Deposition Hotspots)

Comment: One commenter stated that reducing Hg will benefit local environments. The commenter stated that a 2007 study confirmed the presence of Hg ''hotspots'' downwind from coal-fired power plants and confirmed that coal-fired power plants within the U.S. are the primary source of Hg to the Great Lakes and the Chesapeake Bay.[122] The commenter also stated that the study is consistent with a major Hg deposition study conducted

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[111] Bullock, O.R., Atkinson, D., Braverman, T., Civerolo, K., Dastoor, A., Davignon, D., Ku, J.Y., Lohman, K., Myers, T.C., Park, R.J., Seigneur, C., Selin, NE., Sistla, G., Vijayaraghavan, K., 2009. ''An analysis of simulated wet deposition of mercury from the North American Mercury Model Intercomparison Study.'' *Journal of Geophysical Research-Atmospheres* 114.

[112] Lyman, S.N., Jaffe, D.A., Gustin, M.S., 2010. ''Release of mercury halides from KCl denuders in the presence of ozone.'' *Atmospheric Chemistry and Physics* 10, 8197–8204.

[113] Lohman *et al.,* 2006.

[114] Seigneur, C., Lohman, K., Vijayaraghavan, K., Jansen, J., Levin, L., 2006. ''Modeling atmospheric mercury deposition in the vicinity of power plants.'' *Journal of the Air & Waste Management Association* 56, 743–751.

[115] Vijayaraghavan, K., Karamchandani, P., Seigneur, C., Balmori, R., Chen, S.–Y., 2008. ''Plume-in-grid modeling of atmospheric mercury.'' *Journal of Geophysical Research-Atmospheres* 113.

[116] Seigneur, C., Lohman, K., Vijayaraghavan, K., Jansen, J., Levin, L., 2006. ''Modeling atmospheric mercury deposition in the vicinity of power plants.'' *Journal of the Air & Waste Management Association* 56, 743–751.

[117] Vijayaraghavan, K., Karamchandani, P., Seigneur, C., Balmori, R., Chen, S.-Y., 2008. ''Plume-in-grid modeling of atmospheric mercury.'' *Journal of Geophysical Research-Atmospheres* 113.

[118] *Id.*

[119] Vijayaraghavan *et al.,* 2007.

[120] Yarwood, G, Lau, S., Jia, Y., Karamchandani, P., Vijayaraghavan, K. 2003. Final *Report: Modeling Atmospheric Mercury Chemistry and Deposition with CAMx for a 2002 Annual Simulation.* Prepared for Wisconsin Department of Natural Resources. *http://www.gypsymoth.wi.gov/air/toxics/mercury/hg_X97579601_appB.pdf.*

[121] Yarwood *et al.*, 2003.

[122] Evers, David C. *et al.,* 2007. ''Biological Mercury Hotspots in the Northeastern United States and Southeastern Canada,'' *Bioscience.* Vol. 57 No. 1. p. 29.

by the EPA and the University of Michigan that concluded that approximately 70 percent of Hg wet deposition resulted from local fossil fuel emissions in the region.[123]

One commenter agreed with the Agency's assessment of the potential for deposition ''hotspots'' that shows that Hg deposition near EGUs can be three times as large as the regional average. The commenter stated that this excess Hg deposition would substantially increase the health and environmental risks associated with emissions at these sites. The same commenter also stated that EPA applied a conservative methodology to quantify near-source Hg deposition. The commenter stated that maximum excess local Hg deposition may be significantly underestimated by averaging high deposition sites downwind of an EGU in the direction of prevailing winds with lower excess deposition at locations close to but frequently upwind of the facility. The same commenter suggests that had EPA used CMAQ and individual 12x12 km^2 grid cells to quantify local deposition, the model could increase the excess Hg deposition at these locations significantly and place them at even greater risk of adverse health and environmental effects of HAP from U.S. EGUs.

One commenter stated that the Hubbard Brook Research Foundation issued a report in 2007 that identified five Hg hotspots, one of which was in the Adirondack Park, along with four suspected hotspots.[124] The commenter stated that this study also provides a good description of the impacts of Hg on the Common Loon, which is a symbol of a healthy Adirondack environment.

One commenter stated that there is there is no evidence of Hg hotspots due to local deposition associated with coal-fired power plants. According to the commenter, the EPA's use of a 50 km radius to calculate hotspots is flawed. The commenter stated that modeling studies show that deposition of Hg emitted from power plants is not confined to a 50-km radius around the plants and that most emissions from power plants travel beyond 50 km.[125]

Several commenters stated that the EPA does not adequately define hotspots in this proposed rule. Those same commenters cited a previous EPA definition of hotspots as ''a waterbody that is a source of consumable fish with MeHg tissue concentrations, attributable solely to utilities, greater than EPA's MeHg water quality criterion of 0.3 mg/kg'' (milligrams per kilogram).[126] The same commenters stated that it is unclear why EPA changed from defining a hotspot by fish tissue MeHg concentration to defining a hotspot by depositional excess. Two commenters suggested that a Hg hotspot is a specific location that is characterized by elevated concentrations of Hg exceeding a well-established criterion, such as a reference concentration (RfC) when compared to its surroundings. Those same commenters stated that identifying Hg hotspots should not be constrained to locations where concentrations can be attributed to a single source or sector.[127] One of those two commenters noted that others have defined ''hotspots as a spatially large region in which environmental concentrations far exceed expected values, with such values (i.e. concentrations) being 2 to three standard deviations above the relevant mean.'' [128]

One commenter stated that Hg concentrations are not always highest at sites closest to a major source. The commenter referred to a study [129] that demonstrated that concentrations of atmospheric reactive gaseous Hg, gaseous elemental Hg, and fine particulate Hg were lower when measured 25 km from a 1,114 MW coal-fired EGU than when measured 100 km away. The commenter stated that these findings contradict the idea, implicit in EPA's hotspot analysis, that reactive gaseous Hg decreases with distance from a large point source.

One commenter provided information from a non-peer reviewed report with wet Hg deposition measurements downwind from the coal-fired power plant Crist in Pensacola, FL. The commenter stated that using the same data from these same wet deposition sites, one study [130] found that Hg wet deposition and concentrations did not differ in a statistically significant manner among these three sites and that the concentrations values were similar to those from Mercury Deposition Network (MDN) sites that are more than 50 km away from Plant Crist located along the Northern Gulf of Mexico coast.

Another commenter stated that Plant Crist installed a wet scrubber and has operated that scrubber continuously since December 2009. The commenter stated that the scrubber reduces total Hg emissions by about 70 percent and reduces emissions of reactive gaseous Hg by about 85 percent. The commenter cited a non-peer reviewed conference presentation [131] that reported changes in Hg wet deposition relative to historic measurements. The commenter stated that, taken collectively, these findings show that increased local total Hg deposition, possibly due to EGUs, and deposition changes due to changes in EGU emissions, are small.

Two commenters stated that a study by the Department of Energy (DOE) that collected and analyzed soil and vegetation samples for Hg near three U.S. coal-fired power plants—one in North Dakota, one in Illinois, and one in Texas—found no strong evidence of ''hotspots'' around these three plants.

Two commenters stated that analysis of long-term trends in Hg emissions from coal-fired EGUs and wet deposition in Florida concluded that statistical analysis does not show evidence of a significant relationship between temporal trends in Hg emissions from coal-fired EGUs in Florida and Hg concentrations in precipitation during 1998 to 2010.

Two commenters stated that the Hg Risk TSD presents no information, summary statistics, and/or actual calculations showing how excess deposition within 50 km of an EGU source is obtained. The commenters stated that by assessing only Hg deposition attributable to EGUs, the EPA fails to provide a context for all other sources of Hg deposition. The commenters stated that the Agency does not explain why deposition from the top 10 percent of EGU Hg emitters does not decline, despite substantial reductions in modeled Hg emissions from those sources between 2005 and 2016.

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[123] Cohen, *et al.,* 2004. ''Modeling the Atmospheric Transport and Deposition of Mercury to the Great Lakes,'' *Environmental Research 95,* (247–265).

[124] Driscoll, C.T., D. Evers, K.F. Lambert, N. Kamman, T. Holsen, Y-J. Han, C. Chen, W. Goodale, T. Butler, T. Clair, and R. Munson. Mercury Matters: Linking Mercury Science with Public Policy inthe Northeastern United States. 2007. Hubbard Brook Research Foundation. Science Links Publication. Vol. 1, no. 3.

[125] Seigneur *et al.,* 2006.

[126] U.S. EPA, 2005. 40 CFR Part 63 [OAR–2002–0056; FRL–7887–7] RIN 2060–AM96. *Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c).* Final rule, March 29.

[127] Evers *et al.,* 2007.

[128] Sullivan T., 2005. ''The Impacts of Mercury Emissions from coal-fired Power Plants on Local Deposition and Human Health Risk.'' Presented at the Pennsylvania Mercury Rule Workgroup Meeting, October 28.

[129] Kolker, *et al.,* 2010.

[130] Caffrey, J.M., Landing, W.M., Nolek, S.D., Gosnell, K.J., Bagui, S.S., Bagui, S.C., 2010. ''Atmospheric deposition of mercury and major ions to the Pensacola (Florida) watershed: spatial, seasonal, and inter-annual variability.'' *Atmospheric Chemistry and Physics* 10, 5425–5434.

[131] Krishnamurthy N., Landing W.M, Caffrey J.M., 2011. ''Rainfall Deposition of Mercury and Other Trace Elements to the Northern Gulf of Mexico.'' Presented at the 10th International Conference on Mercury as a Global Pollutant, Halifax, Nova Scotia, Canada, July 27.

According to the commenters this implies that the top 10 percent EGUs may have approximately as much of a regional effect as a local effect.

Two commenters stated that the CMAQ model has limitations when used to predict local deposition and tends to overestimate local deposition. The commenters stated that modeling studies using either a plume model or an Eulerian model predict that 91 to 96 percent of the Hg emitted by an EGU travels beyond 50 km.[132]

Response: The EPA agrees with the commenters that stated that Hg emissions from EGUs deposit locally and regionally and contribute to excess local deposition near U.S. EGUs. The EPA acknowledges additional studies[133] cited by those commenters that corroborate EPA's conclusions. However, the EPA disagrees with those commenters' characterization of the methodology used to calculate the potential for excess local deposition. In response, the EPA has clarified the methodology in the new TSD entitled ''Technical Support Document: Potential for Excess Local Deposition of U.S. EGU Attributable Mercury in Areas near U.S. EGUs,'' which is available in the docket.

The EPA agrees that there is no generally agreed-upon definition of ''hotspot.'' As discussed in the preamble and TSD, for the purposes of the appropriate and necessary finding, the EPA determined that information on the potential for excess deposition of Hg in areas surrounding power plants would be useful in informing the finding. The EPA disagrees with some commenters who misinterpreted the intent of the Hg deposition hotspot analysis. Specifically, the analysis is not of ''Hg hotspots'', which are often defined as high Hg concentration in fish, but rather of Hg deposition hotspots, defined as excess local Hg deposition around U.S. EGUs, as clarified in the new Local Deposition TSD. Because EPA did not identify ''Hg hotspots'' of high Hg concentrations in fish, the EPA's MeHg water quality criterion of 0.3 mg/kg is irrelevant to EPA's analysis of excess local Hg deposition for this rule.

The EPA disagrees that the analysis assumes that deposition of Hg is confined to a 50-km radius around power plants. The purpose of the EPA's analysis was to evaluate whether there existed ''excess deposition of Hg in nearby locations within 50 km of EGUs that might result in Hg deposition 'hotspots'.'' As explained further in the new TSD, the EPA calculated the average EGU-attributable deposition (based on CMAQ modeling of Hg deposition) in the area 500 km around each plant and the average EGU-attributable deposition in the area 50 km around each plant. The difference between those two values is the excess local deposition around the plant. The EPA does not suggest Hg emissions from power plants stop at 50 km from the source. Some portion of EGU emissions deposit before 50 km, and some portion travels beyond 50 km. In addition, Hg disperses as it transports, so the average EGU contribution can be lower in areas beyond 50km relative to areas within 50km even though Hg emissions from EGUs are depositing into U.S. watersheds.

The EPA disagrees with some commenters' interpretation of the analysis as being focused on local deposition from all sources. In fact, the focus was on excess local deposition, rather than all local deposition. The EPA has clarified the purpose of the excess local deposition analysis in the new TSD. The EPA agrees that all EGUs add to local deposition, however, not all EGUs have local deposition that greatly exceeds regional deposition, which is the relevant question. The EPA disagrees that the DOE study referenced by the commenters attempted to assess the same analytical question as EPA's analysis. The DOE study focused on comparisons of total deposition near and far from power plants. The EPA's analysis did not focus on total Hg deposition, because as EPA acknowledges throughout its analysis, global sources of Hg deposition account for a large percentage of total Hg deposition. In addition, including global sources of Hg deposition would obscure the comparison of local and regional U.S. EGU-attributable Hg deposition. Because of regional deposition from both domestic and global sources of Hg, total Hg deposition at any location is unlikely to be highly correlated with local sources. The EPA's analysis focused on U.S. EGU-attributable Hg deposition and demonstrates that for some plants (especially those with high Hg emissions), there is local deposition of Hg that exceeds the average regional deposition around the plant.

The EPA's analysis shows heterogeneity in the amount of excess local deposition around plants. The new Local Deposition TSD shows that some plants can have local deposition that is less than the regional average deposition, suggesting that most of the Hg from those plants is transported regionally or that other EGUs in the vicinity of those plants dominate the deposition of Hg near the plants. This does not detract from the overall finding that around some power plants with high levels of Hg emissions excess local deposition is on average three times the regional EGU-attributable deposition around those plants.

The EPA disagrees that the Hg Risk TSD did not provide sufficient information regarding the excess local deposition calculation. Nonetheless, the EPA has further clarified the methodology in the new Local Deposition TSD, including further descriptions of the method used to calculate the local and regional deposition around power plants along with maps and tables of results.

The EPA disagrees with the commenters that stated that the discussion of local deposition in the Hg Risk TSD did not demonstrate that Hg deposition from the top 10 percent of EGU Hg emitters declines. Table 1 of the new Local Deposition TSD clearly shows that mean local deposition (within 50km of a plant) for the top 10 percent of emitters declines from 4.89 micrograms per cubic meter ($\mu g/m^3$) to 1.18 $\mu g/m^3$. What does not change is the percent local excess for EGU-attributable Hg deposition. This implies that while Hg deposition from EGUs is declining, there is still an excess contribution to local deposition relative to regional deposition; *e.g.*, because of dispersion, the contribution to average deposition outside 50 km from the plant is lower than the contribution to average deposition within 50 km of the plant.

The EPA disagrees that the information[134] provided by the commenter regarding the Crist plant and other coal-fired power plants in Florida is relevant to EPA's analysis of excess local deposition from U.S. EGUs because it is based on measurements of wet Hg deposition without consideration of dry Hg deposition, which can be a significant component of Hg deposition.

The EPA disagrees with the commenter regarding the interpretation of the literature related to the spatial extent of deposition of Hg emitted by U.S. EGUs. The EPA also disagrees that the peer-reviewed CMAQ model has limitations for this application or overestimates local deposition. The commenter does not provide any credible support for the assertion that grid-based models typically overestimate local deposition surrounding EGUs. The EPA maintains that the CMAQ photochemical model represents the best science currently available in simulating atmospheric

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[132] Edgerton *et al.,* 2006.

[133] Driscoll *et al.,* 2007.

[134] EPRI, 2010.

chemistry, transport, and deposition processes.

The study[135] cited by the commenter to support the notion that 91 to 96 percent of Hg emitted from power plants travels beyond 50 km is based on a photochemical transport model (the TEAM model) that does not employ current state-of-the-science and is not actively developed or updated. Furthermore, the modeling is based on grid cells that are 20 km in size, which limits generalizability to EPA modeling performed at 12 km grid resolution using a state of the science photochemical grid model. The cited modeling study ignores dry deposition of elemental Hg from all sources, an assumption that clearly limits the regional impacts from sources.[136] The methodology of this study cited by the commenter is critically flawed in that it presents no results where individual Hg emission sources are removed and the difference between the zero out simulation (where emissions from U.S. EGUs are set to zero) and the baseline model simulations are directly compared. Finally, the modeling study cited by the commenter presents an illustration of gridded total annual Hg deposition from the TEAM model for the eastern U.S. that clearly shows elevated annual total Hg deposition in the vicinity of coal-fired power plants in the Ohio River Valley and northeast Texas.

d. Hg Risk TSD

1. Assumption of Linear Proportionality in Relationship Between Changes in Hg Deposition and Changes in Fish Tissue Hg Concentrations (Mercury Maps)

Comment: Several commenters criticized EPA's assumption that changes in deposition resulting from U.S. EGU emissions of Hg will result in proportional changes in fish tissue Hg concentrations at the watershed level, as supported by the Mercury Maps modeling exercise. According to one commenter, the Mercury Maps model has limited capability to adequately determine bioaccumulation in fish. The same commenter stated that the Mercury Cycling Model (MCM) developed by EPRI is a more rigorous model that was developed expressly to evaluate the relationship between changes in atmospheric Hg deposition to waterbodies and changes in fish tissue MeHg levels.

Several commenters stated that the Mercury Maps model has many deficiencies. Those commenters stated that Mercury Maps is a static model unable to account for the dynamics of ecosystems that affect Hg bioaccumulation in fish, cannot consider non-air Hg inputs to watersheds, and assumes reductions in airborne Hg lead to proportional reductions in fish MeHg concentrations. Another commenter claimed that data that demonstrate a steady-state linear reduction in fish tissue MeHg in response to a reduction in atmospheric Hg deposition within watersheds do not exist and provided several references that they claimed show non-linear responses to changes in Hg deposition.[137] [138]

The same commenter disagreed with EPA's interpretation of Figure 2–17 in the March TSD and stated that a U.S. Geological Survey national waterway study[139] showed that sheet flow and drainage, not deposition, dominated input to the waterbodies it surveyed. The commenter stated that sheet flow and drainage could contain Hg and thus complicate the relationship that EPA asserts is linear and direct. Another commenter cited Figure 2–17 in the Hg Risk TSD as showing that there is no well-defined relationship between Hg deposition and MeHg concentrations in fish tissue on a national basis.

Several commenters provided comments related to the assumption that fish tissue Hg levels used in the analysis represent a steady-state. One commenter stated that given the demonstrated lag time in response to deposition change, it is logical to conclude that a lag time needs to be incorporated in Mercury Maps to adjust the estimation of how much fish tissue MeHg levels decrease in response to decreases in Hg deposition attributable to U.S. EGUs. According to the same commenter, the METAALICUS study shows that there is a lag time (and a non-proportional response) after 3–4 years. The same commenter noted that there are numerous factors that influence lag time including (1) watershed characteristics,[140] (2) the fact that watersheds may act as legacy sources releasing Hg when disturbed,[141] (3) the magnitude of emission reductions and subsequent changes in atmospheric deposition need to be weighed against the amount of Hg already in an ecosystem,[142] (4) the distance of an ecosystem from Hg sources,[143] and (5) the fact that Hg deposited to aquatic ecosystems becomes less available for uptake by biota over time.[144] Another commenter stated that additional Mercury Maps assumptions do not allow for considerations of lag in response to changes in: (1) Deposition, (2) legacy sources of Hg such as mining, (3) historical Hg deposition, (4) natural Hg levels in fish, (5) ecosystem dynamics over time, or (6) the relative source contributions over time. Another commenter stated that lag times need to be included in the modeling and be able to vary from watershed to watershed and sometimes even from waterbody to waterbody within a watershed. Several commenters stated that the emission rates of Hg due to U.S. sources have been decreasing for more than a decade, while emissions due to sources outside the U.S. have been increasing. For this reason, the commenter asserted that the system is not at steady-state, a basic premise of the model. Another commenter stated that while the time lag for deposition to reach a waterbody is mentioned in the Hg Risk TSD, there is no discussion of the fact that a

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[135] Seigneur *et al.*, 2006.

[136] *Id.*

[137] Harris., R.C., John W.M. Rudd, Marc Amyot, Christopher L. Babiarz, Ken G. Beaty, Paul J. Blanchfield, R.A. Bodaly, Brian A. Branfireun, Cynthia C. Gilmour, Jennifer A. Graydon, Andrew Heyes, Holger Hintelmann, James P. Hurley, Carol A. Kelly, David P. Krabbenhoft, Steve E. Lindberg, Robert P. Mason, Michael J. Paterson, Cheryl L. Podemski, Art Robinson, Ken A. Sandilands, George R. Southworth, Vincent L. St. Louis, and Michael T. TateRudd, J. W.M., Amyot M., *et al.*, Whole-Ecosystem study Shows Rapid Fish-Mercury Response to Changes in Mercury Deposition. Proceedings of the National Academy of Sciences Early Edition, PNAS 2007 104 (42) pp. 16586–16591; (published ahead of print September 27, 2007).

[138] Orihel D.M., Paterson M.J., Blanchfield P.J., Bodaly R.A., Gilmour C.C., Hintelmann H., 2007. ''Temporal Changes in the Distribution, Methylation, and Bioaccumulation of Newly Deposited Mercury in an Aquatic Ecosystem,'' *Environmental Pollution*, 154, 77–88.

[139] Scudder B.C., Chasar L.C., Wentz D.A., Bauch N.J., Brigham M.E., Moran P.W., Krabbenhoft D.P., 2009. *Mercury in fish, bed sediment, and water from streams across the United States, 1998–2005:* U.S. Geological Survey Scientific Investigations Report 2009–5109, 74 p.

[140] Grigal D.F., 2002. ''Inputs and Outputs of Mercury from Terrestrial Watersheds: A Review,'' *Environmental Review,* 10, 1–39.

[141] Yang H., Rose N.L., Battarbee R.W., Boyle J.F., 2002. ''Mercury and Lead Budgets for Lochnagar, a Scottish Mountain Lake and Its Catchment,'' *Environmental Science & Technology,* 36, 1383–1388.

[142] Krabbenhoft D.P., Engstrom D., Gilmour C., Harris R., Hurley J., Mason R., 2007. Monitoring and Evaluating Trends in Sediment and Water Indicators. In Harris R., Krabbenhoft D., Mason R., Murray M.W., Reash R., Saltman T. (Eds.), *Ecosystem Responses to Mercury Contamination: Indicators of Change.* New York: Society of Environmental Toxicology and Chemistry (SETAC) North America Workshop on Mercury Monitoring and Assessment, CRC, pp. 47–87.

[143] Lindberg S. *et al.* 2007. ''A synthesis of progress and uncertainties in attributing the sources of mercury in deposition.'' Ambio 36(1): 19–32.

[144] Orihel D.M., Paterson M.J., Blanchfield P.J., Bodaly R.A., Hintelmann H., 2008. ''Experimental Evidence of a Linear Relationship between Inorganic Mercury Loading and Methylmercury Accumulation by Aquatic Biota,'' *Environmental Science & Technology,* 41, 4952–4958.

portion of the deposition is unlikely to reach the water at all.

One commenter believes EPA incorrectly implied that its EGU risk estimates using Mercury Maps are underestimated because they do not account for legacy EGU-attributable deposition, which EPA assumes to be higher.

One commenter stated that while EPA properly screened out watersheds with significant current non-air sources of Hg, the EPA did not adequately screen out watersheds with significant Hg contributions from non-air sources, specifically watersheds with historic Hg or gold mining or other industrial Hg discharges. The same commenter stated that EPA's study was not geographically balanced and was dominated by rivers in the coastal region of the southeast that has numerous wetlands, which are favorable locations for methylation and have conditions that are not typical of much of the rest of the U.S.

Response: The EPA disagrees with the commenters who challenged the assumption of a linear proportional relationship between changes in U.S. EGU deposition and fish tissue Hg levels. The EPA specifically asked the SAB to evaluate EPA's assumption of linear proportionality in the relationship between Hg deposition and fish tissue MeHg concentrations, supported by the Mercury Maps analysis. The SAB peer review committee provided the following overall response, which generally supports EPA's approach:

> The SAB agrees with the Mercury Maps approach used in the analysis and has cited additional work that supports a linear relationship between mercury loading and accumulation in aquatic biota. These studies suggest that mercury deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. The SAB notes other modeling tools are available to link deposition to fish concentrations, but does not consider them to be superior for this analysis or recommend their use. The integration of Community Multiscale Air Quality Modeling System (CMAQ) deposition modeling to produce estimates of changes in fish tissue concentrations is considered to be sound. Although the SAB is generally satisfied with the presentation of uncertainties and limitations associated with the application of the Mercury Maps approach in qualitative terms, it recommends that the document include quantitative estimates of uncertainty available in the existing literature.[145]

The SAB peer review committee specifically addressed the MCM suggested by the commenter and had the following response:

> The SAB agrees with the application of Mercury Maps in this assessment. There are other modeling tools capable of making a national scale assessment, such as the Regional Mercury Cycling Model (R–MCM). However, the R–MCM is more data intensive and the results produced by the two model approaches should be equivalent.
>
> The R–MCM, a steady-state version of the time-dependent Dynamic Mercury Cycling Model, has been publicly available to and used by the EPA (Region 4, Athens, Environmental Research Laboratory) for a number of years. R–MCM requires more detail on water chemistry, methylation potential, etc., and yields more information as well. Substantial data support the Mercury Maps and the R–MCM steady-state results, so that the results of the sensitivity analysis and the outcomes from using the alternative models would be equivalent between the two modeling approaches. Though running an alternative model framework may provide additional reassurance that the Mercury Maps ''base case'' approach is a valid one, it is unlikely that substantial additional insight would be gained with the alternative model framework.[146]

In addition, the SAB stated, ''Since the Mercury Maps approach was developed, several recent publications have supported the finding of a linear relationship between mercury loading and accumulation in aquatic biota.[147] [148] [149] These studies suggested that mercury deposited directly to aquatic ecosystems can become quickly available to biota and accumulated in fish, and that reductions in atmospheric mercury deposition should lead to decreases in methylmercury concentrations in biota. These results substantiate EPA's assumption that proportionality between air deposition changes and fish tissue methylmercury level changes is sufficiently robust for its application in this risk assessment.'' [150]

Based on the responses of the SAB peer review committee, the EPA's use of the linear proportionality assumption, supported by the Mercury Maps analysis, is well-supported.

The EPA also disagrees with commenters' interpretation of Figure 2–17. As stated in the Hg Risk TSD, while this figure is useful to demonstrate the lack of correlation across watersheds between total deposition of Hg and MeHg concentrations in fish tissue, it is not indicative of the likely correlation between changes in Hg deposition at a given watershed and changes in MeHg concentrations in fish tissue from that watershed. The SAB agreed with this interpretation, noting the importance of Figure 2–17 demonstrating that ''spatial variability of deposition rates is only one major driver of spatial variability of fish methylmercury and that variability of ecosystem factors that control methylation potential (especially wetlands, aqueous organic carbon, pH, and sulfate) also play a key role.'' [151]

In response to recommendations from the SAB, the EPA expanded the discussion of uncertainties associated with the linearity assumption, including uncertainties related to the potential for sampled fish tissue Hg level to reflect previous Hg deposition and the potential for non-air sources of Hg to contribute to sampled fish tissue Hg levels. Each of these sources of uncertainty may result in potential bias in the estimate of exposure associated with current deposition. The EPA took steps to minimize the potential for these biases by (1) only using fish tissue Hg samples from after 1999, and (2) screening out watersheds that either contained active gold mines or had other substantial non-U.S. EGU anthropogenic emissions of Hg. The SAB commented that EPA's approach to minimizing the potential for these biases to affect the results of the risk analysis appears to be sound and that additional criteria that could be applied are unlikely to substantially change the results. As a result, the EPA disagrees with the commenter that EPA's screening process is inadequate. In addition, we conducted several sensitivity analyses to gauge the impact of excluding watersheds with the potential for non-EGU Hg emissions, and found that the results were robust to these exclusions.

In response to specific comments regarding the use of the Mercury Maps model, the EPA clarifies that the Hg Risk TSD did not directly use the Mercury Maps model. Instead, the EPA applied an assumption of linear proportionality between changes in Hg deposition and changes in MeHg concentrations in fish that is supported by the Mercury Maps modeling. By assuming steady-state conditions in apportioning fish tissue Hg levels and risk, the EPA does not attempt to project lag times. Recent research cited by the SAB [152] [153] [154] identifies relatively rapid response of fish tissue Hg to changes in Hg loading, which suggests that fish tissue Hg levels could react more

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[145] U.S. EPA–SAB, 2011.

[146] U.S. EPA–SAB, 2011.

[147] Orihel *et al.,* 2007.

[148] Orihel *et al.,* 2008.

[149] Harris *et al.,* 2007.

[150] U.S. EPA–SAB, 2011.

[151] U.S. EPA–SAB, 2011.

[152] Orihel *et al.,* 2007.

[153] Orihel *et al.,* 2008.

[154] Orihel *et al.,* 2007.

quickly to reductions in Hg deposition than previously thought. This finding reduces concern that fish tissue Hg levels could be linked to older patterns of Hg deposition and strengthens the approach used in the revised Hg Risk TSD. While fish tissue may respond rapidly to changes in Hg loading, this does not change the fact that previously emitted Hg from U.S. EGUs can be re-emitted and re-deposited, and thus affect Hg concentration in fish.

2. Characterization of Subsistence Fishing Populations and Exposure Scenario

Comment: Several commenters stated that EPA provides no clear definition of subsistence, near subsistence, or high-end fish consumption, instead assuming that poverty is a direct indication of subsistence fishing and high-end fish consumption. One commenter stated no documentation exists to supports these assumptions. Another commenter stated that EPA's definitions of subsistence fishers in the Hg Risk TSD are not consistent with earlier EPA documents and are used inconsistently throughout the Hg Risk TSD. Several commenters stated that while subsistence fishing can be associated with poverty, poverty does not indicate subsistence fishing. One commenter stated that by including watersheds with as few as 25 members of individuals living in poverty, the EPA overstates risks.

One commenter stated that it is unclear what literature the Agency says ''generally supports the plausibility of high-end subsistence-like fishing * * * to some extent across the watersheds'' and stated that if other studies exist, the EPA should provide the values for comparison.

One commenter stated that EPA combined two parameters with differing scales to establish the geographic unit used in the Hg Risk TSD risk assessment. The HUC watersheds are based on average about 35 square miles in size, while U.S. census tracts used to identify watersheds relevant for subpopulations of interest—cover a few tenths to hundreds of square miles. Several commenters stated that it is unclear how the analysis handled differences in geographic resolution between watersheds and census tracts were.

One commenter stated that the procedure for assigning census tracts could bias exposure outcomes. For example, the commenter stated that a single influential census tract in a watershed could drive risk, even if the watershed had only a minimal number of fish samples. The commenter stated that this possibility is a concern in urban areas, which account for the majority of census tracts, because these census tracts are more likely to be included in a risk analysis because they have more than 25 people living in poverty. The commenter stated that these census tracts may drive the extremes of the distribution without regard to the actual number of high-level, self-caught fish consumers within their boundaries. The commenter stated that they could not assess the potential bias and noted that EPA did not test the bias by sensitivity analyses.

Several commenters stated that EPA was not clear whether the poverty criteria were applied in all scenarios or just for the high-end female fish consumer scenario. One commenter stated that EPA should apply the minimum 25 source population criteria only to populations of women of childbearing age. One commenter stated that EPA's assumption would result in any densely populated urban census tract with a single fish tissue sample being assigned to a modeled watershed with populations potentially at-risk, regardless of the actual degree of recreational or subsistence fishing taking place there.

Response: The EPA agrees with the comments that subsistence fish consumption was not clearly defined, and we have provided a clearer definition in the revised Hg Risk TSD, however, this clarification does not result in any changes to the quantitative analysis. In the revised Hg Risk TSD, the EPA clarifies that ''subsistence fishers'' are defined as individuals who rely on noncommercial fish as a major source of protein.[155] This definition is reflected in the range of fish consumption rates used in estimating risk. The likely presence of this type of subsistence fish consumer is supported by available peer reviewed literature (*see* Table 1–5 of the revised Hg Risk TSD). These studies clearly show that a subset of surveyed fishers consumes self-caught fish at the rates cited in the Hg Risk TSD. The SAB peer review concluded that the consumption rates and locations for fishing activity are supported by the data presented in the Hg Risk TSD, and are generally reasonable and appropriate given the available data.[156]

The EPA notes that there is some confusion in the comments related to the size of the watersheds modeled. Several commenters stated that HUC watersheds are 35 km on a side. The commenters appear to be referring to HUC8 classifications. The HUCs are defined for varying spatial resolutions. The geographic unit used as the basis for generating risk estimates is HUC12, which are watersheds about 10 km on a side, which is comparable with the size of the 12 km^2 grid cells in CMAQ, which are 12 km^2. The EPA has also clarified that the specific unit of analysis for this assessment is at the watershed, not enumerated subpopulations.

The EPA only used the U.S. Census tracts to determine whether there are populations in the vicinity of a given watershed, which could increase the potential for a category of subsistence fishers to be active at that watershed. In the revised Hg Risk TSD, the EPA modified the female subsistence scenario to apply equally to all watersheds with fish tissue Hg data based on the likelihood that these populations have the potential to fish at most watersheds. As described in the revised Hg Risk TSD, the EPA made this change in response to SAB's concerns regarding the potential exclusion of watersheds with fewer than 25 individuals and regarding coverage for high-end recreational fish consumption.[157] Thus, concerns regarding the use of census data to select watersheds with the potential for subsistence fishing no longer apply to this scenario. However, for the remaining subsistence scenarios, the EPA continues to use U.S. Census tract-level data to evaluate the presence of a ''source population'' in the vicinity of the watershed being modeled for risk. In this context, the EPA uses the U.S. Census data to assess whether a socioeconomic status (SES)-differentiated group similar to the particular type of subsistence fisher being modeled (*e.g.,* poor Hispanics) are located in the vicinity of the watershed. If a source population is nearby, then this increases the potential that subsistence fishing activity could occur for that population scenario.

The EPA continues to model risk for white and black subsistence fishers active in the southeast and for Hispanics assessed nationally. In this case, the EPA links poverty with subsistence fishing, as EPA only modeled locations with poor source populations. However, in modeling these three populations, the

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[155] U.S. EPA, U.S. Environmental Protection Agency. 2000. *Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories,* Volume 3: Overview of Risk Management. Office of Science and Technology, Office of Water, U.S. Environmental Protection Agency, Washington, DC EPA 823–B–00–007.

[156] U.S. EPA–SAB, 2011.

[157] This change led to a very small increase in the number of watersheds with populations potentially at-risk. In the Hg Risk TSD accompanying the proposed rule, approximately 4 percent of modeled watersheds were excluded based on the SES-based filtering criteria.

EPA asserts that the presence of a poor source population indicates the potential for subsistence fishing activity, rather the presence of such activity. The linkage between poverty and higher rates of subsistence fish consumption is supported by the Burger *et al.* study,[158] which identified substantially higher consumption rates for poor individuals (*see* Table 5 of the study). The EPA acknowledges that subsistence fishing activity by specific subpopulations might only be present across a subset of the watersheds EPA modeled for risk. However, given the stated goal of the analysis to determine the percent of watersheds where the potential exists for exposures to U.S. EGU-attributable Hg to represent a public health hazard, identifying a set of watersheds with the potential for the type of high fish consumption that leads to high Hg exposure is appropriate. The EPA notes that relatively few watersheds (less than 4 percent) have fish tissue Hg data, and, thus, can be included in the risk assessment. Consequently, while there is the potential for including some watersheds in the analysis that may not have currently active subsistence fishing activity, it is likely that EPA excluded other watersheds from the analysis where this type of subsistence fishing activity occurs due to a lack of fish tissue Hg data.

While EPA agrees with the comment that it is likely that exposure to total MeHg through commercial fish consumption represents a more significant risk for the general population than consumption of freshwater fish obtained through self-caught fishing activity, exposure to total MeHg through self-caught fish consumption is the most significant risk for subsistence fishing populations and high-end recreational fishers. For the subset of these populations that focus their fishing activity in freshwater streams and lakes, it is also the case that they will experience a higher fraction of MeHg exposure attributable to U.S. EGU Hg emissions. As a result, the EPA focused the risk assessment on subsistence fishers active at inland freshwater watersheds because they are likely to experience the highest levels of individual risk as a result of exposure to U.S. EGU-attributable Hg.

3. Cooking Loss Adjustment Factor

Comment: Several commenters stated that EPA did not justify the selection of a cooking loss factor of 1.5 that, according to one commenter, increases estimated intake by 50 percent, thus increasing the daily MeHg intake rate by a constant factor of 33 percent and also increasing any resulting (HQ) risk estimate by a similar factor. Several commenters stated that the source of EPA's selected loss factor[159] reported a range of cooking losses from 1.1 to 6. Several commenters cite several studies that report no or highly variable changes in MeHg levels as a result of cooking fish.[160] [161] [162] [163] [164] One commenter suggested that EPA's cooking loss adjustment factor of 1.5 is at the high-end of the values supported by the literature. Another commenter stated that EPA has used other adjustment factors in previous documents, and that the adjustment factor should not be fixed across different populations given potential differences in cooking practices. Several commenters noted that the cooking loss adjustment factor should only be applied to estimates of consumption rates for prepared fish, and that some sources of consumption rates are based on raw fish.

Response: The EPA disagrees with the commenters that the selection of the cooking loss factor of 1.5 is not justified by the literature. The EPA also disagrees with the comment that the cooking loss adjustment factor of 1.5 is at the high-end of the range of values in the literature. The EPA selected the Morgan study[165] as the basis for the food preparation/cooking adjustment factor because it focused on the types of freshwater fish species representative of what might be consumed by subsistence fishing populations (*i.e.,* walleye and lake trout). This study[166] provides a range of adjustment factors for each fish type including 1.1 to 1.5 for walleye and 1.5 to 2.0 for lake trout. Given these two ranges, the EPA determined it to be reasonable to take an intermediate value between the two ranges (*i.e.,* 1.5), rather than focus on either the highest or lowest values, which is not the most conservative assumption that the EPA could have made. This study[167] also explains that preparation/cooking of fish results in an increase in MeHg levels per unit fish because Hg concentrates in the muscle, while preparation/cooking tends to reduce non-muscle elements (*e.g.,* water, bone, fat).

Regarding the alternative studies identified by the commenters, the EPA disagrees that these studies considered collectively contradict the cooking loss factor in the analysis. Specifically, the first study[168] may have included measurement of non-fish components added to dishes (*e.g.,* onions, heavy breading etc.), which could dilute the post-cooking Hg measurements and give the appearance of a cooking loss even as actual fish tissue Hg levels could have increased. In the second study,[169] the fish species are saltwater and not freshwater, and the authors note that the reduction of water and fat could increase in the Hg concentration without changing absolute content. The third study focused on measurement of *bioaccessible Hg* in raw and cooked fish.[170] However, available information currently allows us to specify the risk model in terms of total Hg intake, not bioaccessible Hg, thus, this article is potentially informative for guiding future research and methods development, not the current risk assessment. The fourth study[171] found a modest but statistically insignificant increase in Hg levels for most of the cooking methods assessed, which is directionally consistent with EPA's cooking loss adjustment. The fifth study[172] only addressed the issue qualitatively, thus cannot be used for the cooking loss factor. When considered collectively, the EPA disagrees that the additional studies identified by the commenter contradict the cooking loss factor used in the risk assessment and maintains that the Morgan study[173] remains the most

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[158] Burger, J., 2002. "Daily Consumption of Wild Fish and Game: Exposures of High End Recreationists," *International Journal of Environmental Research and Public Health,* 12 (4), 343–54.

[159] Morgan, J.N., M.R. Berry, and R.L. Graves. 1997. "Effects of Commonly Used Cooking Practices on Total Mercury Concentration in Fish and Their Impact on Exposure Assessments." *Journal of Exposure Analysis and Environmental Epidemiology* 7(1):119–133.

[160] Armbruster G., Gerow K.G., Lisk D.J., 1988. "The Effects of Six Methods of Cooking on Residues of Mercury in Striped Bass," *Nutrition Reports International,* 37, 123–126.

[161] Gutenmann, W.H. and Lisk D.J., 1991. "Higher Average Mercury Concentration in Fish Fillets after Skinning and Fat Removal," *Journal of Food Safety,* 11, 99–103.

[162] Farias L.A., Favaro, D.I., Santos J.O., Vasconcellos M.B., *et al.,* 2010. "Cooking Process Evaluation on Mercury Content in Fish," *Acta Amazonia,* 40 (4), 741–748.

[163] Perelló G., Martí-Cid R., Llobet J.M., Domingo J.L., 2008. "Effects of Various Cooking Processes on the Concentrations of Arsenic, Cadmium, Mercury, and Lead in Foods," *Journal of Agricultural and Food Chemistry,* 156 (22), 11262–11269.

[164] Torres-Escribano S., Ruiz A., Barrios L., Vélez D., Montoro R., 2011. "Influence of Mercury Bioaccessibility on Exposure Assessment Associated with Consumption of Cooked Predatory Fish in Spain," *Journal of the Science of Food and Agriculture,* 91 (6), 981–6.

[165] Morgan *et al.,* 1997.

[166] *Id.*

[167] *Id.*

[168] Farias *et al.,* 2002.

[169] Perelló *et al.,* 2008.

[170] Torres-Escribano *et al.,* 2011.

[171] Armbruster *et al.,* 1988.

[172] Gutenmann *et al.,* 1991.

[173] Morgan *et al.,* 1997.

applicable for characterizing cooking/preparation effects on Hg concentrations in fish.

The EPA agrees that application of the cooking loss adjustment factor is appropriate if the fish consumption rates are for *as cooked* or *as consumed* and not for raw fish. Careful review of the three studies used in the risk assessment to identify subsistence fisher consumption rates suggests that all three represent annual-average daily intakes (g/day) of *as consumed* or *as cooked* fish. One study stated that they used models of portion or meal size servings (the size of the serving the respondent regularly eats).[174] Therefore, the EPA interprets the fish consumption rates provided in this study [175] as representing *as cooked/prepared* and not for raw fish and for that reason, application of a preparation/cooking adjustment factor is required. Another study [176] used different sized models of cooked fish filets and therefore these consumption rates are also interpreted as represented *as cooked/prepared* and not raw fish. One study [177] [178] queried survey responders for meal portion or serving size and therefore, the consumption rates do represent *as cooked/prepared.* Because all three studies provide consumption rates based on *as cooked/prepared* or as consumed, it is appropriate to apply the cooking loss adjustment factor in modeling exposure.

4. Fish Consumption Rates and Fish Tissue Hg Characterization

Comment: One commenter stated that in the past the Agency has recommended various default consumption rates (in the general range of 130 to <150 g/day) to provide default intakes for subsistence fishers under the *Risk Assessment Guidance for Superfund (RAGS) or the Fish Advisory Guidance*.[179] [180] The commenter stated that these default consumption rates are derived from various studies and generally are based on 90th or 99th percentile distribution estimates. Another commenter stated that EPA's use of the 99th percentile fish consumption for its risk analysis is inconsistent with the Agency's risk assessment guidelines, which recommend evaluating a reasonable maximum exposure (''RME'') scenario,[181] which equates to about a 95th percentile fish consumption value. The same commenter stated that EPA applied the 99th percentile to a ''small survey of 149 South Carolina female anglers'' to calculate an ingestion rate of 373 grams per day (g/day). The commenter stated that if the 95th percentile is used the ingestion rate would be 173 g/day and if the default ingestion rate for determining ambient water standards is used the ingestion rate would be 142 g/day.

Several commenters stated that EPA based its fish consumption rates used in the risk analysis on a limited number of studies and that those studies are poorly documented.

Another commenter stated that EPA should summarize available supporting studies by basic study content, characteristics, design, size, demographics, dietary recall period, and fish intake rates by demographic variables. According to the commenter, this summary would support the scientific validity of the assessment and better illustrate the potential variability and uncertainty involved in extrapolating data from small populations to the national-scale. The commenter also noted that the three studies actually used to provide subsistence population estimates, which were extrapolated to the national-scale, included a limited number of individuals living in diverse and localized areas.

One commenter stated that the assumption with the greatest impact on risk is the fish consumption rate. That same commenter stated that using 99th percentile ingestion rate dramatically increases HQ and IQ loss compared to the 50th percentile ingestion rate. The commenter stated that when an estimate of the 95th percentile ingestion rate of the 15 to 44 year old female population is considered, the HQ is a tenth of the value computed with the 99th percentile high-end female fisher.

One commenter stated that EPA provides broad summary statistics of its fish tissue data in Table 5–2 of the Regulatory Impact Analysis (RIA), but the summary does not allow an assessment of the representativeness and robustness of the underlying data for the risk assessment, especially at the tails of the distribution. The commenter stated that the table does not include a median statistic and does not provide any information on the number of lakes and river segments in each watershed. According to the commenter, an analysis of EPA's database by the SAB indicated that 60 percent of the watersheds with fish Hg data from rivers have risks calculated based upon a sample size of one or two fish. The commenter stated that it is not reasonable to base a significant policy and regulation decision on watersheds where exposure is based on a single fish sample in a single water body within it.

Several commenters criticized EPA's use of the 75th percentile fish tissue MeHg level in a watershed. One commenter stated that EPA provided no rationale for its decision to choose the highest of the 75th percentile for fish Hg levels among rivers and lakes within the HUC. Several commenters stated that subsistence fishers are less likely to target larger fish relative to recreational fishers. Several commenters suggested that EPA include a sensitivity analysis using the mean or median fish MeHg level in a watershed. One commenter also stated that EPA arbitrarily inflated the risk estimates by assuming consumption of only fish greater than 7 inches and choosing the largest of the 75th percentile of fish Hg levels from these larger fish (*i.e.,* larger than 7 inches) for rivers and lakes. That same commenter suggested using the median of all size fish, not just those over 7 inches.

One commenter stated that EPA should quantify adverse effects from the ingestion of MeHg in seafood in addition to ingestion of MeHg from self-caught freshwater fish. According to the commenter, recent studies demonstrate that were EPA to take into account consumption of seafood, MeHg consumption in the U.S. is of even greater concern.

Response: The EPA acknowledges that the focus of the Hg Risk TSD is characterizing risk for the groups likely to experience the greatest U.S. EGU-attributable Hg risk, which are subsistence fishing populations active at inland freshwater lakes and rivers. Specifically, within that subsistence fishing population, the EPA is interested in those individuals who are most at-risk, which includes those who consume the most fish. For that reason, the EPA considered a range of high-end fish consumption rates including the 99th percentile representing the most highly-exposed individuals. In responding to the SAB peer review, the EPA clarified this focus in the

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[174] Burger *et al.,* 2002.

[175] *Id.*

[176] Shilling, Fraser, Aubrey White, Lucas Lippert, Mark Lubell (2010). Contaminated fish consumption in California's Central Valley Delta. Environmental Research 110, p. 334–344.

[177] Dellinger JA. 2004. ''Exposure assessment and initial intervention regarding fish consumption of tribal members of the Upper Great Lakes Region in the United States.'' *Environ Res* 95:325–340.

[178] Personal communication, Dr. Dellinger, September 27, 2011.

[179] U.S. EPA. 1991. *Risk Assessment Guidance for Superfund (RAGS).* Part C 1991 EPA/9285.7–01C. October.

[180] U.S. EPA. 2000. *National Guidance: Guidance for Assessing Chemical Contaminant Data for Use in Fish Advisories,* Volume 2. EPA 823–B–00–008, November.

[181] U.S. EPA. 1989. *Risk Assessment Guidance for Superfund (RAGS).* EPA/540/1–89/002. December.

introduction to the revised Hg Risk TSD and changed the full title to *revised Technical Support Document: National-Scale Assessment of Mercury Risk to Populations with High Consumption of Self-caught Freshwater Fish.*

The EPA agrees that the fish consumption rate is an important factor in calculating risk from exposure to MeHg in fish. The EPA acknowledges that the distribution of fish consumption rates is positively skewed, which means that at higher percentiles (*e.g.,* 90th, 95th, and 99th) there is a substantial increase in ingestion rates relative to the mean or median. The revised Hg Risk TSD includes a reasonableness check on the amount of fish consumed (as a daily value) reflected in the different rates. While the 99th percentile consumption rates for the subsistence female fisher (373 g/day) is substantially higher than the 90th or 95th percentile values (123 and 173 g/day respectively), the 99th percentile value translates into a 13-ounce meal. While this represents a large serving, it is still reasonable if representing an individual who receives all of their meat protein from self-caught fishing, and the 13 ounces per day do not have to be eaten all at one meal. The higher consumption rates (i.e., greater than 250 g/day) are supported by all three studies used in the risk assessment, and therefore, there is support across studies near the upper bound of likely consumption rates in this range. The EPA acknowledges uncertainty associated with estimating high-end percentile values in these studies due to relatively low sample sizes for some population groups. However, even if a few individuals reported these high self-caught fish consumption rates, making it difficult to characterize the population percentiles they represent, the values still suggest that these levels of high fish consumption exist among surveyed individuals. To determine whether a public health hazard could exist, the EPA asserts that it is reasonable to include these consumption rates as representative of the most at-risk populations. In these cases, however, the EPA acknowledges that it is important to highlight uncertainty associated with characterizing the specific population percentile that these ingestion rates represent, and EPA has done so in the revised Hg Risk TSD.

The EPA disagrees with the comment that high consumption rates are poorly documented. Evidence of these high fish consuming populations can be found in surveys [182] and specialized studies.[183] [184] [185] [186] [187] Several studies identified additional fishing populations with subsistence or near subsistence consumption rates, including urban fishing populations (including low-income populations),[188] [189] [190] Laotian communities,[191] and Hispanics. The EPA participated in 1999 in a project investigating exposures of poor, minority communities in New York City to a number of contaminants including Hg, which found these populations can have very high fish consumption rates.[192] The SAB concluded that the consumption rates and locations for fishing activity are supported by the data presented in the Hg Risk TSD, and are generally reasonable and appropriate given the available data.[193]

The EPA agrees that the Hg Risk TSD would be improved by clarifying that the literature review focused on identifying studies that characterize subsistence fish consumption for groups active at freshwater locations within the U.S., and EPA has revised the Hg Risk TSD accordingly. In the Hg Risk TSD, the EPA summarized important study attributes for the source studies used to obtain fish consumption rates. This information was provided in Table C–1 in an appendix. To improve clarity, the EPA moved the summary table to the main body in the revised Hg Risk TSD. In identifying these studies, the EPA focused on surveys for subsistence fishers that were applicable at the broader regional or national level. In the Hg Risk TSD, the EPA acknowledged the smaller sample sizes for some of the subsistence fisher groups, and in several cases the EPA did not use the 99th percentile consumption rates because the sample sizes were too low to support this level of resolution. This decision did not affect EPA's finding of a hazard to public health, which is based on the results for the female subsistence fishing population, which has an estimate of the 99th percentile consumption rate that is supported by an adequate sample size.

The EPA disagrees with the comment that it did not provide a rationale for choosing the 75th percentile fish tissue concentration across lakes and rivers in a watershed. However, the EPA modified the methodology based on evaluation of the number of samples within each watershed (responding to a recommendation from the SAB). In the revised methodology, the EPA computes the 75th percentile value at each sampling site within a watershed. The EPA then computed the average of the site-specific 75th percentile fish tissue Hg values within a given watershed. This approach does not differentiate between rivers and lakes and reflects an improved treatment of behavior, allowing for fishers to choose among multiple fishing sites within a watershed.

The EPA generally agrees with the comment that some fraction of subsistence fishers likely consume fish without consideration for size (given dietary necessity), however, the EPA considers it reasonable to assume that a subset of subsistence fishers could target larger fish in order to maximize the potential consumption per unit of fishing effort. The EPA uses this subset of subsistence fishers targeting larger fish, which is represented by the 75th percentile fish tissue value, in the risk assessment. In addition, including the female subsistence fishing population in the analysis also provides coverage for high-end recreational anglers who target larger freshwater fish. The SAB commented that: ''Using the 75th percentile of fish tissue values as a reflection of consumption of larger, but not the largest, fish among sport and subsistence fishers is a reasonable approach and is consistent with published and unpublished data on predominant types of fish consumed.'' [194] The SAB suggested that EPA include a sensitivity analysis based on use of the median value, and EPA has done so in the revised Hg Risk TSD. This sensitivity analysis showed that using the median estimates had only a small impact on the number and percent of modeled watersheds with

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[182] Burger *et al.,* 2002.

[183] Burger, J., K. Pflugh, L. Lurig, L. Von Hagen, and S. Von Hagen. 1999a. ''Fishing in Urban New Jersey: Ethnicity Affects Information Sources, Perception, and Compliance.'' *Risk Analysis* 19(2): 217–229.

[184] Burger, J., Stephens, W. L., Boring, C. S., Kuklinski, M., Gibbons, J. W., Gochfeld M. 1999b. ''Factors in Exposure Assessment: Ethnic and Socioeconomic Differences in Fishing and Soncumption of Fish Caught along the Savannah River.'' *Risk Analysis,* Vol. 19, No. 3, p. 427.

[185] California Environmental Protection Agency (CalEPA). 1997. *Chemicals in Fish Report No. 1: Consumption of Fish and Shellfish in California and the United States Final Draft Report.* Pesticide and Environmental Toxicology Section, Office of Environmental Health Hazard Assessment, July.

[186] Tai, S. 1999. ''Environmental Hazards and the Richmond Laotian American Community: A Case Study in Environmental Justice.'' Asian Law Journal 6: 189.

[187] Corburn, J. 2002. ''Combining community-based research and local knowledge to confront asthma and subsistence-fishing hazards in Greenpoint/Williamsburg, Brooklyn, New York.'' *Environmental Health Perspectives* 110(2).

[188] Burger *et al.,* 1999a.

[189] Burger *et al.,* 1999b.

[190] CalEPA, 1997.

[191] Tai, 1999.

[192] Corburn, 2002.

[193] U.S. EPA–SAB, 2011.

[194] U.S. EPA–SAB, 2011.

populations potentially at-risk from U.S. EGU-attributable MeHg exposures. In the revised Hg Risk TSD, the EPA clarified that the 7-inch cutoff represents a minimum size limit for a number of key edible freshwater fish species established at the State-level. For example, Pennsylvania establishes 7 inches as the minimum size limit for both trout and salmon (other edible fish species such as bass, walleye and northern pike have higher minimum size limits).[195]

The EPA disagrees with the comment that it is not reasonable to use watersheds where only a single fish sample is available. Although it is generally preferred to have multiple samples, the SAB noted that using a single sample is likely to underestimate the 75th percentile fish MeHg concentration and is, therefore, likely to underestimate the risk estimates for those watersheds. The SAB suggested that EPA conduct additional analyses of the fish tissue MeHg data, which EPA has done and included in the revised Hg Risk TSD. The revised Hg Risk TSD includes information on the number of watersheds modeled in the risk assessment with various fish tissue Hg samples sizes (e.g., 1, 2, 3–5, 6–10 and >10 measurements).

5. Reference Dose (RfD) for MeHg and Hg Health Effects Studies

Comment: Several commenters stated that EPA's RfD[196] is based on sound science, which was supported by the findings of the NAS Study,[197] and that EPA appropriately applied the RfD in the Hg risk assessment. The commenters also stated that recent studies find clear associations between maternal blood Hg levels and delayed child development and cardiovascular effects, as well as potential for effects due to exposure to pollutant mixtures including lead.

However, many commenters expressed concerns regarding EPA's use of the MeHg RfD as a benchmark for health risk. Several commenters raised concerns claiming that EPA has not incorporated the best available Hg toxicological data into the RfD, which results in a flawed analysis and an overestimate of the impact of Hg emissions on human health.

Several commenters stated that, when deriving the RfD, the EPA relied on the flawed Faroe Islands' children study and ignored the Seychelles Islands study,[198] which did not confirm any harm on children due to MeHg exposure. According to the commenters, application of the Faroe Island study is suspect because (1) the raw data from the study have never been made available for independent analysis and scrutiny, (2) there is potential for confounding by polychlorinated biphenyls (PCBs) and lead, (3) population exposure to MeHg was through consumption of highly contaminated pilot whale meats and blubbers, and (4) exposure levels in the U.S. remain lower than those observed in the primary study. One commenter also notes that (1) Seychelles Islanders consume far more fish than Americans do; (2) the amount of MeHg in the U.S. population is much lower than the Seychelles Islanders; and (3) all ocean fish contain about the same amount of MeHg, so MeHg intake per fish meal is similar between Americans and Seychelles Islanders. However, another commenter stated that industry arguments against using the Faroe Islands study fail to acknowledge that the study results were consistent with studies in the Seychelles Islands, New Zealand,[199] and Poland.[200]

One commenter criticized EPA for using a linear dose-response model for the RfD-based HQ metric and the IQ metric. Another commenter stated that the RfD assumes a threshold dose below which an appreciable risk of adverse effects is unlikely, and NAS did not evaluate whether MeHg exposure data were better fit by a linear or non-linear model or by a threshold or non-threshold model.

Several commenters stated that EPA's MeHg RfD is more conservative than ''safe'' levels determined by other federal agencies and claim that EPA assigned unusually high uncertainty factors. Several commenters stated that EPA's use of the 1999 National Health and Nutrition Examination Survey (NHANES) blood Hg levels show a downward trend since 1999, and the levels have been below the RfD since 2001.

One commenter stated that a study by Texas Department of State Health Services (DSHS, 2004)[201] determined that among subsistence fishers who eat fish from Caddo Lake with elevated MeHg, women of child-bearing years did not have blood Hg levels greater than the RfD. Thus, according to the commenter, the connection between MeHg in fish and adverse health effects in the U.S. is not fully understood and could involve other factors, including the protective effects of fatty acids and selenium in fish, which EPA did not taken into account.

Two commenters claim that EPA uses the RfD as if it were an absolute threshold for health risk in the risk assessment even though the RfD methodology is a screening tool for deciding when risks clearly do not exist.

Several commenters recommended adding qualitative discussions to the Hg Risk TSD regarding several aspects of uncertainty, including uncertainty in the RfD, uncertainty in extrapolating a dose-response relationship between MeHg exposure and change in IQ, uncertainty in extrapolating the dose-response relationship from marine fish and marine mammals to freshwater fish, and uncertainty due to potential confounding by PCBs in marine species.

Several commenters raised concerns regarding the relationship between MeHg exposure and IQ loss. Two commenters stated that changes in IQ are not a well-defined health consequence of MeHg exposure. One commenter stated that the SAB had reservations about EPA's use of IQ loss. Two commenters questioned whether IQ impacts would even occur because in Japan and Korea, where the maternal blood Hg levels are higher than in the U.S., there is no evidence of adverse effects. Another commenter cited a study[202] that found verbal IQ scores for children from mothers with no seafood intake were 50 percent more likely to be in the lowest quartile. One commenter questions using an IQ risk metric threshold of >1 or >2 points because variation in IQ measures and the intra-individual variation in IQ are higher than the threshold.

Several commenters question the relationship between cardiovascular effects and MeHg exposure. Two

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[195] Pennsylvania Fish and Boat Commission. 2011. *Summary Book: 2011 Pennsylvania Fishing Laws & Regulations* available at: *http://fishandboat.com/fishpub/summary/inland.html.*

[196] U.S. Environmental Protection Agency—Integrated Risk Information System (U.S. EPA–IRIS). 2001. Methylmercury (MeHg) (CASRN 22967–92–6). Available at *http://www.epa.gov/iris/subst/0073.htm.*

[197] NAS, 2000.

[198] Budtz-Jorgensen E, Debes F, Weihe P, Grandjean P. 2005. ''Adverse Mercury Effects in 7–Year-Old Children Expressed as Loss in ''IQ''.'' EPA–HQ–OAR–2002–0056–6046.

[199] Kjellstrom, T; Kennedy, P; Wallis, S; *et al.* 1986. *Physical and mental development of children with prenatal exposure to mercury from fish. Stage 1: Preliminary test at age 4.* Natl Swed Environ Protec Bd, Rpt 3080 (Solna, Sweden).

[200] Wieslaw Jedrychowski *et al.* 2006. ''Effects of Prenatal Exposure to Mercury on Cognitive and Psychomotor Function in One-Year-Old Infants: Epidemiologic Cohort Study in Poland,'' 16 Annals of Epidemiology 439.

[201] DSHS. 2005. *Health Consultation: Mercury Exposure Investigation Caddo Toxic Lake Area-Harrison County Texas.* Agency for Toxic Substances and Disease Registry. *http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/sfr/085.pdf.*

[202] Hibbeln JR, Davis JM, Steer C, Emmett P, Rogers I, Williams C, *et al.,* 2007. ''Maternal seafood consumption in pregnancy and neurodevelopmental outcomes in childhood (ALSPAC study): an observational cohort study. '' Lancet 369:

commenters cited studies examining the relationship between MeHg exposure and cardiovascular effects,[203] [204] [205] [206] [207] [208] but concluded that it seems premature to use these studies to establish a dose-response relationship.

Several commenters assert that the risks from eating seafood are low relative to the benefits, that fish advisories can limit the beneficial aspects of fish consumption, and that fish advisories are often unsuccessful in changing behavior.[209] [210] One commenter noted the important protective role of dietary selenium against MeHg toxicity because the binding affinity of Hg to Se is much higher than binding to sulfur.

Response: The EPA agrees with commenters that state the MeHg RfD is the appropriate health value for determining elevated risks from MeHg exposure and disagrees with commenters that state otherwise. At this time, the EPA is neither reviewing nor revising its 2001 RfD for MeHg. The 2001 RfD for MeHg is EPA's current peer-reviewed RfD, which is the value EPA uses in all its risk assessments. The EPA's RfD is based on multiple benchmark doses, and RfDs were calculated on various endpoints using the three extant large studies of childhood effects of in utero exposure: Faroe Islands, New Zealand, and an integrative measure including data from Seychelles. The EPA did not choose to base the MeHg RfD solely on results from the Seychelles Islands, as both the NAS [211] and an independent scientific review panel convened as part of the IRIS process [212] advised strongly against using results from a study that at the time had not shown an association between MeHg exposure and adverse effects. Further, the EPA disagrees with comments stating that EPA based the MeHg RfD solely on results from the Faroe Islands population and disagrees that the information underlying the RfD is ''poorly explained''. The EPA has provided detailed documentation for the choices underlying calculation of the RfD.[213] [214] [215] To correct a misunderstanding by the commenter, the data underlying the Faroe Islands study have been previously published in the peer reviewed literature.

The EPA disagrees that it did not incorporate the latest Hg data to support the appropriate and necessary finding. It is the policy of EPA to use the most current peer reviewed, publicly available data and methodologies in its risk assessments. However, the EPA noted in the preamble to the proposed rule that ''data published since 2001 are generally consistent with those of the earlier studies that were the basis of the RfD, demonstrating persistent effects in the Faroe Island cohort, and in some cases associations of effects with lower MeHg exposure concentrations than in the Faroe Islands. These new studies provide additional confidence that exposures above the RfD are contributing to risk of adverse effects, and that reductions in exposures above the RfD can lead to incremental reductions in risk.'' However, the EPA has not completed a comprehensive review of the new literature, and as such, it would be premature to draw conclusions about the overall implications for the RfD.

The EPA agrees that EPA's RfD is not the same as the levels used by other federal agencies. In their advice to the EPA on the appropriate bases for a MeHg RfD, NAS specifically recommended that EPA use neither the study nor the uncertainty factor employed by the Agency for Toxic Substances Disease Registry (ATSDR) in the calculation of the minimal risk level.[216]

The EPA disagrees that the uncertainty factor is ''unusually high''. The uncertainty factor used in calculation of EPA's peer-reviewed RfD is small (10 fold); half of this factor is to account for measured variability in human pharmacokinetics, which is based on advice of the NAS [217] and an independent panel of scientific peer reviewers convened as part of the IRIS process.[218]

The IRIS makes this statement regarding a threshold for MeHg, ''It is also important to note that no evidence of a threshold arose for methylmercury-related neurotoxicity within the range of exposures in the Faroe Islands study. This lack [of a threshold] is indicated by the fact that, of the K power models, K = 1 provided a better fit for the endpoint models than did higher values of K.'' [219]

The EPA disagrees that it is using the MeHg RfD as an absolute bright line for health effects in the risk assessment. As stated in the preamble to this proposed rule, the RfD is an estimate of a daily exposure to the human population that is likely to be without an appreciable risk of deleterious effects during a lifetime. The EPA also stated that no RfD defines an exposure level corresponding to zero risk. Because mercury is a cumulative neurotoxin, it is important to distinguish health effects from public health hazard. Within the context of the appropriate and necessary finding, we interpret a public health hazard as risk, rather than certain occurrence of health effects.

The EPA disagrees that exposure levels in the U.S. are lower than those in the Faroe Islands study. Exposure to MeHg in the U.S. has been reported at the same levels as those published in the Faroe Islands.[220] One study notes that in the NHANES data (1999 to 2004), the highest five percent of women's blood Hg exceeded 8.2 microgram per liter (μg/L) in the Northeast U.S. and 7.2 μg/L in coastal areas.[221] Higher levels have been reported among subjects known to consume fish. For example, one study reported mean blood Hg for adult women to be 15 μg/L; range for

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[203] Roman HA, Walsh TL, Coull BA, Dewailly É, Guallar E, Hattis D, *et al.,* 2011. Evaluation of the Cardiovascular Effects of Methylmercury Exposures: Current Evidence Supports Development of a Dose–Response Function for Regulatory Benefits Analysis. Environ Health Perspect 119:607–614.

[204] Guallar E, Sanz-Gallardo MI, van't Veer P, *et al.,* 2002. ''Mercury, fish oils, and the risk of myocardial infarction.'' N Engl J Med.;347:1747.

[205] Virtanen JK, Voutilainen S, Rissanen TH, *et al.,* 2005. ''Mercury, fish oils, and risk of acute coronary events and cardiovascular disease, coronary heart disease, and all-cause mortality in men in eastern Finland.'' Arterioscler Thromb Vasc Biol. 2005;25:228.

[206] Yoshizawa, Rimm, Morris, Spate, Hsieh, Spiegelman, Stampfer, Willett. ''Mercury and the Risk of Coronary Heart Disease in Men,'' N Engl J Med 2002; 347:1755–1760.

[207] Hallgren CG, Hallmans G, Jansson JH, *et al.,* 2001. Markers of high fish intake are associated with decreased risk of a first myocardial infarction. Br J Nutr: 86:397.

[208] Mozaffarian, Dariush. 2011. ''Mercury Exposure and Risk of Cardiovascular Disease in Two U.S. Cohorts,'' N Engl J Med 364: 1116–1125.

[209] Hibbeln *et al.,* 2007.

[210] Mozaffarian, *et al.,* 2011.

[211] NAS, 2000.

[212] U.S. EPA. 2001b. Responses to Comments of the Peer Review Panel and Public Comments on Methylmercury. Available on the Internet at *http://www.epa.gov/iris/supdocs/methpr.pdf.*

[213] U.S. EPA, 2001a. Water Quality Criterion for the Protection of the Human Health: MethylmercuryEPA–823–T–01–001, available at *http://water.epa.gov/scitech/swguidance/standards/criteria/aqlife/pollutants/methylmercury/index.cfm.*

[214] U.S. EPA–IRIS, 2001.

[215] Rice D, Schoeny R, Mahaffey K. 2003. ''Methods and Rationale for Derivation of a Reference Dose for Methylmercury by the U.S. EPA.'' Risk Analysis 23(1)107–115.

[216] NAS, 2000.

[217] Id.

[218] U.S. EPA, 2001b.

[219] U.S. EPA–IRIS, 2001.

[220] Schober Susan E, Sinks Thomas H, Jones Robert L, Bolger P Michael, McDowell Margaret, Osterloh John, Garrett E Spencer, Canady Richard A, Dillon Charles F, Sun Yu, Joseph Catherine B, Mahaffey Kathryn R. Blood mercury levels in U.S. children and women of childbearing age, 1999–2000. JAMA. 2003 Apr 2; 289(13): 1667–1674.

[221] Mahaffey, K.R., R.P. Clickner and R.A. Jeffries. 2009. Adult Women's Blood Mercury Concentrations Vary Regionally in the U.S.: Association with Patterns of Fish Consumption (NHANES 1999–2004). *Environ. Health Perspect.,* 117: 47–53.

men and women was 2 to 89.5 μg/L.[222] Note that some publications have reported Hg effects in U.S. populations at or below the current U.S. RfD.[223] [224] Also, the EPA disagrees with the commenter stating all ocean fish throughout the world contain about the same amount of MeHg. Marine fish in commerce differ widely in Hg concentration by species, and fish within the same species but caught at different locations have variable amounts of Hg in their tissues.[225] [226]

The EPA disagrees that there is a statistically discernible downward trend in the NHANES data on blood Hg. The EPA is unaware that a formal statistical analysis for temporal trends has been completed for NHANES data on blood Hg levels for the period 1999 to 2008. Mahaffey*et al.,* evaluating NHANES data collected 1999 to 2004 for women at child-bearing age, could ''not support the conclusion that there was a general downward trend in blood Hg concentrations over the 6-year study period.'' [227] However, the same publication noted that ''there was a decline in the upper percentiles reflecting the most highly exposed women'' having blood Hg concentration greater than established levels of concern. Visual observations of the data show a slight decrease in Hg blood level concentrations from 1999–2008 at the geometric mean, but this decrease may not be statistically significant. The EPA remains concerned that substantial numbers of women of childbearing age in the U.S. may have blood Hg levels that are equivalent to exposures at or above the RfD. While mean and 95th percentiles from recent NHANES data are below the blood Hg concentration equivalent to the RfD, blood levels for some portions of the population (high consumers of fish, for example) show exposures above this level. One study estimated very high blood Hg levels at the 99th percentile for females of child-bearing age.[228] Other published studies have shown that various population groups can have high blood Hg levels.[229] [230] [231] [232] [233] For example, one study found that 83 percent of the NHANES Asian population exceeded the RfD-equivalent blood mercury level.[234]

The EPA disagrees with the commenter regarding confounding by PCBs and lead. Exposure to MeHg in the Faroe Islands was largely from consumption of pilot whale meat; exposure to PCBs was found in the portion of the population who also consume whale blubber. Numerous analyses have shown neurobehavioral effects of PCBs; however, the effects of MeHg and PCB in the Faroe Islands study are separable.[235] The EPA also documented the independence of PCB and MeHg effects in the Faroe Islands population.[236] The National Institute of Environmental Health Sciences (NIEHS) concluded that both PCB and Hg had adverse effects.[237] The NAS concluded that there was no empirical evidence or theoretical mechanism to support the opinion that *in utero* Faroese exposure to PCBs exacerbated the reported MeHg effect.[238] A second set of analyses found that the effect of prenatal PCB exposure was reduced when the data were sorted into tertiles by cord PCB concentrations.[239] These analyses support a conclusion that there are measurable effects of MeHg exposure in the Faroese children that are not attributable to PCB toxicity. We also note that there was no report of lead exposure in the Faroe Islands population.

The EPA disagrees with the commenter's assertion that the connection between MeHg in fish and observed health effects is not understood due to evidence from the cited Texas study.[240] This is an exposure study rather than a study on measures of neurobehavioral or any other health endpoint. TCEQ noted that none of the Caddo Lake study participants had blood Hg levels above the benchmark dose level (BMDL) of 5.8 μg/L (one of the several used by EPA in the calculation of the MeHg RfD). The BMDL is not a ''no effect'' level. Rather it is an effect level for a percentage of the population. The EPA has noted in correspondence with TCEQ that, as an exposure study, the Caddo Lake study may be representative of the surrounding population; however, the sample size is very small. It is not appropriate to extrapolate from Caddo Lake to larger regional or national populations.

The EPA is aware of the possibility of both interactions among environmental contaminants and cumulative effects of pollutants that produce the same adverse endpoint. The EPA guidance exists for dealing with such scenarios.[241] [242] [243] [244] The Agency's concern with the likelihood of human exposure to multiple contaminants is

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[222] Hightower Jane M, Moore Dan. Mercury levels in high-end consumers of fish. Environ Health Perspect. 2003 Apr; 111(4): 604–608.

[223] Oken, E., Radesky, J.S., Wright, R.O., Bellinger, D.C., Amarasiriwardena, C.J., Kleinman, K.P., Hu, H., Gillman, M.W. 2008. Maternal fish Intake during Pregnancy, Blood Mercury Levels, and Child Cognition at Age 3 Years in a U.S. Cohort. *American Journal of Epidemiology, 167(10),* 1,171–1,181.

[224] Lederman, Sally Ann Robert L. Jones, Kathleen L. Caldwell, Virginia Rauh, Stephen E. Sheets, Deliang Tang, Sheila Viswanathan, Mark Becker, Janet L. Stein, Richard Y. Wang, and Frederica P. Perera. 2008. Relation between Cord Blood Mercury Levels and Early Child Development in a World Trade Center Cohort. *Environmental Health Perspectives* 118(8) 1085–1091.

[225] Hisamichi Y, Haraguchi K, Endo T. 2010. ''Levels of mercury and organochlorine compounds and stable isotope ratios in three tuna species taken from different regions of Japan.'' *Environ Sci Technol* 44(15): 5971–8.

[226] Sunderland EM. 2007. ''Mercury exposure from domestic and imported estuarine and marine fish in the U.S. seafood market.'' *Environ Health Perspect.* 115(2): 235–42. Epub 2006 Nov 20.

[227] Mahaffey, K.R., R.P. Clickner and R.A. Jeffries. 2009. Adult Women's Blood Mercury Concentrations Vary Regionally in the U.S.: Association with Patterns of Fish Consumption (NHANES 1999–2004). *Environ. Health Perspect.,* 117: 47–53.

[228] Tran, N.L., L. Barraj, *et al.,* 2004. ''Combining food frequency and survey data to quantify long-term dietary exposure: a methyl mercury case study.'' *Risk Anal* 24(1): 19–30.

[229] *Id.*

[230] Miranda, M.L., S. Edwards, *et al.,* 2011. ''Mercury levels in an urban pregnant population in Durham County, North Carolina.'' *Int J Environ Res Public Health* 8(3): 698–712.

[231] Hightower and Moore, 2003.

[232] Hightower, J.M., A. O'Hare, *et al.,* (2006). ''Blood mercury reporting in NHANES: identifying Asian, Pacific Islander, Native American, and multiracial groups.'' Environ Health Perspect 114(2): 173–175.

[233] McKelvey, W., R.C. Gwynn, *et al.,* 2007. ''A biomonitoring study of lead, cadmium, and mercury in the blood of New York city adults.'' Environ Health Perspect 115(10): 1435–1441.

[234] Hightower*et al.,* 2006.

[235] NAS, 2000.

[236] U.S. EPA, 2001a.

[237] National Institute of Environmental Health Sciences (NIEHS). 1998. Scientific issues relevant to assessment of health effects from exposure to methylmercury. Workshop organized by Committee on Environmental and Natural Resources (CENR) Office of Science and Technology Policy (OSTP), The White House, November 18–20, 1998, Raleigh, NC.

[238] NAS, 2000.

[239] Budtz-Jørgensen, E., N. Keiding, and P. Grandjean. 1999. Benchmark modeling of the Faroese methylmercury data. Final Report to U.S. EPA.

[240] DSHA, 2005.

[241] U.S. EPA. 1986. *Guidelines for the Health Risk Assessment of Chemical Mixtures.* U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC September. EPA/630/R–98/002. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=2256.*

[242] U.S. EPA. 1999. *Guidance for Performing Aggregate Exposure and Risk Assessments.* U.S. Environmental Protection Agency, Office of Pesticide Programs, Washington, DC October. Available at *http://www.pestlaw.com/x/guide/1999/EPA-19991029A.html.*

[243] U.S. EPA. 2000a. *Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures.* U.S. Environmental Protection Agency, Risk Assessment Forum, Washington, DC EPA/630/R–00/002. Available at *http://www.epa.gov/ncea/raf/pdfs/chem_mix/chem_mix_08_2001.pdf.*

[244] U.S. EPA. 2003a. Framework for Cumulative Risk Assessment. Risk Assessment Forum, U.S. Environmental Protection Agency. Washington, DC EPA/630/P–02/001F. EPA/600/P–02/001F. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=54944.*

reflected in the multi-chemical scope of the rulemaking. However, the EPA focused the technical analyses supporting the proposed regulation on effects of individual pollutants rather than cumulative effects.

The EPA disagrees with commenters suggesting that the RfD-based HQ is inappropriate. The SAB ''agreed that EPA's calculation of a hazard quotient for each watershed included in the assessment is appropriate as the primary means of expressing risk,'' and that ''because the RfD from which the HQ is calculated is an integrative metric of neurodevelopmental effects of methylmercury, it constitutes a reasonable basis for assessing risk.'' [245]

The SAB also recommended that EPA revise the Hg Risk TSD to include additional qualitative discussion about uncertainty in the revised Hg Risk TSD. Specifically, the SAB recommended that EPA revise the Hg Risk TSD ''to better explain the methods and choices made in the analysis, and analytical results, and where the uncertainties lie.'' The SAB noted several uncertainties related to the RfD. The EPA agrees with this recommendation and included a more complete discussion of these uncertainties in the revised Hg Risk TSD.

The EPA disagrees that the IQ metric threshold is questionable. The SAB concluded that it was reasonable to consider a loss of >1 or >2 IQ points a public health concern. The SAB stated, ''The Panel agreed that if IQ loss is retained in the risk assessment despite these reservations, a loss of one or two points would be an appropriate benchmark.'' [246] The SAB further comments in their report: ''The consensus is that if IQ were to be used, then a loss of 1 or 2 points as a population average is a credible decrement to use for this risk assessment. This metric seems to be derived from the lead literature and was peer reviewed by the Clean Air Scientific Advisory Committee (U.S. EPA CASAC 2007).[247] Although its applicability to methylmercury is questionable, the size of the decrement is justified based on the extensive analyses available from the literature reviewed by CASAC.'' [248] As noted in other studies,[249] [250] a decrease of 1–2 points at the mean results in a much larger decrease in those with IQs that are much lower or higher than the mean.

Although EPA disagrees that the IQ results are too uncertain to rely upon, the EPA acknowledges that IQ is not the most sensitive neurodevelopmental endpoint affected by MeHg exposure, as also noted by the SAB. The SAB recommended that the IQ analyses be retained but be de-emphasized in the documentation underlying the final regulation. The SAB concluded, ''The Panel does not consider it appropriate to use IQ loss in the risk assessment and recommended that this aspect of the analysis be de-emphasized, moving it to an appendix where IQ loss is discussed along with other possible endpoints not included in the primary assessment. While the Panel agreed that the concentration-response function for IQ loss used in the risk assessment is appropriate, and no better alternatives are available, IQ loss is not a sensitive response to methylmercury and its use likely underestimates the impact of reducing methylmercury in water bodies.'' [251] The EPA is following the SAB's recommendation by deemphasizing the IQ analysis and placing that analysis in an appendix to the revised Hg Risk TSD.

The SAB, however, supported the use of the IQ dose-response function calculated by EPA in the Hg Risk TSD. The SAB noted, ''The function used came from a paper by Axelrad and Bellinger (2007) that seeks to define a relationship between methylmercury exposure and IQ. A whitepaper by Bellinger (Bellinger, 2005) [252] describes the sequence of steps in relating methylmercury exposure to maternal hair mercury and then that to IQ. The Mercury Risk TSD furthers notes that IQ has shown utility in describing the health effects of other neurotoxicants. These are appropriate bases for examining a potential impact of reducing methylmercury on IQ, but the SAB does not consider these compelling reasons for using IQ as a primary driver of the risk assessment.'' [253]

The EPA disagrees that the Agency has overstated or failed to review the scientific literature on cardiovascular effects from MeHg exposure. As summarized in the preamble to the proposal, the EPA stated that the NAS study concluded that ''Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.,* neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals.'' [254] The EPA also stated that additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects, and there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. In the future, the EPA may update the MeHg RfD and will review all of the relevant scientific literature available at that time, including data on all relevant endpoints, and weight of evidence for likelihood that MeHg produces specific effects in humans.

The EPA acknowledges the research regarding the effectiveness of fish advisories. However, the proposed regulation does not address the subject of fish advisories, consumer advice on fish or efficacy of such advice. The EPA rejects the commenter's speculation regarding whether the estimated IQ impacts for the regulation are real. Adverse effects of *in utero* Hg exposure have been reported in populations in the U.S.[255] [256] In another study on neurobehavioral effects of prenatal exposure to MeHg through maternal consumption of seafood, adverse effects are observed for MeHg even without controlling for fish consumption.[257] That study suggests that at normal Japanese dietary intake of MeHg and fish nutrients, the overall effect is adverse. While Japanese fish consumption and Hg exposure are both somewhat higher than the mean U.S. exposure, these levels are still within the distribution of U.S. consumers.

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[245] U.S. EPA–SAB, 2011.

[246] U.S. EPA–SAB, 2011.

[247] U.S. Environmental Protection Agency—Science Advisory Board (U.S. EPA–SAB). 2007. *Clean Air Scientific Advisory Committee's (CASAC) Review of the 1st Draft Lead Staff Paper and Draft Lead Exposure and Risk Assessments.* EPA–CASAC–07–003. March. Available on the internet at *http://yosemite.epa.gov/sab/sabproduct.nsf/989B57DCD436111B852572AC0079DA8A/$File/casac-07-003.pdf.*

[248] U.S. EPA–SAB, 2011.

[249] Axelrad, D. A.; Bellinger, D. C.; Ryan, L. M.; Woodruff, T. J. 2007. ''Dose-response relationship of prenatal mercury exposure and IQ: An integrative analysis of epidemiologic data.'' *Environmental Health Perspectives,* 115, 609–615.

[250] Bellinger DC. 2005. *Neurobehavioral Assessments Conducted in the New Zealand, Faroe Islands, and Seychelles Islands Studies of Methylmercury Neurotoxicity in Children.* Report to the U.S. Environmental Protection Agency. EPA–HQ–OAR–2002–0056–6045.

[251] U.S. EPA–SAB, 2011.

[252] Bellinger, 2005.

[253] U.S. EPA–SAB, 2011.

[254] 76 FR 25001.

[255] Oken *et al.,* 2008.

[256] Lederman *et al.,* 2008.

[257] Suzuki, K., Nakai, K., Sugawara, T., Nakamura, T., Ohba, T., Shimada, M., Hosokawa, T., Okamura, K., Sakai, T., Kurokawa, N., Murata, K., Satoh, C., and Satoh, H. 2007. ''Neurobehavioral effects of prenatal exposure to methylmercury and PCBs, and seafood intake: neonatal behavioral assessment scale results of Tohoku study of child development.'' *Environ Res* 110, 699–704.

Moreover, many studies show that beneficial effects of fish on both cardiovascular and neurodevelopmental health are decreased by concomitant exposure to MeHg. Several studies describe one or more aspects of exposure to fish nutrients and MeHg.[258] [259] [260] [261] [262] [263] [264] Recent studies[265] [266] [267] and analyses indicate the potential for nutrients in fish (particularly marine fish) to mask some of the observed adverse effects of MeHg. Because EPA did not adjust for potential confounding by nutrients in marine fish and mammals, the benchmark doses used in the RfD derivation may be underestimated.

The EPA recognizes the potential for confounding of the effects of Hg on the developing nervous system by a range of nutrients and discusses this uncertainty in the revised Hg Risk TSD. Regarding selenium, the SAB commented that ''one SAB member suggests the use of blood markers of selenium-dependent enzyme function, noting that methylmercury irreversibly inhibits selenium-dependent enzymes that are required to support vital-but-vulnerable metabolic pathways in the brain and endocrine system. Impaired selenoenzyme activities would be observed in the blood before they would be observed in brain, but the effect is also expected to be transitory. The use of these measures is a minority view among the SAB members.''[268] The SAB did not express a consensus recommendation on adjustments to the risk estimates for exposure to selenium or other nutrients, noting that ''there is not enough known about their quantitative impact to support a recommendation of a re-analysis.''[269]

6. General Comments on Hg Risk Assessment

Comment: Several commenters generally supported the Hg risk assessment, but several other commenters generally disagreed with the Hg risk assessment. One supporter stated that EPA reasonably determined that Hg emissions pose a public health hazard, correctly requested peer review of Hg risk analysis and correctly concluded EGU-attributable MeHg poses a hazard to public health at watersheds when considering all sources of Hg deposition and U.S. EGUs alone. Two commenters noted that the contribution of U.S. EGUs to total Hg deposition can significantly contribute to hundreds of watersheds, and U.S. EGU deposition alone may endanger sensitive populations near many of these watersheds.

Several commenters claimed that overly conservative assumptions in the risk analysis render the results flawed and unreliable, including using CMAQ to model deposition, Mercury Maps, fish consumption rate and fish MeHg concentrations, overly stringent RFD, national-scale model, using poverty as a surrogate for subsistence fishing, assuming a subsistence fisher resides in most watersheds with fish tissue data, fishers only eat larger fish with high Hg concentrations, cooking loss adjustment, unrealistically high fish ingestion rates (a large fish meal every day), focused on the extremes of the distributions, cast many assumptions as an underestimate of the effect despite evidence to the contrary, and created inappropriate metrics for risk that show no improvement despite significant Hg emissions reductions in the U.S.

Several commenters cite Tetra Tech's analysis that assessed Hg risk using different consumption rates, cooking factor, mean fish tissue concentrations, and EGU-attributable Hg deposition only, which showed considerably fewer watersheds that exceed an HQ of 1 at 2016 deposition levels.

Several commenters claim that this regulation would not significantly reduce Hg exposure via fish consumption because EGU-attributable deposition is a small fraction of total deposition. One commenter stated that EPA's data shows Hg emissions from U.S. EGUs have little influence on fish Hg concentrations despite a reduction of 41 tons of Hg in the U.S. between 2005 and 2016. One commenter requested that EPA accurately describe the low health risks posed by utility hazardous air pollutant emissions. One commenter stated that EPA did not consider scientific information showing that there is no straightforward connection between Hg emissions from U.S. EGUs to the Hg level in fish, which is dependent upon many environmental factors, such as sunlight and organic matter, pH, water temperature, sulfate, bacteria, and zooplankton present in the ecosystem. One commenter stated that there is not any demonstrable evidence that anyone in the U.S. has suffered adverse health problems as a result of Hg emissions from coal-fired EGUs. One commenter stated that EPA's findings are similar to the 2000 findings where EPA found a plausible link between anthropogenic emissions of Hg from sources in the U.S. and MeHg in fish, and ''plausible'' is a euphemism for unproven.

Several commenters had recommendations for the Hg risk analysis. One commenter stated that more data from Florida should have been included because Florida is known to have a rich data set on fish Hg concentrations. One commenter stated that EPA should characterize general recreational angler fishers instead of subsistence fishers. One commenter claims that EPA made math errors in the Hg Risk TSD regarding the deposition in watersheds at specific percentiles. One commenter questioned EPA's policy metrics used to characterize Hg risk.

Several commenters stated that the Hg TSD is unclear and lacks detail, as noted by the SAB. One commenter stated that the SAB is critical of EPA's efforts, stating that the SAB found it difficult to evaluate the risk assessment based solely upon Hg Risk TSD and recommended that EPA transparently explain the methods and uncertainties. One commenter stated that because of insufficient review time and the lack of detail in the Hg Risk TSD, they could not assess key questions, such as the nation-wide representativeness of the fish tissue data.

One commenter stated the subset of watersheds considered in the analysis (*i.e.,* with fish tissue data) have clearly higher U.S. EGU-attributable deposition than the distribution of all watersheds.

One commenter stated EPA's reporting of IQ point loss is erroneous and not relevant to informing policy, and the U.S. EGU contribution to risk is marginal as evidenced by the null values for the 50th percentile watershed.

One commenter notes that U.S. EGU-attributable emissions of Hg have decreased significantly between 2005

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[258] Grandjean P, Bjereve K, Wihe P, and Sterewald u. 2001a. ''UBirthweight in a fishing community: significance of essential fatty acids and marine food contaminants.'' *In. J. Epidemiol.* 30:1272–1278.

[259] Budtz-Jorgensen, E.; Grandjean, P.; Weihe, P. 2007. ''Separation of risks and benefits of 16 seafood intake.'' *Environmental Health Perspectives.* Vol. 115, 323–327.

[260] Choi *et al.,* 2008a.

[261] Choi *et al.,* 2008b.

[262] Oken *et al.,* 2008.

[263] Strain, J.J. *et al.,* 2008. Associations of maternal long chain polyunsaturated fatty acids, methyl mercury, and infant development in the Seychelles Child Development Nutrition Study.'' *Neurotoxicology.* 29(5): 776–782.

[264] Suzuki, *et al.,* 2007.

[265] Oken *et al.,* 2008.

[266] Choi AL, Cordier S, Weihe P, Grandjean P. 2008a. ''Negative confounding in the evaluation of toxicity: the case of methylmercury in fish and seafood.'' *Crit Rev Toxicol.* 2008;38(10):877–93.

[267] Choi AL, Budtz-Jørgensen E, Jørgensen PJ, Steuerwald U, Debes F, Weihe P, Grandjean P. 2008b. ''Selenium as a potential protective factor against mercury developmental neurotoxicity.'' *Environ Res.* May;107(1):45–52. Epub 2007 Sep 12.

[268] U.S. EPA–SAB, 2011.

[269] *Id.*

and 2016, but claims that this decrease does not appear to affect the risk results.

Response: The purpose of the Hg risk assessment is not to assess the magnitude of risk reduction under the proposed rule, but rather to estimate the magnitude of absolute risk attributable to U.S. EGUs currently and following implementation of other applicable CAA requirements. That said, any potential risk reductions following implementation of the MACT rule itself would likely reflect a number of factors besides the national average U.S. EGU deposition value cited by the commenter. These additional factors include: (a) Spatial gradients in the magnitude of absolute U.S. EGU-attributable Hg deposition, (b) spatial gradients in the magnitude of reductions in Hg deposition linked to the rule, (c) availability of measured fish tissue Hg levels in the vicinity of U.S. EGUs experiencing larger Hg emission reductions to support risk modeling, and (d) the potential for subsistence fishing activity at watersheds in the vicinity of U.S. EGUs experiencing larger reductions in Hg emissions (also required to support risk modeling). It is also important to point out that while the national average U.S. EGU-attributable Hg deposition (for the 2016 scenario—see revised Hg Risk TSD) is two percent, values range up to 11 percent for the 99th percentile watershed. This illustrates the substantial spatial variation in U.S. EGU-attributable Hg deposition, which translates into spatial variation in the magnitude of U.S. EGU-attributable subsistence fisher risk.

The SAB conducted a comprehensive peer review of all of EPA's assumptions in the Hg Risk TSD, and concluded that ''the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from Hg emitted from U.S. EGUs.'' [270] Furthermore, the SAB concluded, ''The SAB regards the design of the risk assessment as suitable for its intended purpose, to inform decision-making regarding an ''appropriate and necessary finding'' for regulation of hazardous air pollutants from coal and oil-fired EGUs, provided that our recommendations are fully considered in the revision of the assessment.'' [271] Although the SAB did indicate difficulty in evaluating the risk assessment based solely on the Hg Risk TSD, the panel obtained additional information from EPA through the peer review process and determined that ''the SAB supports the overall design of and approach to the risk assessment and finds that it should provide an objective, reasonable, and credible determination of the potential for a public health hazard from mercury emitted from U.S. EGUs.'' [272] The primary advice of the SAB panel was that EPA should ''revise the Technical Support Document to better explain the methods and choices made in the analysis, and analytical results, and where the uncertainties lie.'' [273] The EPA has revised the Hg Risk TSD as part of the final rulemaking to address the SAB's recommendations and has made that revised Hg Risk TSD available in the rule docket.

The SAB concurred with EPA's analytical assumptions and overall study design for the Hg Risk TSD, including the RfD-based HQ approach, fish tissue data, 75th percentile size fish, Mercury Maps assumption, and consumption rates. Based on the SAB peer review, the EPA strongly disagrees with commenter statements that the results reported in the Hg Risk TSD are unreliable, overly conservative, extreme, inconsistent with EPA risk guidelines, or severely overstate risk based on the stated objectives of the analysis. The EPA has specifically addressed each of these assumptions in the previous sections of the preamble, and thus, does not repeat those responses here. Based on the review by the SAB, the EPA has accurately described the health risks posed by utility hazardous air pollutant emissions and disagrees with the commenter's statement that EPA has not provided any demonstrable evidence to show that adverse health risks exist. The EPA has applied peer reviewed modeling to estimate the deposition of Hg attributable to U.S. EGUs. The EPA asserts that these metrics demonstrate a clear hazard to public health from Hg emissions from U.S. EGUs.

The EPA thoroughly evaluated the Tetra Tech analysis. The EPA does not agree that the analysis by Tetra Tech uses assumptions that are ''more reasonable'', and the SAB agreed that all of EPA's assumptions in the Hg Risk TSD are reasonable and appropriate. The EPA asserts that Tetra Tech's analysis does not fully cover subsistence fishers likely to experience elevated U.S. EGU-related Hg exposure. Specifically, the risk estimate cited in the comment reflects application of a number of behavioral assumptions that provide significantly less coverage for higher risk subsistence fishers. Fish consumption surveys cited in the revised Hg Risk TSD suggest that higher percentile subsistence fishers eat more than twice the level of fish assumed by Tetra Tech. Tetra Tech's analysis also used the median fish tissue levels, but it is reasonable to assume that subsistence fishers would target somewhat larger fish to maximize the volume of edible meat per unit time spent fishing. Tetra Tech's analysis also assumed that cooking fish did not concentrate Hg, but a number of studies discussed in the revised Hg Risk TSD explicitly provide adjustment factors involving a higher unit concentration following preparation. Taken together, Tetra Tech's analysis does not address the stated goal of the risk assessment to assess the nature and magnitude of risk for those individuals likely to experience the greatest risk associated with exposure to U.S. EGU-attributable Hg.

The EPA disagrees with the commenter's assertion that this rule will not affect risks associated with Hg exposure. Hg from U.S. EGUs contributes to the levels of MeHg in fish across the country and consumption of contaminated fish can lead to increased risk of adverse health effects. The EPA has shown in the RIA (Chapter 5) that this rule will reduce Hg levels in fish.

The EPA acknowledges that U.S. EGUs contribute only a small fraction of total Hg deposition in the U.S. However, U.S. EGUs remain the largest emitter of Hg in the U.S., and the revised Hg Risk TSD shows that U.S. EGU-attributable Hg deposition results in up to 29 percent of modeled watersheds with populations potentially at-risk. Our analyses show that of the 29 percent of watersheds with population at-risk, in 10 percent of those watersheds U.S. EGU deposition alone leads to potential exposures that exceed the MeHg RfD, and in 24 percent of those watersheds, total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. Mercury risk is increasing for exposures above the RfD, and as a result, any reductions in Hg exposures in locations where total exposures exceed the RfD can result in reduced risks. While these reductions in risk may be small for most populations and locations, in some watersheds and for some populations, reductions in risk may be greater.

The SAB also directly addressed the question of the nation-wide representativeness of the fish tissue MeHg data in the national Hg risk assessment. The SAB concluded, ''Although the SAB considers the number of watersheds included in the assessment adequate, some watersheds

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[270] U.S. EPA–SAB, 2011.

[271] *Id.*

[272] *Id.*

[273] *Id.*

in areas with relatively high mercury deposition from U.S. EGUs were under-sampled due to lack of fish tissue methy[l]mercury data. The SAB encourages the Agency to contact states with these watersheds to determine if additional fish tissue methylmercury data are available to improve coverage of the assessment.'' [274] In response to the SAB's recommendations, the EPA obtained additional fish tissue sample data from several states, particularly Pennsylvania, Wisconsin, Minnesota, New Jersey, and Michigan. This additional data increased the total number of watersheds assessed in the analysis by 33 percent nationally. In Florida, the EPA assessed the Hg-related health risk for 40 watersheds. Because EPA did not find any additional fish tissue data for watersheds in Florida that could be incorporated into the analysis, the total number of watersheds in Florida assessed in the revised Hg Risk TSD remains the same as the Hg Risk TSD at proposal.

The EPA disagrees with the commenter that there were errors in the Hg Risk TSD. Instead, the commenter has misinterpreted how EPA calculated the percentiles. The percentile (and mean) values presented in Table ES–1 for total and U.S. EGU-attributable Hg deposition are not matched by watershed. In other words, the EPA queried for the percentiles (and mean) provided for total Hg deposition and presented those percentiles and then separately estimated the percentiles for U.S. EGU-attributable Hg. Therefore, the total and U.S. EGU-attributable values for the 99th percentile do not necessarily occur at the same watershed. The EPA has provided additional clarification in the revised Hg Risk TSD.

The EPA agrees with the commenter that MeHg levels in fish depend on a complicated set of environmental factors, and EPA acknowledged this in the revised Hg Risk TSD. Furthermore, the EPA acknowledges that total Hg fish tissue levels are not correlated with levels of total Hg deposition when looking across watersheds because this relationship is highly dependent on the methylation potential at the specific waterbody, which is affected by pH, sulfate deposition, turbidity, etc. However, several recent studies [275] [276] [277] show, and the SAB agrees, that it is appropriate for EPA to assume that changes in Hg deposition are linearly associated with *changes* in fish tissue concentration. In addition, the EPA agrees that the subset of watersheds in the risk analysis have somewhat higher U.S. EGU deposition than the distribution of all watersheds, but EPA disagrees that oversampling of high deposition watersheds is inappropriate.

The EPA does not agree that there is no improvement in fish Hg concentrations between 2005 and 2016, or that there will be no further improvement from decreasing Hg emissions from U.S. EGUs from the baseline in 2016. Although total risk from all Hg exposures will remain elevated in much of the U.S., much of that risk is associated with global, non-U.S. Hg emissions. U.S. EGUs remain the largest source of Hg emissions in the U.S., and reductions in those emissions will result in reduced Hg deposition in many highly impacted watersheds. As shown in the revised Hg Risk TSD, average U.S. EGU-attributable fish tissue Hg concentrations is estimated to decrease by 44 percent between 2005 and 2016. Although we did not remodel risk for the 2005 scenario in the revised Hg Risk TSD, we estimated at proposal that the total percent of modeled watersheds with populations potentially at-risk from Hg emissions from U.S. EGUs exceeding either risk metric (*i.e.*, U.S. EGUs alone or total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent) would decline from 62 percent in 2005 to 28 percent in 2016. This projected decline is primarily due to a combination of additional pollution control technologies installed to comply with federal regulations, such as CSAPR, and changing fuels, such as the shift to natural gas.

The EPA disagrees that IQ loss is erroneous or irrelevant to informing policy, but EPA has moved that analysis to an appendix in the revised Hg Risk TSD, per the SAB's recommendation. The EPA disagrees that the IQ effects at the 50th percentile watershed are useful in determining that there is not a hazard to public health because EPA's stated goal of the risk assessment was to focus on populations likely to experience relatively higher exposures to U.S. EGU-attributable Hg.

We also disagree with those commenters that point to the SAB's statements concerning the clarity of the Hg Risk TSD to suggest that the public did not have an ample opportunity to comment on the Hg risk assessment. Although it is correct that the SAB said the Hg Risk TSD was difficult to evaluate until EPA staff explained it at the public meeting in June 2011, we note that the commenters that assert that this issue amounts to a violation of CAA section 307(d) notice requirements made detailed technical comments, including many of the same comments as the SAB. Furthermore, the EPA provided notice of the peer review in the preamble to the proposed rule and a number of **Federal Register** notices advised the public of the peer review process and all the meetings were open to the public for comment and participation and the minutes of those meetings were posted on the SAB Web site. The minutes for the June 2011 meeting, during which EPA provided clarifying information, were available well within the public comment period for the proposed rule. For these reasons, we maintain that the public was provided an adequate opportunity to comment on the Hg risk assessment.

e. Non-Hg HAP Case Studies

1. Emissions for Non-Hg Case Studies

Comment: The commenters raised concerns about a wide variety of aspects of EPA's approach for emissions used for the non-Hg case studies, including the use of an arithmetic mean for computing emission factors for representing emissions of untested units, the suggestion of statistical outliers in the Cr test data, the claim that metals content of the fuel is an indicator of flawed test data, the statistical approaches used by EPA to create emission factors, the absence in EPA's approach of an equation that commenters claim better represents emissions values, that EPA's approach to estimate Cr(VI) is flawed, and the lack of coal rank as a delineating factor for emission factor calculation. The commenters also suggested that EPA should revise stack parameters used for the case studies based on better available data.

Response: In response to the comments on the emission factors, the EPA has undertaken additional analysis to address all commenter concerns. The EPA disagrees with commenter's criticisms of emission factors based on arithmetic means, and EPA demonstrates that the use of an arithmetic mean provides the most representative result. The EPA analysis has found that the geometric mean approach recommended by the commenter always under predicts actual emissions by an average of more than seventy percent. The EPA agrees with commenters' recommendations to use statistical outlier tests, but has applied tests different from those suggested by the commenters. As further explained in the response to comments document in the docket, this approach did not eliminate the Cr test data from the Cr

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[274] U.S. EPA–SAB, 2011.

[275] Orihel *et al.*, 2007.

[276] Orihel *et al.*, 2008.

[277] Harris *et al.*, 2007.

emission factors used for some of the case study emissions.

The EPA disagrees with commenters' assertions that the metal content of the coal is a basis for invalidating the test results of high Cr emissions. The identification of sources whose measured emissions do not match the commenters' preconceived idea of emissions behavior is not surprising. There are many possible explanations for these differences. For example, the inconsistency between the test data and the coal analysis could be due to any number of reasons including unrepresentative coal sampling, control device problems, degradation of the refractory, or sampling contamination. The idea that test data should be discarded because it does not match initial expectations is unfounded.

The EPA disagrees with the commenter recommendations for using an equation from AP–42, developed in part by the commenters. Based on analyses of metal emissions measured at the site compared to statistically predicted estimates, the EPA concluded that measured emissions test data better predict actual emissions, and emission factors based on the arithmetic mean are a reasonable method to estimate emissions when test data are not available. The EPA analysis of the ICR data has found that the emissions equation recommended by the commenter is not a good predictor of actual EGU emissions. The EPA also disagrees with commenters' concerns about the assumption that 12 percent of the Cr will be Cr(VI) for every coal-fired unit, which was specifically supported by the peer review on the approach for estimating cancer risks associated with Cr and Ni emissions. The EPA disagrees with the commenter's assertion that any impact of scrubbers will impact the case study analyses. In EPA's revised case study analysis, 6 facilities have risk greater than 1 in a million, and of these, four facilities have Cr as the risk driver (James River, Conesville, TVA Gallatin, and Dominion—Chesapeake Bay). For these facilities, none of the units contributing the bulk of the Cr emissions have scrubbers according to the data provided to EPA by those facilities, so scrubber impacts on Cr speciation is not relevant to EPA's conclusions based on the non-Hg case studies. In any case, the EPA disagrees with the commenter's conclusions about the impacts of scrubbers on Cr speciation and provides evidence that impacts of scrubbers on Cr speciation can have the opposite effect on Cr(VI) fractions, concluding that EPA's 12 percent assumption is somewhat conservative.

The EPA also disagrees that coal rank must be a factor in computing Cr emission factors for use in the case studies. The EPA's analysis has demonstrated that coal rank appears to play no role in non-Hg metals emissions. The EPA's newly revised emissions factor development procedures can isolate and compare subgroups based on control device type or coal rank; the ICR data were subjected to these tests and no statistical significance was found between coal rank groups.

Finally, the EPA agrees with one commenter's recommendations on revised stack parameters for the case studies and has included these revisions in the case study modeling for the final rule.

2. General Comments on Non-Hg Risk Case Study

Comment: One commenter stated that EPA's case study assessment reaffirms the need to regulate HAP emitted by both coal and oil-fired EGUs. The commenter noted that over 40 percent of the case studies conducted by EPA to quantify health hazards associated with the inhalation of non-Hg HAP indicated a cancer risk greater than or equal to the one in a million threshold level required to delist a source category under CAA section 112.

One commenter stated that EPA's case study assessment might be flawed by the use of ''beta'' tests versions of the AERMOD meteorological preprocessors (AERMINUTE and AERMET). The commenter obtained from EPA the meteorological data used for EPA's assessment of the Conesville facility and processed these data with EPA's current regulatory versions of these preprocessors, which differ from the beta version. According to the commenter, a comparison of the hourly wind speed and hourly wind direction data produced by the beta preprocessor and by current EPA preprocessors revealed numerous and often substantial disparities.

One commenter stated that EPA's finding that only three coal-fired facilities and one oil-fired facility out of roughly 440 coal-fired facilities and 97 oil-fired facilities in the U.S. indicated risk greater than one-in-a-million supports a finding that it is ''appropriate'' to regulate those four and not the other 537. Another commenter stated that EPA found only a ''few'' facilities that have estimated maximum cancer risks in excess of one in a million, and that this does not justify regulating all non-Hg HAP for all sources in this category.

One commenter stated that EPA's discussion in the preamble to the proposed rule misleads the reader into believing that non-Hg HAP emissions from EGUs are associated with serious human health effects. According to the commenter, the EPA's discussion of the effects associated with excessive exposure to an individual HAP would lead the reader to believe that those effects inevitably occur from EGU emissions because EGU emissions have trace amounts of non-Hg HAP.

One commenter stated that with the assumptions in the Utility Study, both in terms of conservative scientific estimates and overestimated amounts of oil burned by these units, the EPA concluded that the risks from oil-fired units would result in only one new cancer case every 5 years. The commenter does not believe that this level of risk warrants regulation under CAA section 112(n)(1)(A).

Several commenters stated that even if the additional studies EPA performed were accurate, they hardly demonstrate that it is necessary and appropriate to regulate coal-fired EGU HAP under CAA section 112 because three sites nationwide show risks greater than one in a million, with the highest at eight in a million.

One commenter stated that the highest cancer risk estimated for coal-fired EGUs is still within the acceptable range used by EPA in other programs and is also far less than the background exposure risks the average person experiences. The background risk of developing cancer in a lifetime is approximately one in three (0.33). According to EPA's own data, the predicted added cancer risk of exposure to HAP from U.S. EGUs would change the background risk from 0.33 to 0.330001. This level of change is so minimal that it could not be observed in any health effects study that might be conducted.

One commenter stated that EPA conducted a health risk assessment on a limited number of facilities and found a ''few'' facilities that have estimated maximum cancer risks in excess of one in a million. The commenter stated that, based on this limited health risk assessment, the EPA apparently decided that they were justified to regulate all non-Hg HAP for all sources in this category.

Several commenters stated that EPA's assumption implies that a person stays exactly at the center of a census tract for 70 years and that a unit will operate in exactly the same manner for 70 years is unrealistic. The commenters suggest that Tier 3 risk assessment is warranted or a lifetime exposure adjustment is needed.

One commenter asserts that because the alleged health benefits are derived from total exposure, the EPA should explain how its numerical emission limit units, which would not directly restrict total exposure if heat inputs increase, redress this health concern. In its preamble, the EPA simply notes that its emission limit units are consistent with, and allow for simple comparison to, other regulations.

One commenter questioned whether acid gas emissions limits for oil-fired units are ''appropriate'' or ''necessary'' because EPA's new technical analyses do not indicate a health concern from acid gas emissions from oil-fired units. According to the commenter, the EPA identifies Ni as the main HAP of concern from oil-fired units, even though cancer-related inhalation risks were well below the RfCs and EPA states that significant uncertainty remains as to whether those emissions present a health concern.

Response: The EPA agrees with the commenter that the non-Hg HAP risk assessment confirms the appropriate and necessary finding.

The EPA disagrees that EPA's case study assessment is flawed by the use of beta versions of AERMINUTE and AERMET. The EPA remodeled the case study facilities using the current versions of AERMINUTE (version 11059), AERMET (version 11059), and AERMOD (version 11103). Although there were differences in the number of calm and missing winds in the current AERMINUTE/AERMET output compared to the beta version, the resulting risks differed by less than two percent, on average. For Conesville, which had the largest difference in calms between the beta and current versions of AERMINUTE/AERMET, the risks differed by three percent. For the final rule, the case study facilities have been modeled with the current available versions of AERMINUTE, AERMET, and AERMOD.

The EPA disagrees with the commenter that having only a few case study facilities exceeding one in a million risk invalidates the ''appropriate finding''. The 16 facilities EPA selected as case studies for assessment may not represent the highest-emitting or highest-risk sources. Although case study facility selection criteria included high estimated cancer and non-cancer risks using the 2005 NEI data, high throughput, and minimal emission control, another necessary criterion was the availability of Information Collection Request (ICR) data for the EGUs at those facilities (or for similar EGUs at other facilities). Because the ICR data were collected for the purpose of developing the MACT standards, the ICR was targeted towards better performing sources for non-Hg metal HAP, acid gas HAP, and organic HAP, with a smaller set of random recipients. Therefore, facilities for which ICR data were available may not represent the highest-emitting sources. The EPA's assessment of the case study facilities for the proposed rule concluded that three coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million. For the final rule, revisions were made to the 16 case studies based on comments received, and the results indicate that 5 coal-fired facilities and 1 oil-fired facility had estimated lifetime cancer risks greater than 1 in a million. The EPA maintains that its finding that more than 30 percent of the case study facilities had a cancer risk greater than one in a million is sufficient to support the appropriate finding.

The EPA disagrees with the commenter's assertion that the health effects associated with exposures to non-Hg HAP from U.S. EGUs are mischaracterized in the preamble to the proposed rule. The discussion of the health effects of non-Hg HAP provided in the preamble includes general information on the potential health effects associated with a broad range of exposure concentrations (from low to high levels) of the various non-Hg HAP (some of which have been determined to be carcinogenic to humans) based on peer reviewed scientific information extracted from priority sources such as IRIS, Cal EPA and ATSDR health effects assessments.

The EPA disagrees with the commenter's characterization of the Utility Study. The Utility Study represented the highest-quality factual record of information available at the time regarding EGU emissions and risks. Further, the EPA's revised risk assessments of 16 case studies, performed with more recent data and refined scientific methods, indicate that there are six U.S. EGU facilities that pose estimated inhalation cancer risks greater than 1 in a million. The EPA maintains that the findings of the case studies are one element that independently supports our determination that it remains appropriate and necessary to regulate EGUs under CAA section 112.

The EPA does not agree with the commenter who suggested that EPA should interpret the results of the non-Hg HAP risk analysis in the context of background cancer risk. As explained in the preamble to the proposed rule, the EPA reasonably looked to the cancer risk threshold established under CAA section 112(c)(9)(B)(1) for delisting a source category as an indicator of the level of cancer risk that was appropriate to regulate under CAA section 112. The commenters comparison of the cancer risk from EGUs as compared with the risk of contracting cancer from unknown sources is not the standard Congress established for evaluating HAP emission risk and the commenter has provided no support for its contention that the Agency should evaluate risk in that manner. The EPA maintains that the analysis was reasonable.

The EPA does not agree with the commenter's implication that EPA must make a facility-specific finding for each HAP for each source and then only regulate individual EGU facilities for the individual HAP that identified as causing an identified hazard to public health or the environment. That approach is not required under CAA section 112(n)(1) or anywhere under CAA section 112, and it would be virtually impossible to undertake such an effort. For these reasons, the EPA does not agree with the commenter and maintains that the appropriate and necessary finding is reasonably supported by the record and consistent with the statute for all the reasons set forth in the preamble to the proposed rule and this final action.

The EPA disagrees that an exposure adjustment is needed to account for conditions changing over 70 years because it runs counter to the long-standing approach that EPA has taken to estimate the maximum individual risk, or MIR. The MIR is defined by EPA's Benzene NESHAP regulation of 1989[278] and codified by CAA section 112(f) as the lifetime risk for a person located at the site of maximum exposure 24 hours a day, 365 days a year for 70 years (*e.g.*, census block centroids). The MIR is the metric associated with the determination of whether or not a source category may be delisted from regulatory consideration under CAA section 112(c)(9). The MIR is the risk metric used to characterize the inhalation cancer risks associated with the case study facilities. The EPA used the annual average ambient air concentration of each HAP at each census block centroid as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The EPA has used this approach to estimate MIR values in all of its risk assessments to

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[278] 54 FR 38044.

support risk-based rulemakings under CAA section 112 to date.

The EPA disagrees with the commenter's assertion that the numerical emission limits being promulgated in today's final rule must be justified on their ability to redress the health concerns that were identified as the basis for regulating EGUs. The emission limits in today's rule are technology-based, as prescribed under CAA section 112, and do not need to be justified based on their ability to protect public health. Regarding potential health concerns, the EPA has up to 8 years after the promulgation of the technology-based emission limits for EGUs to determine whether the regulations protect public health with an ample margin of safety. If the regulations do not, the CAA directs EPA to promulgate additional more stringent standards (within the prescribed 8 years) to achieve the appropriate level of public health protection.

Furthermore, the EPA reasonably concluded that it was appropriate and necessary to regulate oil-fired EGUs in 2000, and EPA confirmed that conclusion was proper with the analysis set forth in the preamble to the proposed rule. Certain commenters question the determination based on their views of how the Agency can and should exercise its discretion. The EPA disagrees with these commenters and stands by the determination for the reasons set forth in the preamble to the proposed rule. The EPA also stands by the determination that the maximum cancer risks posed by emissions of oil-fired EGUs are greater than one in a million, due primarily to emissions of Ni compounds. Based on our analysis, we are unable to delist oil-fired EGUs.

3. Ni Risk

Comment: Several commenters stated that the assumptions regarding the speciation and carcinogenic potential of Ni compounds used in EPA's inhalation risk assessment of the case study facilities are overly conservative and likely to overstate the risks. With respect to Ni speciation, the commenters stated that there are substantial uncertainties regarding the species of Ni being emitted and the risk of such emissions, and that EPA has made ultraconservative assumptions aimed at overestimating the risk. The commenters stated that assigning the same carcinogenic potency of Ni subsulfide to other forms of Ni is overly conservative and inconsistent with the best available evidence.

Response: The EPA disagrees with the commenters' assertion that it is impossible to give an accurate assessment of the risks to human health from Ni emissions from EGUs, and maintains that its assessment of the potential inhalation risks from EGU emissions of Ni compounds is scientifically valid, reasonable, and based on the best-available current scientific understanding. To that end, in July 2011, the EPA completed an external peer review (using three independent expert reviewers) of the methods used to evaluate the risks from Ni and Cr compounds emitted by EGUs.[279] There were two charge questions relating to Ni in that review. First, do EPA's judgments related to speciated Ni emissions adequately take into account available speciation data, including recent industry spectrometry studies? Second, based on the speciation information available and what is known about the health effects of Ni compounds, and taking into account the existing URE values (*i.e.,* values derived by the Integrated Risk Information System,[280] California Department of Health Services,[281] and the Texas Commission on Environmental Quality [282]), which of the following approaches to derive unit risk estimates would result in a more accurate and defensible characterization of risks from exposure to Ni compounds?

1. To continue using the same approach as that developed for use in the 2000 NATA, which consists of using the IRIS URE for nickel subsulfide and assuming that nickel subsulfide constitutes 65 percent of the mass emissions of all Ni compounds.
2. To consider a more health-protective approach, based on the consistent views of the most authoritative scientific bodies (*i.e.,* NTP in their 12th ROC, IARC, and other international agencies) that consider Ni compounds to be carcinogenic as a group.
3. To make the same assumptions as in option 2, but considering alternative UREs derived by the CDHS or TCEQ.

In responding to these peer review questions, two of the reviewers agreed with the views of the most authoritative scientific bodies, which consider Ni compounds carcinogenic as a group. These reviewers, therefore, did not focus on the availability of Ni speciation profile data. The third reviewer recommended that EPA review several manuscripts on Ni speciation profiles showing that sulfidic Ni compounds (which the reviewer considered as the most potent carcinogens) are present at low levels in emissions from EGUs.

Nickel and Ni compounds have been classified as human carcinogens by national and international scientific bodies including the IARC,[283] the World Health Organization,[284] and the European Union's Scientific Committee on Health and Environmental Risks.[285] In their *12th Report of the Carcinogens,* the NTP has classified Ni compounds as known to be human carcinogens based on sufficient evidence of carcinogenicity from studies in humans showing associations between exposure to Ni compounds and cancer, and supporting animal and mechanistic data. More specifically, this classification is based on consistent findings of increased risk of cancer in exposed workers, and supporting evidence from experimental animals that shows that exposure to an assortment of Ni compounds by multiple routes causes malignant tumors at various organ sites and in multiple species. The *12th Report of the Carcinogens* states that the ''combined results of epidemiological studies, mechanistic studies, and carcinogenesis studies in rodents support the concept that Ni compounds generate Ni ions in target cells at sites critical for carcinogenesis, thus allowing consideration and evaluation of these compounds as a single group''.[286] Although the precise Ni compound (or compounds) responsible for the carcinogenic effects in humans is not always clear, studies indicate that Ni sulfate and the combinations of Ni sulfides and oxides encountered in the Ni refining industries cause cancer in humans. There have been different views on whether or not Ni compounds, as a group, should be considered as carcinogenic to humans. Some authors

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[279] U.S. EPA, 2011c.

[280] *U.S.* EPA, 1991.

[281] California Department of Health Services (CDHS) 1991. Health Risk Assessment for Nickel. Air Toxicology and Epidemiology Section, Berkeley, CA. Available online at *http://oehha.ca.gov/air/toxic_contaminants/html/Nickel.htm.*

[282] Texas Commission on Environmental Quality (TCEQ), 2011. Development Support Document for nickel and inorganic nickel compounds. Available online at *http://www.tceq.state.tx.us/assets/public/implementation/tox/dsd/final/june11/nickel_&_compounds.pdf.*

[283] International Agency for Research on Cancer (IARC), 1990. IARC monographs on the evaluation of carcinogenic risks to humans. *Chromium, nickel and welding.* Vol. 49. Lyons, France: International Agency for Research on Cancer, World Health Organization Vol. 49:256.

[284] International Labour Organization/United Nations Environment Programme, World Health Organization (WHO), 1991. Nickel. In Environmental Health Criteria No 108 Geneva.

[285] European Commission, Scientific Committee on Health and Environmental Risks (SCHER), 2006. Opinion on: Reports on Nickel, Human Health part. SCHER, 11th plenary meeting of 04 May 2006 *http://ec.europa.eu/health/ph_risk/committees/04_scher/docs/scher_o_034.pdf.*

[286] NTP, 2011.

believe that water soluble Ni, such as Ni sulfate, should not be considered a human carcinogen, based primarily on a negative Ni sulfate 2-year NTP rodent bioassay (which is different than the positive 2-year NTP bioassay for Ni subsulfide).[287] [288] [289] Although these authors agree that the epidemiological data clearly supports an association between Ni and increased cancer risk, they sustain that the data are weakest regarding water soluble Ni. A recent review [290] highlights the robustness and consistency of the epidemiological evidence across several decades showing associations between exposure to Ni and Ni compounds (including Ni sulfate) and cancer.

Based on the views of the major scientific bodies mentioned above, and those of expert peer reviewers that commented on EPA's approaches to risk characterization of Ni compounds, the EPA considers all Ni compounds to be carcinogenic as a group and does not consider Ni speciation or Ni solubility to be strong determinants of Ni carcinogenicity. With regards to non-cancer effects, comparative quantitative analysis across Ni compounds indicates that Ni sulfate is as toxic or more toxic than Ni subsulfide or Ni oxide.[291] [292]

Regarding the second charge question, two of the reviewers suggested using the URE derived by TCEQ for all Ni compounds as a group, rather than the one derived by IRIS specifically for Ni subsulfide. The third reviewer did not comment on alternative approaches. The EPA decided to continue using 100 percent of the current IRIS URE for Ni subsulfide because IRIS values are at the top of the hierarchy with respect to the dose response information used in EPA's risk characterizations, and because of the concerns about the potential carcinogenicity of all forms of Ni raised by the major national and international scientific bodies. Nevertheless, taking into account that there are potential differences in toxicity and/or carcinogenic potential across the different Ni compounds, and given that there have been two URE values derived for exposure to mixtures of Ni compounds that are 2–3 fold lower than the IRIS URE for Ni subsulfide, the EPA also considers it reasonable to use a value that is 50 percent of the IRIS URE for Ni subsulfide for providing an estimate of the lower end of a plausible range of cancer potency values for different mixtures of Ni compounds.

4. Cr Risk

Comment: One commenter stated there are several problems with EPA's analysis related to the fact that Cr emissions were evaluated as being entirely Cr(VI). The commenter stated that not all of the emitted Cr will remain in the hexavalent form by the time it reaches the target population, and that some may be converted to the much less toxic (and noncarcinogenic) trivalent species. The commenter also stated that the concentration levels considered in the case study assessment are far below occupational levels. The commenter concluded that EPA's cancer estimates should, therefore, be looked on with some skepticism. Another commenter stated that EPA's estimate of 12 percent Cr(VI) from coal-fired EGUs is unsupported, and that EPA failed to recognize that Cr(VI) is highly water-soluble and is easily reduced to Cr(III) in the presence of SO_2 in a low pH environment. The resulting Cr(III) would be expected to precipitate out in a FGD. The commenter stated that the actual amount of Cr(VI) that would be present in the emissions from an EGU with a wet scrubber is likely to be far lower than the 12 percent estimate made by EPA.

Several commenters questioned the validity of the chronic inhalation study by EPA because of (1) the use of surrogate speciated Cr emissions data instead of actual emissions data, (2) the assumption that units were run 100 percent of the time which is impossible, (3) dispersion modeling was used that is biased towards over predicting downwind impacts, and (4) estimated ambient concentrations were utilized as substitutes for real exposure concentrations for all people within a census block.

Response: The EPA disagrees with the commenters' assertion that all Cr was considered to be hexavalent. As discussed in ''Methods to Develop Inhalation Cancer Risk Estimates for Chromium and Nickel Compounds,'' [293] existing test data for utility and industrial boilers indicate that Cr(VI) is, on average, 12 percent of total Cr from coal-fired boilers. This document underwent peer review by three external reviewers, and all three reviewers considered EPA's use of the values to be reasonable given the limited data available for Cr speciation profiling. The EPRI inhalation study for coal-fired boilers also used the 12 percent value.

The EPA also disagrees that units were assumed to operate 100 percent of the time. The dispersion modeling performed for the case study facilities used hourly heat input as a temporalization factor for estimating hourly emissions, and in some cases hourly heat inputs (and emissions) were zero or very low. The commenter provided no data or information to support their claim that the dispersion modeling EPA used is biased towards overestimating downwind impacts.

The EPA disagrees with the commenters' assertion that ''real exposure concentrations for all people within a census block'' must be considered because it runs counter to the long-standing approach that EPA has taken to estimate the maximum individual risk, or MIR. The MIR is defined by EPA's Benzene NESHAP regulation of 1989 [294] and codified by CAA section 112(f) as the lifetime risk for a person located at the site of maximum exposure 24 hours a day, 365 days a year for 70 years (*e.g.,* census block centroids). The MIR is the metric associated with the determination of whether or not a source category may be delisted from regulatory consideration under CAA section 112(c)(9). The MIR is the risk metric used to characterize the inhalation cancer risks associated with the case study facilities. The EPA used the annual average ambient air concentration of each HAP at each census block centroid as a surrogate for the lifetime inhalation exposure concentration of all the people who reside in the census block. The EPA has used this approach to estimate MIR values in all of its risk assessments to support risk-based rulemakings under CAA section 112 to date.

5. Acid Gas Risk

Comment: One commenter stated that acid gas emissions from oil-fired EGUs are not of the magnitude that triggered EPA's decision to regulate EGUs in general, raising the question of whether reduction (or even total elimination) of acid gas emissions from oil-fired EGUs could have any significant effect on EPA's goals of reducing non-cancer

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[287] Oller A. Respiratory carcinogenicity assessment of soluble nickel compounds. Environ Health Perspect. 2002, 110:841–844.

[288] Heller JG, Thornhill PG, Conard BR. New views on the hypothesis of respiratory cancer risk from soluble nickel exposure; and reconsideration of this risk's historical sources in nickel refineries. J Occup Med Toxicol. 2009, 4:23.

[289] Goodman JE, Prueitt RL, Thakali S, and Oller AR. The nickel iron bioavailability model of the carcinogenic potential of nickel-containing substances in the lung. Crit Rev Toxicol. 2011, 41:142–174.

[290] Grimsrud TK and Andersen A. Evidence of carcinogenicity in humans of water-soluble nickel salts. J Occup Med Toxicol. 2010. 5:1–7. Available online at *http://www.ossup-med.com/content/5/1/7.*

[291] Haber LT, Allen BC, Kimmel CA. Non-Cancer Risk Assessment for Nickel Compounds: Issues Associated with Dose-Response Modeling of Inhalation and Oral Exposures. Toxicol Sci. 1998. 43:213–229.

[292] NTP, 1996.

[293] U.S. EPA, 2011c.

[294] 54 FR 3804.

health risk or acidification of sensitive ecosystems in the U.S.

Several commenters stated that acid gas concentrations estimated in the case study facility assessment and the Utility Study do not exceed human health thresholds of concern. Two commenters stated that HCl emissions are negligible compared to other primary emissions (such as SO_2) that can lead to potential acidification of ecosystems.

Response: We do not agree with commenter's implication that Congress intended EPA to regulate only those HAP emissions from U.S. EGUs for which an appropriate and necessary finding is made, and commenter has cited no provision of the statute that states a contrary position. The EPA concluded that we must find it ''appropriate'' to regulate EGUs under CAA section 112 if we determine that a single HAP emitted from EGUs poses a hazard to public health or the environment. If we also find that regulation is necessary, the Agency is authorized to list EGUs pursuant to CAA section 112(c) because listing is the logical first step in regulating source categories that satisfy the statutory criteria for listing under the statutory framework of CAA section 112. *See New Jersey,* 517 F.3d at 582 (stating that ''[s]ection 112(n)(1) governs how the Administrator decides whether to list EGUs * * *''). As we noted in the preamble to the proposed rule, D.C. Circuit precedent requires the Agency to regulate all HAP from major sources of HAP emissions once a source category is added to the list of categories under CAA section 112(c). *National Lime Ass'n* v. *EPA,* 233 F.3d 625, 633 (D.C. Cir. 2000). 76 FR 24989. The EPA discusses in the preamble to the proposed rule and this final action its concerns with HCl and other acid gas HAP emissions from EGUs and the Agency's approach for establishing section 112(d) standards for acid gas HAP.

6. EPRI Risk Analysis

Comment: Two commenters stated that a comprehensive tiered inhalation risk assessment (the EPRI study) using EPA-prescribed methods with improved emission factors, fuel data, and confirmed stack parameters did not identify significant health risks (cancer or non-cancer) among U.S. coal-fired power plants (as they existed in 2007). The commenters noted that these results contrast with those presented by EPA for its non-Hg case studies on 16 (15 coal-fired) power plants. The commenters stated that several issues appear to underlie these differences, indicating the need for EPA to reevaluate its assessment and to undertake more refined (Tier 3) risk assessment for any facility of concern. Several commenters stated that for non-Hg HAP EPA produced one study on chronic inhalation risk assessment that identified three sites with cancer risks greater that one in a million for Cr(VI), which was authored by EPA staff and not peer reviewed. One commenter stated that EPA study is based on misinformation and overestimates assumptions, and that EPA has no data demonstrating health impacts from EGU emissions of non-Hg HAP, or the benefit from reducing such emissions. Two commenters stated that no benefits will be derived from the non-Hg HAP emission reductions associated with the proposed rule because no non-Hg HAP health risks were proven, and that no showing was made that EGU non-Hg HAP emission levels reach levels associated with adverse health effects. Another commenter stated that EPA must complete a comparable and separate national-scale risk assessment for non-Hg metals in order to determine appropriateness of proposing emissions standards for non-Hg metals.

Response: The commenters are incorrect in the assertion that EPA's case studies were performed with less rigor than the EPRI analysis. The EPRI analysis used a tiered approach to risk assessment, beginning with Tier 1 using EPA's SCREEN3 dispersion model on all 470 coal-fired power plants in the U.S., and following with Tier 2 with EPA's Human Exposure Model (which uses the AERMOD dispersion model) for plants with higher risks from the Tier 1 modeling. Although tiered risk assessment is an appropriate approach, the Tier 2 modeling could have been more refined. For example, more meteorological data could have been used and building downwash could have been considered. The EPRI analysis ostensibly concluded that the Tier 2 modeling with HEM was conservative, and that because the modeled risks did not exceed certain thresholds, no further refinement was necessary. However, such refinements could result in higher modeled risks than those from the commenter's Tier 2 modeling.

The EPA's dispersion modeling of the case study facilities was actually performed with a greater degree of refinement than the EPRI analysis, and was consistent with EPA's *Guideline on Air Quality Models.*[295]

In contrast to the approach used in the EPRI analysis, the EPA used:

(1) 5 years of recent meteorological data from the weather station nearest to each facility, rather than one year of meteorological data. This is more representative of long-term (*i.e.,* lifetime) exposures and risks.

(2) Temporally-varying emissions based on continuous emissions monitoring data, rather than assuming a constant emission rate for each facility throughout the entire simulation.

(3) Building downwash, where appropriate.

(4) The latest version of AERMOD [version 11103].

The EPA's assessment of the case study facilities for the proposed rule concluded that three coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million. For the final rule, revisions were made to the case studies based on comments received, and the results indicate that five coal-fired facilities and one oil-fired facility had estimated lifetime cancer risks greater than one in a million.

Regarding peer review, the risk assessment methodology used by EPA for the case studies was consistent with the method that EPA uses for assessments performed for Risk and Technology Review rulemakings, which underwent peer review by the Science Advisory Board in 2009.[296] The SAB issued its peer review report in May 2010. The report generally endorsed the risk assessment methodologies used in the program. In addition, in July 2011, the EPA completed a letter peer review of the methods used to develop inhalation cancer risk estimates for Cr and Ni compounds.

f. Ecosystem Impacts From HAP

Comment: Two commenters assert that EPA is not justified in regulating acid gases based on concern about the potential that acid gases contribute to ecosystem acidification rather than concerns about hazards to public health. The commenters further claim that HCl's contribution to ecosystem acidification is de minimis. The commenters point out that EPA acknowledges uncertainty in quantification of acidification and EPA relies on recently published research[297] that is irrelevant to the question since it is based on research conducted in the peat bog ecosystem in the United Kingdom. Another commenter calls attention to several new studies published in a special issue of the

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[295] Appendix W to 40 CFR Part 51.

[296] U.S. EPA–SAB, 2010.

[297] Evans, Chris D., Don T. Monteith, David Fowler, J. Neil Cape, and Susan Brayshaw. 2011. ''Hydrochloric Acid: An Overlooked Driver of Environmental Change.'' *Environmental Science & Technology* 45 (5), 1887–1894.

journal *Ecotoxicology* devoted to the effects of MeHg on wildlife.

Response: Although EPA agrees that quantification of acidification effects has remaining uncertainty, the science and methodology has progressed in recent years. Based on recent peer reviewed research including Evans et al.,[298] acid gases can significantly contribute to acidification. The EPA published a comprehensive risk assessment of acidification effects of nitrogen and sulfur deposition[299] and a policy assessment.[300] Given the extent and importance of the sensitive ecosystems evaluated in the review of nitrogen and sulfur deposition any substance that contributes to further acidification must be considered to be affecting the public welfare. The EPA disagrees that the peer reviewed study mentioned by commenter by Evans *et al.,* (2011) is not relevant to U.S. ecosystems. The paper presents evidence that show (1) that HCl is highly mobile in the environment, transferring acidity easily through soils and water, (2) that HCl can transport longer distances than previously thought (given its presence in remote ecosystems, and (3) that it can be a larger driver of acidification than previously thought. The fact that this study took place in the U.K. is itself irrelevant. The chemical interactions of HCl in water are the same the world over and sensitive ecosystems exist in the U.S. as well as in Europe as illustrated in the ecological risk assessment[301] for NO_X and SO_X. Furthermore, the commenter is factually incorrect that EPA is justifying that it is appropriate and necessary to regulate HAP emissions from EGUs based on this one study. The EPA agrees with the commenter that Hg exposure in wildlife is responsible for various adverse health effects in many species across the U.S. and recognizes that research is ongoing in this area. As discussed in the preamble to the proposed rule, the EPA agrees that there are potential environmental risks from exposures of ecosystems through Hg and non-Hg HAP deposition. The EPA cited relevant articles from the special edition of *Ecotoxicology*[302] mentioned by the commenter in the ecosystem effects section on Chapter 5 of the RIA for this rule, which is available in the docket.

G. EPA Affirms the Finding That It Is Appropriate and Necessary to Regulate EGUs To Address Public Health and Environmental Hazards Associated With Emissions of Hg and Non-Hg HAP From EGUs

In response to peer reviews of both the Hg and non-Hg HAP risk analyses, and taking into account public comments, the EPA conducted revised analyses of the risks associated with emissions of Hg and non-Hg HAP from U.S. EGUs. These revised analyses demonstrated that the risk results reported in the preamble to the proposed rule are robust to revisions in response to the peer reviews and public comments.

Specifically, the revised Hg Risk TSD shows that up to 29 percent of modeled watersheds have populations potentially at-risk from exposure to Hg from U.S. EGUs.[303] This 29 percent of watersheds with populations potentially at-risk includes up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD, and up to 24 percent of modeled watersheds where total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. Each of these results independently supports our conclusion that U.S. EGUs pose hazards to public health.

In the preamble to the proposed rule and in the 2000 finding, the EPA explained at length the serious nature of the health effects associated with Hg exposures, and the persistent nature of Hg in the environment. Congress specifically recognized the significant impacts of persistent bioaccumulative pollutants, like Hg, when it enacted section 112(c)(6), which requires the EPA to subject source categories listed pursuant to that section to MACT standards. Congress also required certain studies be conducted under CAA section 112(n) regarding the health effects of Hg. The EPA interprets CAA section 112(n)(1), with regard to Hg, as intended to protect the public, including sensitive populations, against exposures to Hg from EGUs that would exceed the level determined by the EPA to be without appreciable risk, *e.g.,* exposures that are above the RfD for methylmercury (MeHg), or would contribute additional risk in areas where Hg exposures exceed the RfD due to contributions from all sources of Hg. Our recent technical analyses show that 98 percent of the watersheds for which we had fish tissue data have total Hg deposition such that potential exposures exceed the MeHg RfD, above which there is an increased risk of adverse effects on human health. In these watersheds, any reductions in exposures to Hg will reduce risk, and thus the incremental contribution to Hg exposure from any individual source or group of sources, such as EGUs, may reasonably be anticipated to cause additional risk.

As we have explained, in calculating the estimates described above, the EPA has used peer-reviewed methods, and focused on populations likely to be at higher risk of exposure to Hg from U.S. EGUs, *e.g.,* female subsistence fishing populations consuming at the 99th percentile fish consumption rate. The EPA did not, however, use the most conservative assumptions that would lead to upper bound risk estimates. As discussed above and in the revised Hg Risk TSD, we did not use the highest fish tissue cooking loss adjustment factor that was reported in the literature, which, had we done so, would have increased the estimates of Hg exposure substantially. Thus, we believe our analysis could understate risk to the most exposed individual, noting that we have focused on the 99th percentile consumption rate in our estimates.

Further, we were able to assess potential Hg exposures in only a small subset of generally representative watersheds in the U.S. because our analysis was necessarily premised on those water bodies for which we had fish tissue Hg samples. Specifically, we analyzed 3,141 of the approximately 88,000 watersheds in the United States. This limited set of watersheds excludes several of the watersheds with the highest U.S. EGU attributable deposition, and may also not have included watersheds with the highest sensitivity to Hg deposition, *e.g.,* the highest methylation rates (see above). Nevertheless, our analysis of the subset of watersheds we examined demonstrates that almost one third of the watersheds are estimated to have Hg deposition attributable to U.S. EGUs that contributes to potential exposures above the MeHg RfD. The SAB

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[298] Id.

[299] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Risk and Exposure Assessment for Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur (Final).* EPA–452/R–09–008a. Office of Air Quality Planning and Standards, Research Triangle Park, NC. September. Available on the Internet at *http://www.epa.gov/ttn/naaqs/standards/no2so2sec/data/NOxSOxREASep2009MainContent.pdf.*

[300] U.S. Environmental Protection Agency (U.S. EPA). 2011d. *Policy Assessment for the Review of the Secondary National Ambient Air Quality Standards for Oxides of Nitrogen and Oxides of Sulfur.* EPA–452/R–11–005a. Office of Air Quality Planning and Standards, Research Triangle Park, NC. February. Available on the Internet at *http://www.epa.gov/ttnnaaqs/standards/no2so2sec/data/20110204pamain.pdf.*

[301] U.S. EPA, 2009.

[302] *Ecotoxicology* 17:83–91, 2008.

[303] This corresponds to 28 percent of modeled watersheds with populations potentially at-risk in the analysis reported in the preamble to the proposed rule.

confirmed that the subset of watersheds we examined is sufficient.

Considering these points and the information on Hg in the record, the EPA believes that 10 percent of watersheds with populations at risk due to U.S. EGU emissions alone is unacceptable, as is 24 percent of watersheds with populations at risk due to U.S. EGU contributions in conjunction with total deposition from other sources. Taking into account the percentage of watersheds at risk, and the potential for even higher percentages to be at risk using more conservative risk assumptions and a more complete coverage of high U.S. EGU Hg deposition watersheds, the EPA concludes that Hg emissions from U.S. EGUs pose a hazard to public health.

Given these findings, and considering that (1) the revised risk analysis showed the percent of modeled watersheds with populations potentially at-risk increased from 28 to 29 percent, and (2) the revised analysis includes 36 percent more watersheds, which significantly expands the coverage in several states, we conclude that the finding that emissions of Hg from U.S. EGUs pose a hazard to public health is confirmed by the national-scale revised Hg Risk TSD. As a result, we conclude that it remains appropriate to regulate Hg emissions from U.S. EGUs because those Hg emissions pose a hazard to public health.

With regards to the revised non-Hg inhalation case studies, the highest estimated individual lifetime cancer risk for the one case study facility (out of 16) with oil-fired EGUs is estimated to be 20 in a million, driven by Ni emissions. For the facilities with coal-fired EGUs, there were five (out of 16) with maximum individual cancer risks greater than one in a million (the highest was five in a million), four of which were driven by emissions of Cr(VI), and one of which was driven by emissions of Ni. Therefore, a total of six facilities exceed the criterion for EGUs to be regulated under CAA section 112. There were also two facilities with coal-fired EGUs with maximum individual cancer risks at one in a million. In the preamble to the proposed rule, we reported that the maximum individual lifetime cancer risk for the one facility with oil-fired EGUs was estimated to be 10 in a million, and that there were 3 coal-fired EGU facilities with maximum individual cancer risks greater than 1 in a million (the highest was 8 in a million), and 1 coal-fired EGU facility with maximum individual cancer risks equal to 1 in a million. Given that (1) the lifetime cancer risk for the oil-fired EGU facility has increased from 10 to 20 in a million, (2) the number of coal-fired EGU facilities with cancer risks greater than 1 in a million has increased from 3 to 5, and (3) the highest risk coal-fired facility still has cancer risks of 5 in a million, which is above the 1 in a million benchmark, we conclude that the finding that emissions of non-Hg HAP from U.S. EGUs pose a hazard to public health is confirmed by the revised non-Hg risk inhalation case studies.

Moreover, some HAP emissions from U.S. EGUs contribute to adverse ecosystem effects. While we did not do new analyses on these topics, we reiterate that (1) Hg emissions from U.S. EGUs pose a hazard to the environment, contributing to adverse impacts on fish-eating birds and mammals, (2) Hg is a persistent bioaccumulative environmental contaminant, and as a result, failing to control Hg emissions from U.S. EGU sources will result in long-term environmental loadings of Hg, above and beyond those loadings caused by immediate deposition of Hg within the U.S.; controlling Hg emissions from U.S. EGUs helps to reduce the potential for environmental hazard from Hg now and in the future, and (4) it is appropriate to regulate those HAP which are not known to cause cancer but are known to contribute to chronic non-cancer toxicity and environmental degradation, such as the acid gases. In addition, we have identified effective controls available to reduce Hg and non-Hg HAP emissions.

In summary, we confirm the findings that Hg and non-Hg HAP emissions from U.S. EGUs each pose hazards to public health and that it remains appropriate to regulate U.S. EGUs under CAA section 112 for those reasons. We also conclude that it remains appropriate to regulate EGUs under CAA section 112 because of the magnitude of Hg and non-Hg emissions and the environmental effects of Hg and some non-Hg emissions, each of which standing alone, supports the appropriate finding. The availability of controls to reduce HAP emissions from EGUs only further supports the appropriate finding.

Our revised analyses still show that in 2016 after implementation of other provisions of the CAA, HAP emissions from U.S. EGUs are reasonably anticipated to pose hazards to public health; therefore, it is necessary to regulate EGUs under CAA section 112. Moreover, HAP emissions from U.S. EGUs are expected to continue to contribute to adverse ecosystem effects. In addition, based on evaluation of the regulations required by the CAA, including the recent CSAPR, it is necessary to regulate U.S. EGUs under CAA section 112 because the only way to ensure permanent reductions in HAP emissions from U.S. EGUs and the associated risks to public health and the environment is through standards set under CAA section 112. While CSAPR is projected to achieve some Hg reductions due to co-control of Hg provided by controls put in place to achieve required reductions in SO_2 emissions, the results of the revised Hg Risk TSD indicate that an unacceptable percentage of modeled watersheds have populations potentially at-risk from U.S. EGU-attributable Hg deposition would remain after implementation of CSAPR. While we modeled slightly higher Hg emissions from U.S. EGUs (*i.e.*, 29 tons of Hg) in our risk analysis compared to the most recent estimate of 27 tons, we do not believe this 2 ton difference would substantially change our finding that Hg emissions from U.S. EGUs pose a hazard to public health or the Hg risks reported in the preamble to the proposed rule, as this represents less than a 10 percent reduction in Hg emissions. In addition, the actual reductions in Hg that will occur due to application of controls to meet the SO_2 emissions requirements of CSAPR may differ from those projected to occur, due to differences in the technologies that individual EGU sources choose to install. The only way to ensure reductions in Hg, including those modeled as resulting from the CSAPR, is to directly regulate Hg emissions under CAA section 112.

In summary, we confirm the findings that it is necessary to regulate HAP emissions from U.S. EGUs because (1) the national-scale Hg Risk TSD shows that the hazards to public health posed by Hg emissions from U.S. EGUs will not be addressed through imposition of the CAA, (2) we cannot be certain that the identified cancer risks attributable to U.S. EGUs will be addressed through imposition of the requirements of the CAA, (3) the environmental hazards posed by acidification will not be fully addressed through imposition of the CAA, (4) regulation under CAA section 112 is the only way to ensure that all HAP emissions reductions that have been achieved since 2005 remain permanent, and (5) direct control of Hg emissions affecting U.S. deposition is only possible through regulation of U.S. emissions as we are unable to control global emissions directly. All of these findings independently support a finding that it is necessary to regulate U.S. EGUs under CAA section 112.

Based on these findings, the Agency affirms its finding that it remains appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112, and maintains that the inclusion of coal- and oil-fired EGUs on the CAA section 112(c) list of source categories regulated under CAA section 112 remains valid.

IV. Denial of Delisting Petition

During the comment period on the proposed rule, UARG submitted a petition pursuant to CAA section 112(c)(9), asking the Agency to delete a portion of the EGU source category from the list of source categories to be regulated under CAA section 112. Specifically, UARG asks that EPA delist coal-fired EGUs from the CAA section 112(c) source category list. A copy of UARG's petition has been placed in the docket for today's rulemaking, along with the analysis conducted by EPRI that UARG uses to support its petition (hereinafter referred to as UARG's analysis). In support of its petition, UARG asserts that: (1) No coal-fired EGU or group of coal-fired EGUs will emit HAP in amounts that will cause a lifetime cancer risk greater than one in one million; and (2) no coal-fired EGU or group of coal-fired EGUs will emit non-carcinogenic HAP in amounts that will exceed a level which is adequate to protect public health with an ample margin of safety or cause adverse environmental effects. We disagree with UARG's assertions and for the reasons set forth below are denying UARG's petition to delist coal-fired EGUs from the section 112(c) source category list.

A. Requirements of CAA Section 112(c)(9)

CAA section 112(c)(9)(B) provides that ''[t]he Administrator may delete any source category'' from the section 112(c) source category list if the Agency determines that: (i) For HAP that may cause cancer in humans, ''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)''; and (ii) for HAP that may result in human health effects 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.''

The EPA has the discretion to delete a source category under CAA section 112(c)(9)(B), but only if EPA concludes that the relevant requirements of CAA section 112(c)(9)(B) have been met. HAP emissions from EGUs present both cancer risks, which implicate the requirements of CAA section 112(c)(9)(B)(i), and non-cancer human health effects or adverse environmental effects, which implicate the requirements of CAA section 112(c)(9)(B)(ii). As such, UARG bears the burden of demonstrating that the requirements of *both* clauses are met.

B. Rationale for Denying UARG's Delisting Petition

The EPA is denying UARG's petition to delist EGUs from the CAA section 112(c) source category list. UARG improperly seeks to delist a portion of a CAA section 112(c) listed source category that emits carcinogens, which is contrary to the plain language of CAA section 112(c)(9). Even setting aside this fundamental defect, UARG has failed to meet the requirements of CAA section 112(c)(9)(B).

1. UARG's Attempt to Delist a Portion of a Listed Source Category Conflicts With D.C. Circuit Precedent

In December 2000, the EPA listed coal- and oil-fired EGUs as a single source category. UARG asks the Agency to delist a portion of that listed source category: Coal-fired EGUs. UARG's request conflicts, however, with D.C. Circuit precedent, which provides that for categories, like EGUs, that pose cancer risks, the EPA may not delist a portion of a source category. *NRDC* v. *U.S. EPA*, 489 F.3d 1364 (D.C. Cir. 2007). Specifically, in *NRDC*, the D.C. Circuit held that the Agency's attempt to delist a ''low-risk'' subcategory was ''contrary to the plain language of the statute,'' and that the statute only authorized the agency to remove source categories pursuant to section 112(c)(9). *Id. at 1373* (''Because EPA's interpretation of Section 112(c)(9) as allowing it to exempt the risk-based subcategory is contrary to the plain language of the statute, the EPA's interpretation fails at Chevron step one.'').

UARG's request is indistinguishable from the situation before the court in *NRDC.* UARG does not seek to delist coal- and oil-fired EGUs, which is the source category that EPA listed, but rather a portion of that category. UARG also does not dispute that coal-fired EGUs emit carcinogenic HAP. Because UARG's request to delist is contrary to the plain language of CAA section 112(c)(9)(B) and *NRDC*, we are denying the delisting petition.

2. Even Assuming, for the Sake of Argument, That EPA Could Delist a Portion of a Source Category, UARG has Failed to Meet the Requirements of CAA Section 112(c)(9)

Even assuming, for the sake of argument, that EPA could delist a portion of a source category that emits carcinogens, which it cannot, UARG has failed to demonstrate that the requirements for delisting in CAA section 112(c)(9)(i) and (ii) have been met. UARG contends that it used EPA's models and approaches, as well as the most recent data. We have carefully reviewed UARG's analyses, however, and found certain flaws that we believe bias their risk results low. Specifically, we identified flaws in emissions estimation. UARG developed estimates for all EGU facilities using data which pre-date the 2010 ICR emissions measurement data that EPA obtained to support this rule. UARG also relied upon an emissions equation developed by EPRI and DOE to develop its metal emissions estimates. With regard to that approach, the EPA analysis of the ICR data has found that the regression approach is not a good predictor of actual EGU emissions. Furthermore, we found fault with their use of the geometric mean and their outlier analysis for computing emission factors. The EPA analysis has found that the geometric mean approach underpredicts actual emissions by an average of more than seventy percent. This had an especially large impact on the arsenic, chromium, and nickel emissions estimates. These and other issues are explained in further detail in the response to comments document. As a result, we believe the resulting risk estimates in UARG's analysis are biased low. In addition, we note that there are dispersion model refinements that are not included in the UARG analyses, but were included in EPA's analysis. For example, for the dispersion modeling of the 16 non-Hg case studies, the EPA considered building downwash and used time-varying emissions, neither of which were used in UARG's analysis. These factors could also bias the UARG risk estimates low.

However, even taking UARG's analysis at face value and accepting, for arguments' sake, their assumptions and emissions estimates, UARG's own data supports denial of the petition because UARG itself identifies a maximum individual cancer risk exceeding 1 in a million, which is the statutory threshold in CAA section 112(c)(9)(B)(i). Specifically, UARG's multi-pathway model plant ingestion risk analysis concluded that adult anglers would face cancer risks of 4 in a million. For this reason alone, the petition should be denied.

UARG dismisses the 4 in a million cancer result, arguing that the refined model plant multipathway risk assessment that it conducted is ''overly conservative.'' UARG conducted its multi-pathway risk analysis to evaluate the risks associated with ingesting persistent and bioaccumulative HAP which are emitted into the atmosphere and subsequently deposit into the environment and bioaccumulate in animals which are eventually consumed as food. Instead of conducting this multipathway analysis for each EGU facility, UARG instead analyzed multi-pathway risks by evaluating a single model plant. Nothing in the record indicates, however, that UARG's model plant represents the worst-case scenario for cancer human health risks from any EGU. Indeed, although UARG claims in its petition that the site selected for its case study is ''likely as close to a worst-case scenario as is possible given the numerous variables associated with ingestion pathway risks'' (UARG petition at 12), the supporting documentation for that case study specifically acknowledges that its fictional model plant scenario ''is not intended to represent the risk due to emissions from an actual plant or the highest level of risk that could be associated with a coal-fired power plant at any location'' (EPRI at 1). The statute requires that no source in the category may cause a lifetime cancer risk greater than one in one million to the most exposed individual, and UARG has failed to make this showing. UARG has neither modeled multi-pathway risks for a worst-case model facility, nor evaluated the multipathway risks associated with each individual EGU facility. Accordingly, UARG has not made the demonstration required by CAA section 112(c)(9)(B)(i). But, even focusing on the multi-pathway risk analysis that UARG did conduct, which admittedly does not represent a worst-case facility, UARG's analysis still shows cancer risks greater than one in a million. Accordingly, UARG's petition must be denied.

Although it is not necessary to reach the requirements of CAA section 112(c)(9)(B)(ii) that address non-cancer human health risks, we note that UARG has also failed to show that ''emissions from no source in the category * * * exceed a level which is adequate to protect public health with an ample margin of safety.'' Again, even accepting, for argument's sake, the conclusions in UARG's analysis, UARG only evaluated the non-cancer *inhalation* risks associated with each EGU facility. It did not conduct a similar analysis to assess multipathway risks for each EGU facility. Instead, it conducted a model plant analysis and admits that such model plant does not represent the worst-case scenario for noncancer human health risks from any EGU. Thus, the analysis fails to fully characterize noncancer multipathway risks for the source category, and UARG's petition must be denied on this basis as well.

Finally, UARG failed to meet its burden of showing that ''no adverse environmental effect will result from emissions from any source'' pursuant to CAA section 112(c)(9)(B)(ii). UARG analyzed environmental effects only in conjunction with its model plant. Because UARG's model plant does not represent the worst-case scenario for environmental effects, UARG's analysis falls short and fails to characterize fully the potential environmental impacts, and UARG's petition must be denied.

For all of these reasons, the EPA denies UARG's petition to delist coal-fired EGUs from the CAA section 112(c) source category list.

C. EPA's Technical Analyses for the Appropriate and Necessary Finding Provide Further Support for the Conclusion That Coal-Fired EGUs Should Remain a Listed Source Category

The EPA reasonably concluded in December 2000, based on the information available to the Agency at that time, that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and added such units to the list of source categories subject to regulation under CAA section 112(d). As discussed in section III above, the EPA conducted additional, extensive technical analyses based on recent data that confirm it remains appropriate and necessary to regulate HAP from coal- and oil-fired EGUs, because such EGUs continue to pose hazards to public health. HAP emissions from coal- and oil-fired EGUs also continue to cause adverse environmental effects. UARG advances several arguments, challenging the analyses the Agency completed in support of the proposed rule. We address those arguments in section III above. The Agency's analyses supporting the appropriate and necessary finding confirm that EGUs cannot be delisted pursuant to CAA section 112(c)(9).

Specifically, as explained further in section III above, the EPA analyzed non-Hg inhalation risks from 16 EGU facility case studies, including both coal- and oil-fired EGUs, as part of its technical analyses supporting the appropriate and necessary finding. That analysis demonstrates that there are 6 EGU facilities (of the 16 that we analyzed) with cancer risks exceeding one in one million. These cancer risk levels exceed the delisting criteria set forth in CAA section 112(c)(9)(B)(i), and confirm that EGUs must remain a listed source category. As explained above, some commenters assert that EPA's analysis of non-Hg inhalation risks from EGUs conducted in support of the proposal for this rulemaking overstated emissions from, and risks associated with, EGUs. These commenters argue that the analysis supporting UARG's petition more appropriately assesses EGU risk. The EPA disagrees with these comments and addresses these comments in section III above.

Significantly, the EPA based its analysis of 16 case study EGUs directly on the 2010 emissions test data from EGUs obtained through the ICR. The EPA's 16 case study analysis used emissions data either taken directly from the 2010 emissions test data, or derived using emissions factors based on the 2010 data for similar EGU units. The EPA also included dispersion model refinements in its final case studies, as noted above. Further, the EPA re-analyzed the 16 case studies that we conducted for the proposal and revised those analyses consistent with new non-Hg HAP emissions data and corrected stack parameters provided by commenters (including UARG) during the comment period on the proposed rule. The EPA received revised information concerning emissions tests, stack heights and stack diameters for some of the case study EGU facilities. The EPA incorporated all of these corrections into our analysis and then re-analyzed the risks for the 16 case study facilities. When completed, the EPA determined that the corrections incorporated into the reanalysis had little effect on the overall results. In the final rule, the EPA concludes that the maximum individual inhalation cancer risks for 6 out of the 16 case study EGU facilities are greater than 1 in a million. These cancer risk levels confirm that EGUs do not satisfy the delisting criterion of CAA section 112(c)(9)(B)(i) and thus should remain a listed source category.

The EPA's national-scale Hg Risk TSD supporting the appropriate and necessary finding also confirm that Hg emissions from coal- and oil-fired US EGUs are reasonably anticipated to pose a hazard to public health. As discussed in section III above, the EPA interprets CAA section 112(n)(1), with regard to mercury, as intended to protect the public, including sensitive populations, against exposures to Hg from EGUs that would exceed the level determined by EPA to be without appreciable risk, e.g., exposures that are above the RfD for methylmercury (MeHg), or would contribute additional risk in areas where Hg exposures exceed the RfD due to contributions from all sources of Hg.

In order to determine whether EGU Hg emissions pose a hazard to public health, the EPA conducted a national-scale Hg Risk TSD focused on populations with high levels of self-caught freshwater fish consumption. The results of the Hg Risk TSD show that 98 percent of modeled watersheds have total exposures to MeHg that exceed the MeHg RfD, above which there is an increased risk of adverse effects on human health. In these watersheds, any reductions in exposures to Hg will reduce risk, and thus the incremental contribution to Hg exposure from any individual source or group of sources, such as EGUs, may reasonably be anticipated to cause additional risk. The Hg Risk TSD focused on those watersheds that either exceeded the RfD based on U.S. EGU attributable deposition alone, without considering other sources of deposition, or watersheds that exceed the RfD due to total Hg deposition and to which U.S. EGUs contributed at least 5 percent of the Hg deposition. The results of that analysis show that up to 29 percent of the modeled watersheds have populations that are potentially at-risk from exposure to Hg from U.S. EGUs, including up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD, and up to 24 percent of modeled watersheds where total potential exposures to MeHg exceed the RfD and U.S. EGUs contribute at least 5 percent to Hg deposition. This approach to assessing national risks from Hg deposition from EGUs was supported by the independent peer review conducted by the Science Advisory Board, as discussed fully in section III.

Finally, as discussed in section III, based on this assessment, the EPA has confirmed that Hg emitted from U.S. EGUs pose a hazard to public health and it is appropriate to regulate U.S. EGUs under CAA section 112. This determination and the confirmatory assessments support our conclusion that UARG's delisting petition must be denied.

UARG attempts to dismiss the results of EPA's national-scale Hg Risk TSD, arguing that EPA cannot consider the risks posed by EGUs in conjunction with any other risks, including those from other source categories. Nothing in CAA section 112(c)(9), however, provides that the Agency cannot consider background or emissions due to other sources. CAA section 112(c)(9)(B)(ii) provides that ''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.'' This language could be read to provide that the Agency consider only the risks associated with the source category at issue, and ignore how those risks fit with real-world exposures.[304] However, the language could also be read to provide that the Agency consider the cumulative effect of HAP emissions from the individual sources in the category in conjunction with the HAP emissions from other sources. The latter is a reasonable interpretation, especially when considering how the public is exposed to HAP emissions. Considering the individual sources in a source category in isolation treats the sources as if they exist in a vacuum, which does not mirror reality. Such an approach is particularly problematic for environmentally persistent HAP that bio-accumulate in the food chain, such as mercury.[305]

Here, the record demonstrates that 98 percent of the watersheds EPA modeled have total exposures to MeHg that exceed the MeHg RfD, above which there is increased risk of adverse effects on human health, especially on the developing nervous systems of children during gestation. EGUs remain one of the largest unregulated sources of Hg emissions, and those emissions continue to contribute to Hg exposures and risk. UARG seeks to ignore the fact that exposures above the RfD exist in almost every watershed we modeled, and instead focuses on the contribution provided solely by EGUs. The EPA did as UARG asked and found that up to 10 percent of modeled watersheds where deposition from U.S. EGUs alone leads to potential exposures that exceed the MeHg RfD. Thus, even focusing on EGU emissions in a vacuum, which we do not believe is appropriate or required under CAA section 112(c)(9), we still found that up to 10 percent of the watersheds exceed the RfD due to EGU emissions even before taking into account the numerous other sources of Hg deposition, and we believe this to be an unacceptable percentage of watersheds above the RfD. Due to the persistent, bioacccumulative nature of Hg, among other factors, we believe it is appropriate to consider the combined impact of Hg emissions from EGUs and other sources of Hg. Thus, we also considered the 24 percent of modeled watersheds where, even though U.S. EGU emissions alone are not enough to cause exposures that exceed the RfD, those emissions contribute at least 5 percent of total exposures to MeHg that exceed the RfD. The combined total of 29 percent of modeled watersheds where U.S. EGUs cause or contribute to MeHg exposures above the RfD is clearly unacceptable and thus the UARG petition to delist must be denied.

Thus, the technical analyses the Agency conducted in support of the appropriate and necessary finding confirm that EGUs should remain a listed source category.

V. Summary of This Final NESHAP

This section summarizes the requirements of the final EGU NESHAP. Section VI below summarizes the significant changes to this final rule following proposal.

A. What is the source category regulated by this final rule?

This final rule affects coal- and oil-fired EGUs.

B. What is the affected source?

An existing affected source under this final rule 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 after May 3, 2011.

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[304] The same is true with respect to section 112(c)(9)(B)(i).

[305] In a prior rulemaking, EPA stated that the language in section 112(c)(9)(B)(ii) ''does not direct EPA to extend its analysis to either emissions from other sources in other categories or subcategories or to non-attributable background concentrations.'' 71 FR 8347 (Feb. 16, 2006). The preamble to that rule repeatedly states that the ''focus'' of the delisting determination in that rule was on emissions from sources in the category under review. *See* 71 FR 8346–47. The preamble went on to compare section 112(c)(9)(B) to section 112(f)(2)(A) in a way that suggested that EPA can consider risks presented by sources other than the subject source category under section 112(f)(2), but not under section 112(c)(9). We do not believe the language of section 112(c)(9) compels any different treatment. The section 112(f) analysis occurs after a source category has already complied with section 112(d) standards, whereas, potential delistings under section 112(c)(9) may involve source categories unregulated by section 112. A delisting decision is significant in that the category that is delisted will no longer be subject to HAP regulation under the Act. It is difficult to justify why we would examine risks from other sources under section 112(f), but not under section 112(c)(9), where Congress established such a specific test for delisting.

> CAA section 112(a)(8) defines an EGU as: a 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.

If an EGU burns coal (either as a primary fuel or as a supplementary fuel) or any combination of coal with another fuel (except for solid waste as noted below) where the coal accounts for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date, the unit is considered to be coal-fired under this final rule.

If a unit is not a coal-fired unit and burns only oil or burns oil in combination with a fuel other than coal (except solid waste as noted below) where the oil accounts for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date, the unit is considered to be oil-fired under this final rule.

As noted below, the EPA is finalizing in this rule a definition to determine whether the combustion unit is ‘‘fossil fuel fired’’ such that it is considered an EGU as defined in CAA section 112(a)(8) and, thus, potentially subject to this final rule. In addition, using the construct of the definition of ‘‘oil-fired’’ from the ARP, we are finalizing in this rule a requirement that the unit fire coal or oil (or natural gas), or any combination thereof, for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year to be considered a ‘‘fossil fuel-fired’’ EGU as defined in CAA section 112(a)(8). However, if a new or existing EGU is not coal- or oil-fired, and the unit burns natural gas exclusively or burns natural gas in combination with another fuel where the natural gas constitutes 10 percent or more of the average annual heat input during any 3 calendar years or 15 percent or more of the annual heat input during any 1 calendar year, the unit is considered to be natural gas-fired EGU and not subject to this final rule. As discussed later, we believe that this definition will address those situations where an EGU co-fires limited amounts of either coal or oil with natural gas or other non-fossil fuels (e.g., biomass).

If an EGU combusts solid waste, standards issued pursuant to CAA section 129 apply to that EGU, rather than this final rule.

C. What are the pollutants regulated by this final rule?

For coal-fired EGUs, this final rule regulates HCl as a surrogate for acid gas HAP, with an alternate of SO_2 as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational; filterable PM as a surrogate for non-mercury HAP metals, with total non-mercury HAP metals and individual non-mercury HAP metals as alternative equivalent standards; Hg; and organic HAP. For oil-fired EGUs, this final rule regulates HCl and HF; filterable PM as a surrogate for total HAP metals, with individual HAP metals as alternative equivalent standards; and organic HAP.

D. What emission limits and work practice standards must I meet and what are the subcategories in the final rule?

We are finalizing the emission limitations presented in Tables 3 and 4 of this preamble. Within the two major subcategories of ‘‘coal’’ and ‘‘oil,’’ emission limitations were developed for new and existing sources for seven subcategories, two for coal-fired EGUs, one for IGCC EGUs burning synthetic gas derived from coal- and/or solid oil-derived fuel, one for solid oil-derived fuel-fired EGUs, and four for liquid oil-fired EGUs, as described in more detail below. The limited-use liquid oil-fired subcategory, discussed elsewhere in this preamble, is not presented in Table 3 because only work practice standards apply to this subcategory.

TABLE 3—EMISSION LIMITATIONS FOR COAL-FIRED AND SOLID OIL-DERIVED FUEL-FIRED EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Mercury
Existing—Unit not low rank virgin coal	3.0E–2 lb/MMBtu. (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu. (2.0E–2 lb/MWh)	1.2E0 lb/TBtu. (1.3E–2 lb/GWh).
Existing—Unit designed low rank virgin coal	3.0E–2 lb/MMBtu. (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu. (2.0E–2 lb/MWh)	1.1E+1 lb/TBtu. (1.2E–1 lb/GWh). 4.0E0 lb/TBtu [a]. (4.0E–2 lb/GWh [a]).
Existing—IGCC	4.0E–2 lb/MMBtu. (4.0E–1 lb/MWh)	5.0E–4 lb/MMBtu. (5.0E–3 lb/MWh)	2.5E0 lb/TBtu. (3.0E–2 lb/GWh).
Existing—Solid oil-derived	8.0E–3 lb/MMBtu. (9.0E–2 lb/MWh)	5.0E–3 lb/MMBtu. (8.0E–2 lb/MWh)	2.0E–1 lb/TBtu. (2.0E–3 lb/GWh).
New—Unit not low rank virgin coal	7.0E–3 lb/MWh	4.0E–4 lb/MWh	2.0E–4 lb/GWh.
New—Unit designed for low rank virgin coal	7.0E–3 lb/MWh	4.0E–4 lb/MWh	4.0E–2 lb/GWh.
New—IGCC	7.0E–2 lb/MWh [b] 9.0E–2 lb/MWh [c]	2.0E–3 lb/MWh [d]	3.0E–3 lb/GWh [e].
New—Solid oil-derived	2.0E–2 lb/MWh	4.0E–4 lb/MWh	2.0E–3 lb/GWh.

Note: lb/MMBtu = pounds pollutant per million British thermal units fuel input.
lb/TBtu = pounds pollutant per trillion British thermal units fuel input.
lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).

[a] Beyond-the-floor limit as discussed elsewhere.

[b] Duct burners on syngas; based on permit levels in comments received.

[c] Duct burners on natural gas; based on permit levels in comments received.
[d] Based on best-performing similar source.
[e] Based on permit levels in comments received.

TABLE 4—EMISSION LIMITATIONS FOR LIQUID OIL-FIRED EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Hydrogen fluoride
Existing—Liquid oil—continental	3.0E–2 lb/MMBtu (3.0E–1 lb/MWh)	2.0E–3 lb/MMBtu (1.0E–2 lb/MWh)	4.0E–4 lb/MMBtu. (4.0E–3 lb/MWh).
Existing—Liquid oil—non-continental	3.0E–2 lb/MMBtu (3.0E–1 lb/MWh)	2.0E–4 lb/MMBtu (2.0E–3 lb/MWh)	6.0E–5 lb/MMBtu. (5.0E–4 lb/MWh).
New—Liquid oil—continental	7.0E–2 lb/MWh	4.0E–4 lb/MWh	4.0E–4 lb/MWh.
New—Liquid oil—non-continental	2.0E–1 lb/MWh	2.0E–3 lb/MWh	5.0E–4 lb/MWh.

We are also finalizing alternate equivalent emission standards (for certain subcategories) to the final surrogate standards in three areas: SO_2 (for HCl), individual non-mercury metals and total non-mercury metals (for filterable PM) from coal- and solid oil-derived fuel-fired EGUs, and individual and total metals (for filterable PM) from oil-fired EGUs. The final alternate emission limitations are provided in Tables 5 and 6 of this preamble.

TABLE 5—ALTERNATE EMISSION LIMITATIONS FOR EXISTING COAL- AND OIL-FIRED EGUS

Subcategory/Pollutant	Coal-fired EGUs	IGCC	Liquid oil, continental	Liquid oil, non-continental	Solid oil-derived
SO_2	2.0E–1 lb/MMBtu (1.5E0 lb/MWh)	NA	NA	NA	3.0E–1 lb/MMBtu. (2.0E0 lb/MWh).
Total non-mercury metals	5.0E–5 lb/MMBtu (5.0E–1 lb/GWh)	6.0E–5 lb/MMBtu (5.0E–1 lb/GWh)	8.0E–4 lb/MMBtu (8.0E–3 lb/MWh) [a]	6.0E–4 lb/MMBtu (7.0E–3 lb.MWh) [a]	4.0E–5 lb/MMBtu. (6.0E–1 lb/GWh).
Antimony, Sb	8.0E–1 lb/TBtu (8.0E–3 lb/GWh)	1.4E0 lb/TBtu (2.0E–2 lb/GWh)	1.3E+1 lb/TBtu (2.0E–1 lb/GWh)	2.2E0 lb/TBtu (2.0E–2 lb/GWh)	8.0E–1 lb/TBtu. (8.0E–3 lb/GWh).
Arsenic, As	1.1E0 lb/TBtu (2.0E–2 lb/GWh)	1.5E0 lb/TBtu (2.0E–2 lb/GWh)	2.8E0 lb/TBtu (3.0E–2 lb/GWh)	4.3E0 lb/TBtu (8.0E–2 lb/GWh)	3.0E–1 lb/TBtu. (5.0E–3 lb/GWh).
Beryllium, Be	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	1.0E–1 lb/TBtu (1.0E–3 lb/GWh)	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	6.0E–1 lb/TBtu (3.0E–3 lb/GWh)	6.0E–2 lb/TBtu. (6.0E–4 lb/GWh).
Cadmium, Cd	3.0E–1 lb/TBtu (3.0E–3 lb/GWh)	1.5E–1 lb/TBtu (2.0E–3 lb/GWh)	3.0E–1 lb/TBtu 2.0E–3 lb/GWh)	3.0E–1 lb/TBtu (3.0E–3 lb/GWh)	3.0E–1 lb/TBtu. (4.0E–3 lb/GWh).
Chromium, Cr	2.8E0 lb/TBtu (3.0E–2 lb/GWh)	2.9E0 lb/TBtu (3.0E–2 lb/GWh)	5.5E0 lb/TBtu (6.0E–2 lb/GWh)	3.1E+1 lb/TBtu (3.0E–1 lb/GWh)	8.0E–1 lb/TBtu. (2.0E–2 lb/GWh).
Cobalt, Co	8.0E–1 lb/TBtu (8.0E–3 lb/GWh)	1.2E0 lb/TBtu (2.0E–2 lb/GWh)	2.1E+1 lb/TBtu (3.0E–1 lb/GWh)	1.1E+2 lb/TBtu (1.4E0 lb/GWh)	1.1E0 lb/TBtu. (2.0E–2 lb/GWh).
Lead, Pb	1.2E0 lb/TBtu (2.0E–2 lb/GWh)	1.9E+2 lb/MMBtu (1.8E0 lb/MWh)	8.1E0 lb/TBtu (8.0E–2 lb/GWh)	4.9E0 lb/TBtu (8.0E–2 lb/GWh)	8.0E–1 lb/TBtu. (2.0E–2 lb/GWh).
Manganese, Mn	4.0E0 lb/TBtu (5.0E–2 lb/GWh	2.5E0 lb/TBtu (3.0E–2 lb/GWh)	2.2E+1 lb/TBtu (3.0E–1 lb/GWh)	2.0E+1 lb/TBtu (3.0E–1 lb/GWh)	2.3E0 lb/TBtu. (4.0E–2 lb/GWh).
Mercury, Hg	NA	NA	2.0E–1 lb/TBtu (2.0E–3 lb/GWh)	4.0E–2 lb/TBtu (4.0E–4 lb/GWh).	NA.
Nickel, Ni	3.5E0 lb/TBtu (4.0E–2 lb/GWh)	6.5E0 lb/TBtu (7.0E–2 lb/GWh)	1.1E+2 lb/TBtu (1.1E0 lb/GWh)	4.7E+2 lb/TBtu (4.1E0 lb/GWh)	9.0E0 lb/TBtu. (2.0E–1 lb/GWh).
Selenium, Se	5.0E0 lb/TBtu (6.0E–2 lb/GWh)	2.2E+1 lb/TBtu (3.0E–1 lb/GWh)	3.3E0 lb/TBtu (4.0E–2 lb/GWh)	9.8E0 lb/TBtu (2.0E–1 lb/GWh)	1.2E0 lb/TBtu. (2.0E–2 lb/GWh).

NA = Not applicable.
[a] Includes Hg.

TABLE 6—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUS

Subcategory/Pollutant	Coal-fired EGUs	IGCC [a]	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
SO_2	4.0E–1 lb/MWh	4.0E–1 lb/MWh	NA	NA	4.0E–1 lb/MWh
Total non-mercury metals	6.0E–2 lb/GWh	4.0E–1 lb/GWh	2.0E–4 lb/MWh [b]	7.0E–3 lb/MWh [b]	6.0E–1 lb/GWh
Antimony, Sb	8.0E–3 lb/GWh	2.0E–2 lb/GWh	1.0E–2	8.0E–3	8.0E–3 lb/GWh
Arsenic, As	3.0E–3 lb/GWh	2.0E–2 lb/GWh	3.0E–3	6.0E–2	3.0E–3 lb/GWh
Beryllium, Be	6.0E–4 lb/GWh	1.0E–3 lb/GWh	5.0E–4	2.0E–3	6.0E–4 lb/GWh
Cadmium, Cd	4.0E–4 lb/GWh	2.0E–3 lb/GWh	2.0E–4	2.0E–3	7.0E–4 lb/GWh
Chromium, Cr	7.0E–3 lb/GWh	4.0E–2 lb/GWh	2.0E–2	2.0E–2	6.0E–3 lb/GWh
Cobalt, Co	2.0E–3 lb/GWh	4.0E–3 lb/GWh	3.0E–2	3.0E–1	2.0E–3 lb/GWh
Lead, Pb	2.0E–3 lb/GWh	9.0E–3 lb/GWh	8.0E–3	3.0E–2	2.0E–2 lb/GWh
Mercury, Hg	NA	NA	1.0E–4	4.0E–4	2.0E–3 lb/GWh
Manganese, Mn	4.0E–3 lb/GWh	2.0E–2 lb/GWh	2.0E–2	1.0E–1	7.0E–3 lb/GWh

TABLE 6—ALTERNATE EMISSION LIMITATIONS FOR NEW COAL- AND OIL-FIRED EGUS—Continued

Subcategory/Pollutant	Coal-fired EGUs	IGCC[a]	Liquid oil, continental, lb/GWh	Liquid oil, non-continental, lb/GWh	Solid oil-derived
Nickel, Ni	4.0E–2 lb/GWh	7.0E–2 lb/GWh	9.0E–2	4.1E0	4.0E–2 lb/GWh
Selenium, Se	6.0E–3 lb/GWh	3.0E–1 lb/GWh	2.0E–2	2.0E–2	6.0E–3 lb/GWh

NA = Not applicable.
[a] Based on best-performing similar source.
[b] Includes Hg.

As noted elsewhere in this preamble, we are finalizing a requirement to use filterable PM as a surrogate for the non-mercury metallic HAP and HCl as a surrogate for the acid gas HAP for all subcategories of coal-fired EGUs and for the solid oil derived fuel-fired EGUs. For all liquid oil-fired EGUs, we are finalizing a requirement to use filterable PM as a surrogate for the total metallic HAP, and we are finalizing HCl and HF limits.

In addition, we are finalizing alternative standards for certain HAP for some subcategories. The alternative pollutants and subcategories are as follows: (1) SO_2 as a surrogate to HCl for all subcategories with add-on FGD systems (except liquid oil-fired subcategories as there were no existing units from which to base an alternate SO_2 limit); (2) individual non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories); and (3) total non-mercury metallic HAP as an alternate to filterable PM for all subcategories (except that it includes Hg for liquid oil-fired subcategories). These alternative standards are discussed elsewhere in this preamble.

We are finalizing a beyond-the-floor standard for Hg only for all existing coal-fired units designed for low rank virgin coal based on the use of activated carbon injection (ACI) for Hg control, as described elsewhere in this preamble. The EPA has determined that this beyond-the-floor level is achievable after considering the relevant CAA section 112(d)(2) provisions.

As noted elsewhere in this preamble, we are also finalizing a compliance assurance option that would allow you to monitor liquid oil fuel moisture to demonstrate that fuel moisture content is no greater than 1.0 percent. Provided that demonstration is made, you will not have to conduct additional testing and monitoring to demonstrate compliance with the HCl and HF emission limits for units in both liquid oil subcategories (*i.e.,* continental and non-continental).

Pursuant to CAA section 112(h), we are finalizing a work practice standard for organic HAP, including emissions of dioxins and furans, for all subcategories of EGUs. The work practice standard being finalized requires the implementation of periodic burner tune-up procedures described elsewhere in this preamble. We are finalizing work practice standards because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, even when long duration (around 8 hour) test runs are considered. As such, we consider it impracticable to measure emissions from these units. As discussed at proposal, we believe the inaccuracy of a majority of measurements, coupled with the extended sampling times used, allow a work practice standard under CAA section 112(h) to apply to these HAP.[306] We believe that a work practice standard will lead to a better environmental outcome than would be obtained through a requirement to measure a pollutant for which results may or may not be obtained. We believe that the work practice standard will result in actions being taken that will reduce emissions of these HAP.

In addition, as discussed below, we are creating a subcategory for limited use liquid oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input and we are establishing work practice standards applicable to such units pursuant to CAA section 112(h).

We are finalizing that new or existing EGUs are ''coal-fired'' if they combust coal more than 10 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year and meet the final definition of ''fossil fuel-fired.'' We are finalizing that an EGU is considered to be in the coal-fired ''unit designed for coal greater than or equal to 8,300 Btu/lb'' subcategory if the EGU: (1) meets the final definitions of ''fossil fuel-fired'' and ''coal-fired electric utility steam generating unit;'' and (2) is not a coal-fired EGU in the ''unit designed for low rank virgin coal'' subcategory.

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 nonagglomerating 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.[307]

We are finalizing that the EGU is considered to be an IGCC unit if the EGU: (1) Combusts a synthetic gas derived from gasified coal or solid oil-derived fuel (*e.g.,* petroleum coke, pet coke), (2) meets the final definition of ''fossil fuel-fired,'' and (3) is classified as an IGCC unit. We are not subcategorizing IGCC EGUs based on the source of the syngas used (e.g., coal, petroleum coke). Based on information available to the Agency, although the fuel characteristics of coal and petcoke are quite different, the syngas products from both feedstocks have similar HAP content and similar HAP emissions characteristics that can be controlled in a similar manner.[308]

We are finalizing that the EGU is considered to be in the ''Continental liquid oil-fired'' subcategory if (1) meets the final definitions of ''oil-fired electric utility steam generating unit'' and ''fossil fuel-fired;'' and (2) is located in the continental United States (U.S.).

We are finalizing that the EGU is considered to be ''Non-continental liquid oil-fired'' subcategory if (1) meets the final definitions of ''oil-fired electric utility steam generating unit'' and

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[306] We would also note that the EPA, as a part of the Industrial Boiler MACT reconsideration proposal that was signed on December 2, 2011, is proposing to establish work practice standards for control of dioxins and furans from industrial boilers.

[307] ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

[308] U.S. Department of Energy, Wabash River Coal Gaification Repowering Project. Project Performance Summary; Clean Coal Technology Demonstration Program. DOE/FE–0448. July 2002. EPA–HQ–OAR–2009–0234–2933.

''fossil fuel-fired;'' and (2) is located outside continental U.S.

We are finalizing that the EGU is considered to be ''solid oil-derived fuel-fired'' if (1) the EGU is not a coal-fired EGU and burns solid oil-derived fuel (*e.g.,* petroleum coke, pet coke); and (2) meets the final definitions of ''oil-fired electric utility steam generating unit'' and ''fossil fuel-fired.''

We are finalizing that the EGU is considered to be a ''limited-use liquid oil-fired'' if (1) the EGU meets the final definitions of ''oil-fired electric utility steam generating unit'' and ''fossil fuel-fired;'' and (2) has an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing.

E. What are the requirements during periods of startup, shutdown, and malfunction?

As discussed below in section VI.E., for startup and shutdown, the requirements have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards in lieu of numeric emission limits. Numeric emission limits apply for all other periods for all pollutants, except organic HAP. For malfunctions, the EPA is finalizing an affirmative defense for exceedances of the numerical emission limits that are caused by malfunctions.

F. What are the testing and initial compliance requirements?

We are requiring that you, as an owner or operator of a new or existing coal- or oil-fired EGU, must conduct performance tests to demonstrate compliance with all applicable emission limits. For units using certified continuous emissions monitoring systems (CEMS) that directly measure the regulated pollutant under final 40 CFR part 63, subpart UUUUU (*e.g.,* Hg CEMS, HCl CEMS, HF CEMS, SO_2 CEMS (where an SO_2 limit applies as the alternative equivalent standard)), or sorbent trap monitoring systems, the initial performance test consists of all valid data recorded with the certified monitoring system in the first 30 boiler operating days of data collected with the certified monitoring system prior to the initial compliance demonstration date specified in § 63.10005. A source may also elect to use a PM CEMS to demonstrate compliance with the filterable PM emission limit. If this option is selected, then the same provisions as noted above for other CEMS will apply. (Note that EPA anticipates that the PM monitoring device that may most often will be used is a PM continuous parameter monitoring system (CPMS) in conjunction with an operating limit, as more fully described below.) For units and pollutants not being monitored via CEMS, the owner or operator of an affected unit must perform the initial performance testing in accordance with established EPA reference test methods or the voluntary consensus standard methods incorporated by reference. You, as the owner or operator of an affected unit, must conduct the following compliance tests where applicable:

(1) For coal-fired units, IGCC units, and solid oil-derived fuel-fired units, if you elect to comply with the filterable PM emission limit, you must conduct filterable PM emissions testing using EPA Method 5 from Appendix A to part 60 of chapter 40 to determine initial compliance. Alternatively, if you elect to comply with the total non-mercury HAP metals emission limit or the individual non-mercury HAP metals emissions limits, you must conduct HAP metals testing using EPA Method 29 from Appendix A to part 60 of chapter 40. Note for this rule that the filter temperature for each Method 5 or 29 emissions test must be maintained at 160° ± 14 °C (320 ° ± 25 °F), and the material in Method 29 impingers must be analyzed for metals content. Whenever metals testing is performed with Method 29, you must report the front half and back half analytical fractions separately.

(2) For coal-fired, IGCC, and solid oil-derived fuel-fired units, you must use a Hg CEMS or a sorbent trap monitoring system for both initial compliance and continuous compliance using the continuous Hg monitoring provisions of Appendix A to 40 CFR part 63, subpart UUUUU, except where the low emitting EGU (LEE) requirements apply (see below). The initial performance test consists of all valid data recorded with the certified Hg monitoring system in the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005.

(3) For coal-fired and solid oil-derived fuel-fired units and new or reconstructed IGCC units that employ FGD technology and elect to meet the alternative SO_2 limit in place of the HCl limit, you need not conduct an initial stack test for HCl or SO_2. Instead, the 30 boiler operating days of data collected with the certified SO_2 CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance, and the SO_2 CEMS is used thereafter to demonstrate continuous compliance. If you instead opt to meet the HCl limit and use an HCl CEMS for compliance, you need not conduct an initial stack test for HCl. Instead, the 30 boiler operating days of data collected with the certified HCl CEMS by the initial compliance demonstration date specified in § 63.10005 are used to determine initial compliance. For units not using the SO_2 or HCl CEMS options, you must conduct an initial stack test for HCl using EPA Method 26, 26A, or 320 from Appendix A to part 60 of chapter 40. You may use EPA Method 26 or 320 or ASTM Method D6348–03 (Reapproved 2010) with additional quality assurance if no entrained water droplets exist in the exhaust gas, but you must use Method 26A if entrained water droplets exist in the exhaust gas.

(4) For liquid oil-fired units, you must conduct initial performance testing as follows. If you elect to meet the filterable PM limit instead of the non-mercury metals limit (total or individual), then use Method 5 with the filter material maintained at 160° ± 14°C (320° ± 25°F). Alternatively, you may use a PM CEMS as discussed elsewhere in this preamble. If you elect to meet either the total or individual HAP metals limit, you will use Method 29 for all non-mercury HAP metals. For Hg, conduct emissions testing using EPA Method 29 or 30B from Appendix A to part 60 of chapter 40, or ASTM Method D6784–02 (Reapproved 2008). For acid gases, conduct HCl and HF testing using EPA Method 26A, 320, or 26; or you may elect to comply by using an HCl CEMS and/or an HF CEMS; or under certain conditions you may choose to demonstrate compliance by measuring fuel moisture to demonstrate that moisture content is no greater than 1.0 percent. You must measure daily if fuel is delivered continuously or per shipment if fuel is delivered on a batch basis, or you may use a fuel moisture content certification provided by your fuel supplier. If you use a CEMS, then use the 30 boiler operating days of data collected with the certified monitoring system by the initial compliance demonstration date specified in § 63.10005 to determine initial compliance.

(5) For the required performance stack tests, if you are demonstrating compliance with a heat-input based standard, you must conduct concurrent O_2 or carbon dioxide (CO_2) emission testing using EPA Method 3A or 3B from appendix A to part 60 of chapter 40 or ANSI/ASME PTC 19.10–1981 and then use an appropriate equation, selected from among Equations 19–1

through 19–9 in EPA Method 19 from appendix A to part 60 of chapter 40, to convert measured pollutant concentrations to lb/MMBtu values. Multiply the lb/MMBtu value by one million to get the lb/TBtu value (where applicable). If you choose to meet an electrical output-based emissions limit, you must also collect concurrent stack gas flow rate and electrical production data.

(6) For an existing unit that you believe will qualify as LEE for Hg, you must conduct an initial Method 30B test over 30 days and follow the calculation procedures in the final rule to document a potential to emit less than 10 percent of the applicable Hg emissions limit or less than 29 pounds of Hg per year. If your unit qualifies as a LEE for Hg, you must conduct subsequent performance tests on an annual basis to demonstrate that the unit continues to qualify. For all other pollutants, you must conduct the initial compliance test, and then all other required tests over a 3-year period, and in all such tests, your emission results must be less than 50 percent of the applicable emission limit. If you qualify as a LEE on that basis, you must conduct subsequent performance tests every 3 years to demonstrate that the unit continues to qualify.

(7) You may use results from tests conducted no earlier than 12 months before the compliance date of this rule as the initial performance test for an applicable pollutant, provided that:

a. You certify and keep records demonstrating that no significant changes have occurred,

b. Tests were conducted using methods allowed in this rule in accordance with § 63.10007 and Table 5,

c. You have records of all parameters needed to convert results to units of the standard for the entire period, and

d. For a CEMS-based performance test, you have all the required data for the entire 30-boiler operating day rolling average period.

Operating Limit for PM CEMS

Under the final rule, you may elect to comply continuously with an operating limit, established during the initial performance test, to demonstrate continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. You will use a PM CPMS to monitor compliance with the operating limit. The PM CPMS operating principle must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal. Meeting the operating limit serves as your demonstration of continuous compliance with the filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals limit. As mentioned earlier, if you use this method to demonstrate continuous compliance, you must install a PM CPMS and establish the operating limit during the initial compliance test for filterable PM, total non-mercury HAP metals, or individual non-mercury HAP metals. As noted below, when you use this operating limit, you can reduce stack testing frequency to demonstrate ongoing compliance. You may also opt to install and operate a PM CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively. If you elect to use this option, then the requirements for quarterly testing with Method 5, or annual testing and use of a PM CPMS, are no longer applicable.

Dioxins/Furans and Non-Dioxin/Furan Organic HAP

For dioxins and furans and non-dioxin/furan organic HAP, you must submit documentation that you have conducted a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. The work practice standard involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_X data and may use portable analyzers (which include handheld or similar devices) to monitor and verify the results. The specific details are addressed in 40 CFR 63.10021 of the final rule.

This same work practice standard also applies in place of any emission limits for Hg, non-mercury metals HAP, acid gas HAP, dioxins and furans, and non-dioxin/furan organic HAP from a limited-use, liquid oil-fired EGU (*i.e.,* a unit that has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater). The EPA established this subcategory in response to comments and a further analysis of the units within this subcategory in the ICR database. For these units, EPA believes that the required work practice standards are appropriate and consistent with the requirement of CAA section 112(h).

G. What are the continuous compliance requirements?

To demonstrate continuous compliance with the emission limitations, the final rule includes the following requirements:

(1) *Use of CEMS.* Where a CEMS or a sorbent trap monitoring system is used for demonstrating initial compliance, you also must use the CEMS or sorbent trap monitoring system on a continuous basis to demonstrate ongoing compliance with the numerical emission limits. CEMS or sorbent trap monitoring system data are not used to determine compliance with the work practice standards applicable during periods of startup and shutdown, but sources that install a CEMS or a sorbent trap monitoring system to demonstrate compliance with the numerical emission limits must operate the system at all times, as EPA intends to evaluate the continuous monitoring data from start-up and shutdown periods as discussed below. You must calculate a rolling average for each successive 30-boiler operating day rolling average period. All valid data collected during each successive period will be used to demonstrate compliance, except for data collected during periods of startup and shutdown; during those periods, the owner or operator must meet work practice requirements instead of the numerical emission limits. There is no numerical minimum data availability required to constitute a valid 30-boiler operating day rolling average; however, you must monitor at all times that the process is in operation (including during startups and shutdowns, although emissions during these periods are not included in the 30-boiler operating day average). You must operate, maintain, and quality-assure the CEMS or sorbent trap monitoring systems in accordance with the provisions in 40 CFR 63.10010 and Appendix A and B of the final rule (for Hg, HCl, and HF CEMS), in accordance with Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60 (for PM CEMS used for direct compliance), or in accordance with 40 CFR part 75 (for SO_2 CEMS, and certain ancillary monitors such as a diluent or moisture monitor).

For each unit using HCl, HF, SO_2, PM, or Hg CEMS or a sorbent trap monitoring system for continuous compliance, you must install, certify, maintain, operate and quality-assure the additional CEMS (*e.g.,* CEMS that measure O_2 or CO_2 concentration, stack gas flow rate, and, if default moisture values are not used, moisture content) needed to convert pollutant concentrations to units of the emission standards or operating limits. Where appropriate, you must certify and quality-assure these additional CEMS according to 40 CFR part 75.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to publish a PS specific to HCl CEMS in the near future (prior to the compliance date of this rule). In the meantime, you may petition the Administrator under the procedure given in 40 CFR 63.7(f) for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

When using a sorbent trap monitoring system, you may use each pair of sorbent traps to collect Hg samples for no more than 15 boiler operating days. Under the general duty to monitor at all times, you must replace traps in a timely manner to ensure that Hg emissions are sampled continuously.

For Hg monitoring, the EPA is adding Hg monitoring provisions as Appendix A to 40 CFR part 63, subpart UUUUU, and requiring use of these provisions to document continuous compliance with the rule for coal-fired, IGCC, and solid oil derived-fired units that cannot qualify as LEEs. Appendix A consolidates all Hg monitoring provisions.

Today's rule provides two basic Hg continuous monitoring options: Hg CEMS and sorbent trap monitoring systems. Appendix A requires initial certification and periodic quality assurance (QA) testing of the Hg CEMS and sorbent trap monitoring systems. The certification tests required for the Hg CEMS are a 7-day calibration error test; a linearity check, using NIST-traceable elemental Hg standards; a 3-level system integrity check (similar to a linearity check), using NIST-traceable oxidized Hg standards; a cycle time test; and a relative accuracy test audit (RATA). Table A–1 of Appendix A summarizes the performance specifications for the required certification tests. For ongoing QA of the Hg CEMS, Appendix A requires daily calibrations, weekly single-point system integrity checks, quarterly linearity checks (or 3-level system integrity checks), and annual RATAs. Table A–2 in Appendix A summarizes these ongoing QA test requirements and the applicable performance criteria for Hg CEMS, which are consistent with those published in support of CAMR and are, thus, familiar to the industry.

For sorbent trap monitoring systems, a RATA is required for initial certification, and annual RATAs are required for ongoing QA. The performance specification for these RATAs is the same as for the RATAs of the Hg CEMS. Bias adjustment of the measured Hg concentration data is not required. For day-to-day operation of the sorbent trap system, Appendix A requires you to follow the procedures and QA/QC criteria in PS 12B in Appendix B to 40 CFR part 60. PS 12B is nearly identical to the Appendix K to 40 CFR part 75, published in support of CAMR and with which the industry is familiar. The 40 CFR part 75 concepts of:

a. Determining the due dates for certain QA tests on the basis of ''QA operating quarters'' and

b. Grace periods for certain QA tests apply to both Hg CEMS and sorbent trap monitoring systems. Mercury concentrations measured by Hg CEMS or sorbent trap systems are used together with hourly flow rate, diluent gas, moisture, and electrical load data, to express the Hg emissions in units of the rule, on an hourly basis (*i.e.,* lb/TBtu or lb/GWh). Section 6 of Appendix A provides the necessary equations for these unit conversions.

For HCl and HF CEMS, the EPA is adding monitoring provisions as Appendix B to 40 CFR part 63, Subpart UUUUU. Appendix A references performance specification (PS) 15 of Appendix B to 40 CFR part 60 for Fourier Transform Infrared (FTIR) CEMS for procedures to certify and conduct ongoing quality assurance on these FTIR CEMS. In addition, we expect to promulgate a generic PS specific to HCl CEMS prior to the compliance date of this rule. In the meantime, you may petition the Administrator under the procedure given in 40 CFR 63.7(f) for an alternative approach to compliance monitoring or testing for HCl or any other regulated pollutant.

(2) *Use of stack tests.* If you demonstrate initial compliance on the basis of a stack test, you must demonstrate continuous compliance by conducting periodic stack tests on a quarterly basis. This includes filterable PM (or non-mercury HAP metals) and HCl from coal-fired and solid oil-derived fuel-fired EGUs, and filterable PM (or HAP metals) and HCl and HF from liquid oil-fired EGUs with the following exceptions:

a. If you use a PM CPMS and associated operating limit, you may conduct the applicable Method 5 or Method 29 test once annually rather than quarterly, in which case you must re-establish the operating limit during each performance test. A PM CPMS does not need to meet the requirements for a PM CEMS under PS 11. The final rule includes basic quality checks that the PM CPMS must meet and a requirement for you to develop and follow a site-specific monitoring plan to be approved by the delegated authority. You must demonstrate compliance with the operating limit by using all valid hourly data collected during each successive 30-boiler operating day period rolled daily. The 30-boiler operating day rolling average is calculated by all of the valid hourly average PM CPMS output values collected for the 30 boiler operating days (excluding hours of startup and shutdown; *see* section V.E. of this preamble).

b. If you combust liquid fuels and if your fuel moisture content is no greater than 1.0 percent, you may demonstrate ongoing compliance with HCl and HF emissions limits by:

i. Measuring fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis;

ii. Measuring fuel moisture content daily if your fuel arrives on a continuous basis; or

iii. Obtaining and maintaining a fuel moisture certification from your fuel supplier.

Should the moisture in your liquid fuel be more than 1.0 percent, you must

i. Conduct HCl and HF emissions testing quarterly and establish site-specific monitoring to demonstrate continued acid gas control performance between periodic tests, or

ii. Use an HCl CEMS and/or HF CEMS.

c. If your existing unit qualifies as an LEE for Hg, you must conduct another 30-day Method 30B performance test on your unit once per year to reestablish that the unit continues to qualify as a LEE for Hg. If the results of the LEE test show that the unit exceeds 10 percent of the emissions limit or exceeds the potential to emit 29 pounds of Hg per year, you will lose LEE status for the unit. You can regain LEE status for that unit if every required performance test for a 3-year period shows that emissions from the unit did not exceed the LEE limit. If LEE status is lost for a solid fuel unit, you must commence quarterly performance testing until you install, certify, and operate a Hg CEMS or a sorbent trap monitoring system, and you must complete the installation and certification within 6 months of losing LEE status; for a liquid fuel unit, you must commence quarterly performance testing.

d. If a liquid oil-fired EGU has an annual capacity factor on oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, you must demonstrate continuous compliance with the applicable work practice standard by conducting at least once every 36 calendar months (48 calendar months if a neural network is employed) a combustion process tune-up, a thorough equipment inspection, and an optimization to minimize generation of CO and NO_X, all meeting the requirements of this final rule. You must maintain and inspect the burners and associated combustion controls, tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. You must collect CO and NO_X data using portable analyzers (which typically include handheld or similar devices). Specific details are addressed in 40 CFR 63.10021 of the final rule. In addition, you must record boiler operating hours, by fuel type, in each calendar quarter.

e. The rule allows a grant of LEE status to existing units with test results that show a history of low, non-mercury emissions. As mentioned earlier, LEE status reduces testing frequency for units. After a 3-year period during which every emissions test for a specific pollutant shows emissions no greater than 50 percent of the emissions limit, you may reduce the emissions testing frequency for that specific non-mercury pollutant to once every 36 months. If any subsequent emissions test for that pollutant exhibits emissions greater than 50 percent of the emissions limit, you must revert to the original emissions testing frequency until you re-establish a 3-year period of very low emissions no greater than 50 percent of the standard.

f. For liquid oil-fired units that demonstrate continuous compliance with quarterly performance tests for HCl and HF emission limits rather than through use of HCl and HF CEMS, the final rule requires a site-specific monitoring plan in addition to the quarterly tests. For these pollutants, there is unlikely to be any existing underlying monitoring (such as compliance assurance monitoring) that serves as an additional tool to ensure the source's operations remain consistent with operating conditions during a recent successful performance test. The requirement for a site-specific monitoring plan fills this gap and ensures that in between tests, the source continues to operate in a manner designed to maintain HCl and HF emissions in compliance with the emission limits under this rule. The appropriate parameters to monitor will depend on the compliance strategy employed by a specific source, and thus EPA is enabling the monitoring approach to be established on a case-by-case basis. Given the relatively small number of these units and the other compliance options available, we anticipate that this approach will apply to a small set of units. The monitoring plan will identify the parameters monitored, the monitoring methods, the QA/QC elements that apply, and the data reduction elements (including appropriate averaging periods, as applicable). See 40 CFR 63.10000(c)(2)(ii).

(3) *Work practice standard.* For the performance tune-up work practice requirements, you must demonstrate continuous compliance by conducting the work practice at least once every 36 calendar months (48 calendar months if a neural network is employed). The work practice involves maintaining and inspecting the burners and associated combustion controls, tuning the specific burner type, as applicable, to optimize combustion, obtaining and recording CO and NO_X values before and after burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. A combustion tune-up will involve optimizing combustion of the unit consistent with manufacturer's instruction as applicable, or in accordance with best combustion engineering practice for that burner type.

H. What are the notification, recordkeeping and reporting requirements?

All new and existing sources in all subcategories must comply with certain requirements of the General Provisions (40 CFR part 63, subpart A), which are identified in Table 9 of this final rule. The General Provisions include specific requirements for notifications, recordkeeping, and reporting. You must submit a notification of compliance status report for each unit, according to the schedule required by 40 CFR 63.9(h) of the General Provisions, including a certification of compliance.

Except for units that use CEMS for continuous compliance, under this rule you must provide semiannual compliance reports, as required by 40 CFR 63.10(e)(3) of subpart A, that indicate whether a deviation from any of the requirements in the rule occurred and whether or not any process changes occurred and compliance certifications were reevaluated. As discussed below, we are finalizing a requirement to use the 40 CFR part 75-based Emissions Collection and Monitoring Plan System (ECMPS) for reporting emissions and related data for units using CEMS for most pollutants. Also, as discussed below, for the PM CPMS, PM CEMS, and performance test results, we require you to use EPA's WebFIRE[309] database for reporting.

This rule requires you to keep certain records to demonstrate compliance with each emission limit and work practice standard. The General Provisions to 40 CFR part 63 specify these recordkeeping requirements (see Table 9 to this subpart). Among other specific records, you must keep the following:

(1) All reports and notifications submitted to comply with this rule.

(2) Continuous monitoring data as required in this rule.

(3) Each instance in which you did not meet an emission limit, work practice requirement, operating limit, or other compliance obligation (*i.e.,* deviations from this rule).

(4) Daily hours of operation by each unit.

(5) As part of the general duty to keep all monitoring data, fuel moisture content of liquid fuel, if you elect to demonstrate compliance using that information.

(6) A copy of the results of all performance tests, monitor certifications, performance evaluations, or other compliance demonstrations conducted to demonstrate initial or continuous compliance with this rule.

(7) A copy of your site-specific performance evaluation test plans developed for this rule as specified in 40 CFR 63.8(e), if applicable.

(8) A copy of your acid gas control system parameter monitoring plan under 40 CFR 63.10000(c)(2)(ii).

You also must submit the following additional notifications:

(1) Notifications required by the General Provisions.

(2) Initial Notification no later than 120 calendar days after you become subject to this subpart.

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[309] WebFIRE is the Internet version of FIRE. The Factor Information Retrieval (FIRE) Data System is a database management system containing EPA's recommended emission estimation factors for criteria and HAP. It includes information about industries and their emitting processes, the chemicals emitted, and the emission factors themselves.

(3) Notification of Intent to conduct performance tests and/or compliance demonstration at least 60 calendar days before the performance test and/or compliance demonstration is scheduled.

(4) Notification of Compliance Status 60 calendar days following completion of the performance test and/or compliance demonstration.

Electronic reporting is becoming a common element of modern life (as evidenced by electronic banking and income tax filing), and the EPA is beginning to require electronic submittal of environmental data. Electronic reporting is already common in environmental data collection and many media offices at EPA are reducing reporting burden for the regulated community by embracing electronic reporting systems as an alternative to paper-based reporting.

One of the major benefits of reporting electronically is standardization, to the extent possible, of the data reporting formats that provides more certainty to users of what data are required in specific reports. For example, electronic reporting software allows for more efficient data submittal and the software's validation mechanism helps industry users submit fewer incomplete reports. This alone saves industry report processing resources and reduces transaction times. Standardization also allows for development of efficient methods to compile and store much of the documentation required to be reported by this rule.

Use of Electronic Reporting System

We are requiring that you submit certain reports electronically. In addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with these reports will save industry, state, local, tribal agencies, the public, and the EPA significant time, money, and effort while also improving the transparency and quality of emission inventories and, as a result, air quality regulations.

The reports to be submitted electronically include all performance test reports, notification of compliance status reports, compliance, and continuous monitoring data summaries specified in 40 CFR 63.10031 of this rule. Performance tests are required to be conducted as described in 40 CFR 63.7 of the General Provisions. The data that must be submitted as the performance test report are also described in 40 CFR 63.7. These data must be submitted (except in limited cases) to EPA's WebFIRE database by using the electronic reporting tool (ERT) and the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX), as described below. The data requirements for the notification of compliance status and compliance reports are described in detail in the regulatory text (40 CFR 63.10031) of this rule, but they essentially mirror the requirements in 40 CFR 63.6 of the General Provisions. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX as described below. As required in 40 CFR 63.10031(f)(2) of the final rule, the continuous monitoring summaries are required to be submitted quarterly. The quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the PM CPMS. These reports will also be submitted to WebFIRE using an electronic form found in CEDRI and through the CDX, as described below. This same approach will apply if a source elects to use a PM CEMS or receives approval to use a HAP metals CEMS as an alternative monitoring method.

The availability of electronic reporting for sources subject to the Subpart UUUUU will provide efficiency, improved services, better accessibility of information, and more transparency and accountability. Additionally, submittal of these required reports electronically provides significant benefits for regulatory agencies, industry, and the public. The compliance data electronic reporting system (CEDRI and CDX) is being developed such that once a facility's initial data entry into the system is established and a report is generated, subsequent data submittal will only consist of electronic updates to existing information in the system. Such a system will effectively reduce the burden associated with submittal of data and reports by reducing the time, costs, and effort required to submit and update hard copies of documentation. State, local, and tribal air pollution control agencies will also benefit from having access to the more streamlined and accurate electronic data submitted to the EPA. Electronic reporting will allow for an electronic review process rather than a manual data assessment, making review and evaluation of the source-provided data and calculations easier and more efficient. Electronic reporting will also benefit the public by generating a more transparent review process and increasing the ease and efficiency of data accessibility. Furthermore, electronic reporting will reduce the burden on the regulated community by reducing the effort involved in data collection and reporting activities. In the future, we anticipate there will be fewer and less substantial data collection requests in conjunction with prospective required residual risk assessments or technology reviews. Electronic reporting will substantially reduce this burden, because the EPA will already have these data available and consolidated in an electronic database named WebFIRE. We anticipate that using electronic reporting for the required reports will result in an overall reduction in reporting costs; for a discussion of the economic and cost impacts of electronic reporting, see section XII.D. of this preamble.

Another benefit of electronic data submittal is that these data will greatly improve the overall quality of existing and new emissions factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA will be able to ensure that emission factors, when updated, represent the most current range of operational practices.

Data entry of these electronic reports will be through the CEDRI that is accessed through EPA's CDX (*www.epa.gov/cdx*). Data submitted electronically through CEDRI will be stored in CDX as an official copy of record.

Once you have accessed CEDRI, you will select the applicable subpart for the report that you are submitting. You will then select the report being submitted, enter the data into the form, and click on the submit button. In some cases, such as with submittal of a notification of compliance status report, you will select the report icon, enter basic facility information, and then upload the report in a specified file format.

In addition, we believe that there will be value in allowing other reporting forms to be developed and used in cases where the other reporting forms can provide an alternate electronic file consistent with EPA's form output format. This approach has been used successfully to provide alternatives for other electronic forms (*e.g.*, income tax submittal).

In cases where performance test data are to be submitted to the EPA, you must enter the performance test data and information into the electronic reporting tool (ERT) which can be accessed at *http://www.epa.gov/ttn/chief/ert/index.html.* In CEDRI, the user must then upload the ERT file. CEDRI submits a copy of the ERT project data file directly to WebFIRE where the data are made available. Where performance test reports are submitted, WebFIRE notifies the appropriate state, local, or tribal agency contact that an ERT project data file was received from the source.

Submitting performance test data electronically to the EPA will apply only to those performance tests conducted using test methods that will be supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at the ERT Web site listed above.

I. Submission of Emissions Test Results to the EPA

The EPA has determined that harmonization of the monitoring and reporting requirements of this final rule with 40 CFR part 75 is appropriate, where the affected industry already has a well-defined system for continuous monitoring and reporting of emissions under that part. Therefore, the Agency is finalizing monitoring and reporting requirements for most CEMS that are consistent with 40 CFR part 75. You must report CEMS data (other than PM CEMS data or data from alternative monitoring subject to site-specific approval such as a HAP metals CEMS) to the EPA electronically, on a quarterly basis, using the ECMPS.

The ECMPS process divides electronic data into three categories, the first of which is monitoring plan data. You must maintain the electronic monitoring plan separately and can update it at any time if necessary. The monitoring plan documents the characteristics of the affected units (*e.g.*, unit type, rated heat input capacity, etc.) and the monitoring methodology used for each parameter (*e.g.*, CEMS). The monitoring plan also describes the type of monitoring equipment used (hardware and software components), includes analyzer span and range settings, and provides other useful information. Nearly all coal-fired EGUs are subject to the ARP and thus have established electronic monitoring plans that describe their required SO_2, flow rate, CO_2 or O_2, and, in some cases, moisture monitoring systems. The EPA will adjust the ECMPS monitoring plan format to accommodate this same type of information for Hg, HCl, and HF CEMS, with the addition of a few codes for the new parameters.

The second type of data collected through ECMPS is certification and QA test data. These data include data from linearity checks, RATAs, cycle time tests, 7-day calibration error tests, and a number of other QA tests that are required to validate the emissions data. You may submit the results of these tests to the EPA as soon as you obtain the results, with one notable exception. Daily calibration error tests are not treated as individual QA tests, due to the large number of records generated each quarter. Rather, these tests must be included in the quarterly electronic reports, along with the hourly emissions data. The ECMPS system is set up to receive and process certification and QA data from SO_2, CO_2, O_2, flow rate, and moisture monitoring systems that are installed, certified, maintained, operated, and quality-assured according to 40 CFR part 75. EGUs routinely submit these data to the EPA under the ARP and other emissions trading programs.

To accommodate the certification and QA tests for Hg CEMS, other CEMS, and sorbent trap monitoring systems, the structure and functionality of ECMPS needs relatively few changes, because most of the tests are the same as those required for other gas monitors. For reporting Hg, HCl, SO_2, and HF CEMS data under this rule, we are disabling ECMPS' 40 CFR part 75 bias test (which is required for certain types of monitors under the EPA's SO_2 and NO_X emissions trading programs). The bias adjustment of the data from these monitors is unnecessary for compliance with the rule.

The third type of data collected through ECMPS is the hourly emissions data, which, as previously noted, is reported on a quarterly schedule. You must submit reports within 30 days after the end of each calendar quarter. The emissions data format requires hourly reporting of all measured and calculated emissions values, in a standardized electronic format. You must report direct measurements made with CEMS, such as gas concentrations, in a Monitor Hourly Value (MHV) record. A typical MHV record for gas concentration includes data fields for:

(1) The parameter monitored (*e.g.*, SO_2);

(2) The unadjusted and bias-adjusted hourly concentration values (note that if bias adjustment is not required, only the unadjusted hourly value is reported);

(3) The source of the data, *i.e.*, a code indicating either that each reported hourly concentration is a quality assured value from a primary or backup monitor, or that quality-assured data were not obtained for the hour; and

(4) The percent monitor availability (PMA), which is updated hour-by-hour. This generic record structure could easily accommodate hourly average measurements from CEMS used under this rule.

The ECMPS reporting structure is quite flexible, which makes it useful for assessing compliance with various emission limits. The Derived Hourly Value (DHV) record allows calculations of a wide variety of quantities from the reported hourly emissions data. For instance, if an emission limit is expressed in units of lb/MMBtu, the DHV record can be used to report hourly pollutant concentration values in these units of measure, since the lb/MMBtu values can be derived from the hourly pollutant and diluent gas (CO_2 or O_2) concentrations reported in the MHV records. The ECMPS can also accommodate multiple DHV records for a given hour in which more than one derived value is required to be reported. The system will support reporting hourly data in the units of the emission standards (*e.g.*, lb/MMBtu, lb/TBtu, lb/GWh, etc.) when hourly Hg concentration data are reported through ECMPS using the DHV record, in conjunction with the appropriate equations and auxiliary information such as heat input and electrical load (all of which are reported hourly in the emissions reports).

One change in this rule from standard 40 CFR part 75 emissions data reporting is elimination of the requirement to provide substitute data calculations within ECMPS. The ARP and other emissions trading programs that report emissions data to the EPA using 40 CFR part 75 require provision of a complete data record. Emissions data are required to be reported for every unit operating hour. When CEMS are out of service, substitute data must be reported to fill in the gaps. However, for the purposes of compliance with a NESHAP, reporting substitute data during monitor outages is not necessary, as quantification of total mass emissions is not the focus of the rule. Hours when a monitoring system is out of service would be counted as hours of monitor down-time and may be a deviation from the monitoring requirements of this rule unless the rule provides an exception, as it does for routine quality control and maintenance activities.

In contrast to the CEMS-related data that would be submitted through ECMPS, you must submit reports of performance tests and PM CPMS data to EPA's WebFIRE database by using CEDRI that is accessed through EPA's

CDX (*www.epa.gov/cdx*). You must submit performance test data in the file format generated through use of EPA's ERT (see *http://www.epa.gov/ttn/chief/ert/index.html*) within 60 days of performance test completion. Electronic data submittal requirements are described in section V.H. of this preamble.

Other notifications and reports not currently accepted by the electronic reporting system will be submitted in hardcopy form at this time.

VI. Summary of Significant Changes Since Proposal

The previous section described the requirements that EPA is finalizing in this rule. This section will discuss in greater detail the key changes EPA is making from the proposed. These changes result from EPA's review of the additional data and information provided to us and our consideration of the many substantive and thoughtful comments submitted on the proposal. While our approach and methodology to establishing the standards remain the same, the changes make the final rule more flexible and cost-effective, reduce reliability concerns and improve clarity, while fully preserving, or improving, the public health and environmental protection required by the CAA.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability provisions of the final rule to provide clarity. These changes do not change the universe of sources subject to the rule.

The EPA is revising a number of the proposed definitions and adding a definition for ''natural gas-fired electric utility steam generating unit'' in the final rule to provide clarity to the regulated community concerning the standards applicable to coal- and oil-fired EGUs.

In the proposed rule, the EPA defined ''[e]lectric utility steam generating unit'' consistent with the CAA section 112(a)(8) definition:

> A fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

40 CFR 63.10042.

We also indicated how we would determine whether units were coal-fired or oil-fired fired EGUs: ''If an EGU burns coal (either as a primary fuel or as a supplementary fuel), or any combination of coal with another fuel (except solid waste as noted below), the unit is considered to be coal fired under this proposed rule. If a unit is not a coal-fired unit and burns only oil, or oil in combination with another fuel other than coal (except as noted below), the unit is considered to be oil fired under this proposed rule.'' 76 FR 25020.

We proposed a definition for the term ''fossil fuel-fired'' because that term was not defined in the statute and we wanted to clarify the level of fossil fuel combustion necessary to satisfy the CAA section 112(a)(8) definition of EGU. The definition focused on coal and oil combustion because the EPA was only regulating coal- and oil-fired EGUs in this final rule. The proposed definition contained two primary elements: (1) the unit must be capable of combusting sufficient amounts of coal or oil to generate the equivalent of 25 megawatts electrical output; and (2) the unit must have fired coal or oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years. 76 FR 25025. We further stated that for a unit to be ''capable of combusting'' coal or oil the unit must have a permit that authorized the combustion of coal or oil and also have the appropriate fuel handling facilities on-site. *Id.*

As explained in the proposed rule, natural gas-fired EGUs were not included in the December 2000 listing so such units that otherwise met the CAA section 112(a)(8) definition of EGU because of natural gas combustion are not subject to the final rule. In the proposed rule, we stated that an EGU that ''combusts natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous 3 calendar years or 85.0 percent or more of the annual heat input during any one of those calendar years'' was not subject to the rule. *Id.* The references to 90 percent natural gas combustion over 3 years and 85 percent natural gas combustion in any one year were included to align with the definitions of ''fossil fuel-fired'' so that it would be clear that units combusting primarily natural gas would not be considered coal-fired, oil-fired, or IGCC EGUs if they burned 10 percent or less of coal, oil, or synthetic gas derived from coal or solid oil over 3 years or 15 percent or less of such fuels in any one year. We did not intend to suggest that to be considered a fossil fuel-fired EGU a natural gas-fired unit that is not a coal-fired or oil-fired EGU would have to combust natural gas that exceeded the 10 percent/15 percent thresholds set forth in the proposed rule. In fact, in 40 CFR 63.9983 of the proposed rule, we stated that ''[a]ny EGU that is not a coal- or oil-fired EGU and combusts natural gas more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years'' is not subject to this subpart.

We further explained that the percentages included in the definition of ''fossil fuel-fired'' would prevent units that primarily combusted fuels other than fossil fuels from being subjected to the final rule:

> Units that do not meet the definition of fossil-fuel fired would, in most cases, be considered IB units subject to one of the Boiler NESHAP. Thus, for example, a biomass-fired EGU, regardless of size, that utilizes fossil fuels for startup and flame stabilization purposes only (*i.e.,* less than or equal to 250 MMBtu/hr and used less than 10.0 percent of the average annual heat input during the previous 3 calendar years or less than 15.0 percent of the annual heat input during any one of those calendar years) is not considered to be a fossil fuel-fired EGU under this proposed rule. The EPA has based its threshold value on the definition of ''oil-fired'' in the ARP found at 40 CFR 72.2. As EPA has no data on such use for (*e.g.*) biomass co-fired EGUs because their use has not yet become commonplace, we believe this definition also accounts for the use of fossil fuels for flame stabilization use without inappropriately subjecting such units to this proposed rule. *Id.*

Thus, in the proposed rule, we intended to create thresholds to determine when a unit is fossil fuel-fired and for which fossil fuel the unit is fossil fuel-fired. We intended to include a unit combusting more than the defined amount of coal in one of the coal-fired EGU subcategories. If a unit is not coal-fired and it is combusting more than the defined amount of oil, we intended to include the unit in one of the oil-fired EGU subcategories. We also intended to make clear that EGUs that are neither coal-fired nor oil-fired but combust more than the defined amount of natural gas are natural gas-fired EGUs not subject to the final standards. However, the definitions, as proposed, were not sufficiently descriptive.

For example, we included a definition for ''coal-fired electric utility steam generating unit'' that did not include the requirement that the unit must combust coal for at least 10 percent of the heat input over 3 years or 15 percent of the heat input in any one year. Instead, in the proposed rule we indicated that a unit was coal-fired if it burned coal in any amount. We did not intend to define a unit as coal-fired if it burned coal that accounted for 10 percent or less over 3 years or 15 percent of less in any one year, as that would be inconsistent with the definition of fossil fuel-fired and the definitions for the oil-fired EGU subcategories. Under the proposed rule construct, a unit that combusts mostly biomass and less than 10 percent coal over 3 years would not be a coal-fired EGU because it would not meet the ''fossil fuel-fired'' definition. But a unit burning mostly petroleum coke and less than 10 percent coal over 3 years might be considered a coal-fired EGU because it would meet the definition of ''fossil fuel-fired'' and be burning some coal, even though that level of coal combustion alone would not be sufficient to make the unit ''fossil fuel-fired'' for coal. That result is at odds with our intent. The same would hold true for an EGU that combusts mostly natural gas and less than 10 percent synthetic gas derived from coal over a 3-year period. Our proposal preamble makes clear that we did not intend this result because we specifically stated that units burning 90 percent or more natural gas over a 3-year period would be considered natural-gas fired EGUs. 76 FR 25025.

In addition, we proposed to define ''[u]nit designed to burn solid oil fuel subcategory'' to include any EGU that burned a solid fuel derived from oil for more than 10.0 percent of the average annual heat input during the previous 3 calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years, either alone or in combination with other fuels. We also included the 10 percent/15 percent thresholds in the definition for the liquid oil subcategory, but, as stated above, we did not include the thresholds in the definition of ''coal-fired'' EGU. Therefore, there would be some confusion for a source that blended coal with solid oil derived fuel (*e.g.,* petroleum coke). For example, the owner or operator of an EGU that burned sufficient solid oil-derived fuel that accounted for 80 percent of the heat input in a given year and the remainder of the fuel was coal would not be sure which standard applied because the definitions in the proposed rule were internally inconsistent.

For these reasons, we are revising the definitions for ''coal-fired electric utility steam generating unit,'' ''integrated gasification combined cycle electric utility steam generating unit,'' and ''oil-fired electric utility steam generating unit,'' and we are adding a definition of ''natural-gas fired electric utility steam generating unit'' as set out in 40 CFR 63.10042.

In addition to these changes, we are revising the definition of ''fossil fuel-fired'' based on comments. We are revising the definition to remove the heat input equivalent of 25 MW because commenters noted that the equivalency used (taken from 40 CFR part 60, subpart Da) could not be applied consistently because of differing boiler efficiencies. Commenters noted that owners/operators were familiar with the use of the ''MW'' term for the boilers and boilers include nameplate capacities that are readily identifiable.

We are also including a revision to the definition so that the fossil fuel combustion thresholds of 10 percent over 3 consecutive years and 15 percent in one year are evaluated after the applicable compliance date of the final rule on a rolling basis. Commenters correctly noted that some existing coal- and oil-fired EGUs will convert their units to alternative fuels (*e.g.,* natural gas or biomass) and if the definition were finalized as proposed such units could be improperly subjected to the final standards.

The new definition is set out in 40 CFR 63.10042.

For clarity, we are also removing the definition of ''[u]nit designed to burn liquid oil fuel subcategory,'' revising the definition of ''[u]nit designed to burn solid oil fuel subcategory,'' adding definitions for the continental and non-continental liquid oil-fired EGU subcategories, and adding a definition of a limited-use liquid oil-fired EGU as set out in 40 CFR 63.10042.

In the proposed rule, we stated that we believed EGUs may at times not meet the definition of an EGU subject to this subpart. For example, we explained that there may be some cogeneration units that are determined to be covered under the Boiler NESHAP. Such unit(s) may make a decision to increase the proportion of production output being supplied to the electric utility grid, thus causing the unit(s) to meet the EGU cogeneration criteria (*i.e.,* greater than one-third of its potential output capacity and greater than 25 MW). In the preamble to the proposed rule, we indicated that a unit subject to one of the Boiler NESHAP that increases its electricity output and meets the definition of an EGU would be subject to the EGU NESHAP for the 6-month period after the unit meets the EGU definition.[310] 76 FR 25026. Assuming the EGU did not meet the definition of an EGU following that initial occurrence, at the end of the 6-month period it would revert back to being subject to the Boiler NESHAP, or other applicable standard. We solicited comment on the extent to which situations like this might occur, how the EPA should address situations where units change applicability, and whether we should include provisions similar to those included in the final CISWI (40 CFR 60.2145) to address such situations. *Id.*

Several commenters asked the Agency to include provisions in the final rule that would address situations like the ones described in the preamble to the proposed rule. Because applicability to the final rule is based in part on the statutory definition of an EGU is CAA section 112(a)(8), similar to the situation with units combusting solid waste under CAA section 129(g)(1) (*e.g.,* CISWI Rule), we are adopting provisions in the final rule that are based on the fuel switching provisions of the final CISWI Rule (*See* Final CISWI Rule, 40 CFR 60.2145). For example, a cogeneration unit that did not historically provide more than one third of its potential electrical output capacity to a power distribution system could change its output and provide more than 25 megawatts electrical output to any power distribution system for sale. Such units would be subject to MATS. If the cogeneration unit later reduced its output such that it no longer met the definition of an EGU, that source would nevertheless remain subject to MATS for at least 6 months from the date that the unit first qualified as an EGU.

In addition, we are finalizing a provision whereby you may opt to remain subject to the provisions of this final rule, unless you combust solid waste, in which case you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.,* 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units), or subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units)). We believe the provision to opt to remain subject to this final rule will ameliorate conditions where EGUs may potentially move between NESHAP on a relatively frequent basis. Notwithstanding the provisions of this final rule, an EGU that starts combusting solid waste is subject to standards under CAA section 129, and the unit remains subject to those standards until the unit no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

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[310] Although we clearly stated the intent to require sources to comply for 6 months after meeting the definition of an EGU, we inadvertently failed to include the provision in the proposed rule.

The changes to the definitions described above provide clarity to sources, permitting agencies, and the public about the applicability of the rule and help ensure that sources are appropriately covered by the regulation.

B. Subcategories

In this final rule, the EPA is adding subcategories for limited-use oil-fired units and non-continental oil-fired units and revising the definitions for the coal-fired EGU subcategories.

The proposed rule subcategorized EGUs burning coal into two subcategories: EGUs designed for coal ≥8,300 Btu/lb and EGUs designed for virgin coal <8,300 Btu/lb (low rank virgin coal). We received a number of comments indicating that the definition of the low rank virgin coal subcategory was technically deficient.

Under CAA section 112(d)(1), the Administrator has the discretion to ''* * * distinguish among classes, types, and sizes of sources within a category or subcategory in establishing * * *'' standards. The EPA maintains that, normally, any basis for subcategorization (*i.e.,* class, type, or size) must be related to an effect on HAP emissions that is due to the difference in class, type, or size of the units. *See* 76 FR 25036–25037. The EPA believes it is not reasonable to exercise our discretion without such a difference because if sources can achieve the same level of emissions reductions notwithstanding a difference in class, type, or size, the purposes of CAA section 112 are better served by requiring a similar level of control for all such units in the category or subcategory. *See Lignite Energy Council* v. *EPA,* 198 F. 3d 930, 933 (D.C. Cir. 1999) (''EPA is not required by law to subcategorize—section 111[b][2] merely states that 'the Administrator *may* distinguish among classes, types, and sizes within categories of new sources''' (emphasis original)); *see* also CAA section 112(d)(1) (containing almost identical language to CAA section 111, CAA section 112(d)(1) provides that ''the Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing [ ] standards * * *''). Even if we determine that emissions characteristics are different for units that differ in class, type, or size, the Agency may still decline to subcategorize if there are compelling policy justifications that suggest subcategorization is not appropriate. *Id.*

When developing the proposed rule, we examined the EGUs in the top performing 12 percent of sources for Hg emissions. We determined that:

> There were no EGUs designed to burn a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 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 bigger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories. For all other HAP from these two subcategories of coal-fired units, the data did not show any difference in the level of the HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for the other HAP. 76 FR 25036–67.

Based on this determination, we proposed to establish two subcategories with separate Hg limits. Comments on the proposed rule indicate that we correctly identified the EGUs that should be included in each subcategory, but the comments also demonstrated that we made certain incorrect conclusions that require us to revise the definitions of our coal-fired EGU subcategories. The revised definitions ensure that the EGUs we identified at proposal as having different Hg emissions remain in one subcategory.

As stated above, we believed at proposal that the boiler size was the cause of the different Hg emissions characteristics that led us to propose subcategorization, but many commenters indicated that it was not the boiler size but the fact that the EGUs burned a nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) (low rank virgin coal) that causes the disparity in Hg emissions. Several commenters indicated that their EGUs were designed to burn and burned low rank virgin coal but the units did not meet the height-to-depth ratio that EPA proposed. For example, the height-to-depth ratio of certain EGUs in this subcategory is in fact 3.5, not 3.82. Further, there are other EGUs in this subcategory that are circulating fluidized bed (CFB) combustion units which do not meet the height-to-depth ratio parameters in the proposed rule, nor are they anything like the pulverized coal (PC) EGUs we initially identified as having the 3.82 height-to-depth ratio.

In addition to the comments concerning EGUs firing this coal, we received comments from at least two commenters indicating that the EPA should clarify in which subcategory a unit belongs when it does not burn low rank virgin coal but is designed to combust low rank virgin coal and has a height-to-depth ratio of greater than 3.82. Commenters also indicated that CFB units that are burning coal-refuse[311] or other nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of 19,305 kJ/kg (8,300 Btu/lb) or greater are ''designed to burn'' any type of coal. Owners of CFB units that are not firing low rank virgin coal asked which subcategory they belong to based on their ability to burn any type of coal (including low rank virgin coal) without modification. These commenters also indicated that some coal refuse that is combusted has a heating value less than 8,300 Btu/lb but is not ''virgin coal.'' It was unclear to which subcategory they belonged since the proposed rule did not in fact require the unit to burn any specific coal, instead only requiring the unit be ''designed'' to burn lower Btu coal.

Based on the comments received, we reevaluated the subcategory definitions because we were concerned that the definitions we proposed would improperly categorize a number of the EGUs in both subcategories. We concluded that we should not maintain the proposed definition for ''[u]nits designed for coal <8,300 Btu/lb'' and exclude the CFB units and PC EGUs with a height-to-depth ratio less than 3.82 that combusted low rank virgin coal.

We were equally concerned that the subcategory definitions not be revised in a manner that would move EGUs that we believed the data show could comply with a more stringent standard into a subcategory with a less stringent standard because, aside from the type of EGUs we identified, all other classes, types, and sizes of EGUs were represented among the top performing 12 percent for Hg in the ≥8,300 Btu/lb subcategory. We were particularly concerned about the CFB units because other CFB units are well represented among the best performing EGUs for Hg in the ≥8,300 Btu/lb subcategory, but the CFB units burning low rank virgin coal are not achieving the same levels of Hg emissions control. Including the best performing CFB units from the other subcategory in the low rank virgin coal subcategory would likely lead to a Hg standard as stringent as the standard for

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[311] It is our understanding that no unit combusts coal-refuse from nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb).

EGUs in the ≥8,300 Btu/lb subcategory because the CFB units from the other subcategory would be used to establish the floor. We believe that result would be inconsistent with the intent of the proposed rule. We were also concerned about the information that some EGUs that fired low rank virgin coal had a height-to-depth ratio of 3.5, not 3.82, and that some EGUs that fired other ranks of coal had a height-to-depth ratio greater than 3.82. For these reasons, we did not revise the definition to include CFB units and PC EGUs with a height-to-depth ratio greater than 3.5.

After fully considering the available information, including the comments received, we have concluded that it is appropriate to continue to base the subcategory definitions, at least in part, on whether the EGUs were designed to burn and, in fact, did burn low rank-virgin coal, but that it is not appropriate to continue to use the height-to-depth ratio criteria because that approach would potentially exclude EGUs we identified as having different Hg emission characteristics and include EGUs that did not have different emissions characteristics. We recognize that some commenters have taken the position that it is unlawful to subcategorize based on factors such as fuel type but nothing in the statute prohibits such an approach and the case law supports this approach to the extent courts have considered subcategorization based on such factors. *See Sierra Club* v. *Costle,* 657 F. 2d 298, 318–19 (D.C. Cir. 1981) (differing pollutant content of input material can justify a different standard based on subcategorization authority to ‘‘distinguish among classes, types and sizes within categories of new sources’’). Furthermore, we believe had Congress intended to prohibit the EPA from subcategorizing based on an EGU being designed to use and using a certain material input (*e.g.,* fuel) it would have clearly stated such intent in the CAA. However, we believe the Agency could decline to exercise its discretion to subcategorize even if the potential result would be the prohibition of the use of some materials if the circumstances warranted. We note that even if we did not subcategorize on the final basis selected, the Hg emissions standard of 1.2E0 lb/Tbtu for the ‘‘unit designed for coal ≥8,300 Btu/lb’’ would remain the same.

We considered basing the subcategory solely on an EGU being designed to burn and burning low rank virgin coal. We decided not to do so because we were concerned that such a definition would allow sources to potentially meet the definition by combusting very small amounts of low rank virgin coal. For example, an EGU on the east coast (or any other region) that was not designed to burn and did not routinely burn low rank virgin coal could import one truck full of low rank virgin coal and burn a very small quantity of it periodically to meet the subcategory definition. To avoid creating this potential loophole, we considered other characteristics that would distinguish EGUs combusting low rank virgin coal.

We determined that these EGUs are universally constructed ‘‘at or near’’ a mine containing low rank virgin coal because it is not cost-effective to transport large quantities of such fuel long distances. Furthermore, we believe that this subcategory of EGUs are almost always built at a mine and limited transportation of the coal is only required as the mine face moves over the course of time. Many such EGUs construct dedicated rail lines, private roads, or conveyor systems to transport the coal to the EGU as the mine face moves. We obtained information from data acquired to develop the CSAPR indicating that the longest distance any EGU firing low rank virgin coal transports that coal is 40 miles. We believe that this distance is near the outer limits for the transport of such coal, but, even for those EGUs, the EGUs were constructed closer to a now idle mine or closer to the working face of a mine that has now expanded away from the EGU site. For these reasons, we are including a requirement that the unit be constructed and operated at or near a mine containing the low rank virgin coal it burns.

We are revising the coal-fired EGU subcategory definitions as set out in 40 CFR 63.10042.

We believe the revised subcategory definitions are reasonable for all the reasons set forth above. The revised definitions maintain the EGUs we identified as having different Hg emissions characteristics in one subcategory and the definitions prevent other EGUs that are not firing low rank virgin coal from being required to comply only with the less stringent Hg emission standard.

As discussed in response to comments, we do not believe that additional subcategorization of other coal-fired EGUs is reasonable or appropriate. All other coal-fired EGUs that are not designed to burn and are burning low rank virgin coal are represented among the best performing sources for Hg, such that no argument exists to support that the Hg emissions from those EGUs are different. In any case, even if emissions are somewhat different as some commenters suggest, we would decline to exercise our discretion because the data demonstrate that the best performing EGUs designed to burn and burning all other ranks of coal are able to achieve the MACT level of control using currently available controls and other HAP emission reduction mechanisms (*e.g.,* coal washing) for the ≥8,300 Btu/lb subcategory.

A second issue related to subcategorization concerns non-continental liquid oil-fired EGUs. At proposal, the EPA did not have sufficient emissions data from non-continental liquid oil-fired EGUs upon which to base a subcategory and took comment on the issue. The data have since been provided in response to the ICR and we received comments suggesting that a non-continental subcategory is appropriate based on the location of such units, the limited availability of alternative fuel sources, and the fact that the emissions characteristics of such units are distinct from continental liquid oil-fired EGUs. The EPA has evaluated the data and comments and we agree that a subcategory is warranted based for the reasons suggested by the commenters. Therefore, the Agency is finalizing the liquid oil-fired EGU subcategories of ‘‘continental’’ and ‘‘non-continental.’’

Lastly, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal because some sources required to test under the ICR did not submit the data until after proposal. We took comment on whether a limited-use subcategory was warranted. Commenters indicated that their units were a different class and type of units because many of them were only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.,* they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate. Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-fired EGUs as discussed further elsewhere in this preamble.

C. Emission Limits

The proposed rule included numerical emission limits for PM, Hg, HCl, HF, SO_2, total HAP metals, and individual HAP metals, depending on the subcategory and specific situation. These proposed limits resulted from calculations of MACT floors using information and data available to the Agency prior to proposal, as required by CAA section 112. Based on information and data received during the comment period, we have made data and calculation corrections where necessary and then re-ranked the best performing units in the MACT floor pools. Based on the new ranking, a limited number of the emission limits in the final rule have changed from those proposed.

In addition to adjustments to the emission limits themselves, we are finalizing several other changes to the emission standards that will simplify and improve compliance for sources without compromising the toxics reductions achieved. One key change, as discussed elsewhere in this notice, is that we have changed the surrogate for non-mercury metallic HAP from total particulate matter (PM) to filterable PM for coal-fired and solid oil-derived EGUs. This change is based on information provided in comments and our own conclusion that measurement of filterable PM provided assurance of equivalent HAP emissions control. Most of the non-mercury metal HAP, for which PM is a surrogate, are filterable PM and the one that is not (Se) is well controlled by the limit on acid gases. Using filterable PM as the surrogate will allow us to use continuous PM monitoring systems, which measure filterable (but not total) PM, thereby providing a more continuous measure of compliance.

For liquid oil-fired EGUs, based on comments received and corrections made to the data submitted, we have added a filterable PM limit in the final rule as an alternative equivalent standard for the total metal-HAP limit in the proposed rule. In addition, as discussed elsewhere in this notice, we have added measurement of the moisture content of the oil (with a 1 percent limit) as an alternate compliance assurance measure for liquid oil-fired EGUs for determining compliance with the HCl and HF limits. Direct measurement of HCl and HF remains a compliance demonstration method in the final rule. Finally, as discussed in section VI.D of this notice, the final work practice standard consisting of burner tune-ups, much like those required for organic HAP control, for those limited-use liquid oil-fired EGUs whose annual capacity factor is less than 8 percent.

D. Work Practice Standards for Organic HAP Emissions

As noted earlier in section V.D., the final rule includes a work practice standard for organic HAP, including dioxins and furans, applicable to all EGUs. As noted in section V.D. above, the majority of emissions of these pollutants are below the detection levels of EPA test methods and, therefore, are impractical to measure. The work practice standard, described below, is a practical approach to ensuring that equipment is maintained and run so as to minimize emissions of dioxins and furans, and we expect it to be more effective than establishing a numeric standard that cannot reliably be measured or monitored. The work practice also applies to the limited-use liquid oil-fired subcategory included in the final rule.

The work practice involves maintaining and inspecting the burners and associated combustion controls (as applicable), tuning the specific burner type to optimize combustion, obtaining and recording CO and NO_X values before and after the burner adjustments, keeping records of activity and measurements, and submitting a report for each tune-up conducted. In Table 3 of the final regulation, we have clarified that this refers to performance tune-ups, not tests, and have addressed the frequency requirement as discussed in response to comments about the appropriateness of the 18-month frequency. The provisions of 40 CFR 63.10006(h)(i) refer to 40 CFR 63.10021(e) for the specific steps required to be part of the periodic tune-up. We have also adjusted the language in the final rule to recognize the value of automated boiler optimization tools such as neural network systems.

Under the final rule, the tune-up must be conducted at each planned major outage and in no event less frequently than every 36 calendar months, with an exception that if the unit employs a neural-network system for combustion optimization during hours of normal unit operation, the required frequency is a minimum of once every 4 years (48 calendar months). Initial compliance with the work practice standard of maintaining burners must occur within 180 days of the compliance date of the rule. The initial compliance demonstration for the work practice standard of conducting a tune-up may occur prior to the compliance date of the rule, but must occur no later than 42 months (36 months plus 180 days) from the compliance date of the rule or, in the case of units employing neural network combustion controls, 54 months (48 months plus 180 days). If the tune-up occurs prior to the compliance date of the rule, you must maintain adequate records to show that the tune-up met the requirements of this standard.

We have made a number of specific changes to address what to do for repairs that may require longer term corrective actions, additional methods for evaluating combustion effectiveness, and clarification on procedures for recording CO and NO_X information. There were specific comments that opposed the reference to manufacturer specifications, if available. We retained this language in the final rule, but note that these specifications apply only to the extent applicable. Specifically, if manufacturer specifications only address equipment or conditions that are no longer present given current boiler operations, then those specifications are not applicable and other combustion engineering best practice procedures for that burner type would apply. We have also clarified that portable emission monitoring equipment may be used to collect the required emissions optimization data regarding pre- and post-tune-up CO and NO_X emission levels.

E. Requirements During Startup, Shutdown, and Malfunction

We proposed numerical emission standards that would apply at all times, including during periods of startup, shutdown, and malfunction. Although at proposal we stated that we were not setting a different standard for startup and shutdown, we did propose different standards for startup and shutdown by our inclusion of the default values described below, which applied only during startup and shutdown. Specifically, we stated:

> To appropriately determine emissions during startup and shutdown and account for those emissions in assessing compliance with the proposed emission standards, we propose use of a default diluent value of 10.0 percent O_2 or the corresponding fuel specific CO_2 concentration for calculating emissions in units of lb/MMBtu or lb/TBtu during startup or shutdown periods. For calculating emissions in units of lb/MWh or lb/GWh, we propose source owners use an electrical production rate of 5 percent of rated capacity during periods of startup or shutdown. We recognize that there are other approaches for determining emissions during periods of startup and shutdown, and we request comment on those approaches. We further solicit comment on the proposed approach described above and whether the values we are proposing are appropriate.

We proposed application of the respective emission limits during periods of startup and shutdown and use of default values to calculate the emission limits. The standards that apply at all times other than startup and shutdown are production-based limits, which is why we proposed the default values. The default values were meant to account for the fact that during startup and shutdown events, production (in this case the generation of electricity) is by definition nonexistent. Thus, in effect, we proposed a separate standard to apply during startup and shutdown.

We received a variety of comments on the proposed standards that would apply during startup and shutdown. Many commenters pointed to the lack of data in the record concerning emissions that occur during periods of startup and shutdown. They further asserted that emissions during these periods can be highly variable in light of the sequence of events that occurs during the startup and shutdown of an EGU. Although a number of commenters supported the use of the diluent factor approach, including the default 5 percent of rated capacity, during startup/shutdown periods, other commenters questioned the feasibility of collecting additional data during such periods and had concerns regarding the reliability of measurements obtained from EGUs during such periods.

In response to the Agency's ICR to the utility industry, seven owners or operators indicated that they provided startup and shutdown data for their EGUs. These data were submitted in response to the requirement in the ICR to provide all available data from the 5 years prior to the date the ICR was issued. Of these data, there were almost no HAP data for startup and shutdown periods and almost all of the data failed to meet our data quality requirements.[312] Thus, we do not have sufficient data on emissions that occur during startup and shutdown on which to set emission standards. We are therefore establishing work practice standards rather than numeric emissions standards for periods of startup and shutdown in the final rule. Before we describe those work practices, we first address what constitutes startup and shutdown.

Several commenters had an expansive view of what constitutes startup and shutdown. We disagree with these commenters that asserted that periods of ''load swings'' should be considered ''startup'' or ''shutdown,'' as they are generally routine, normal operations with production (*i.e.,* generation of electricity) taking place. We maintain that the standards as promulgated account for any variability in emissions that may occur during these periods over a 30-day averaging period, and commenters have provided no data that cause us to doubt that determination. We have included definitions of startup and shutdown in the final rule that are consistent with the definitions in the proposed rule. At proposal, we defined startup as the setting in operation of an affected source or portion of an affected source for any purpose, and shutdown as the cessation of operation of an affected source or portion of an affected source for any purpose.

Commenters sought more clarity regarding the meaning of these terms as applied to EGUs, so we are revising the definitions in the final rule as set out in 40 CFR 63.10042.

These interpretations are tailored for EGUs and are consistent with the definitions of ''startup'' and ''shutdown'' contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that EGUs function to provide electricity primarily for sale to the grid but also at times for use on-site; therefore, EGUs should be considered to be operating normally at all times electricity is generated. We further believe these revised definitions address what some commenters describe as ''warm'' and ''hot'' startups as long as the EGU is shutdown (*i.e.,* no fuel fired and no electricity generation) prior to the ''warm'' or ''hot'' startup period.

As for the work practices, in this final rule, the EPA is requiring sources to operate using either natural gas or distillate oil for ignition during startup. The EPA also is requiring sources to vent emissions to the main stack(s) and operate all control devices necessary to meet the normal operating standards under this final rule (with the exception of dry scrubbers and SCRs) when coal, solid oil-derived fuel, or residual oil is fired in the boiler during startup or shutdown. It is the responsibility of the operators of EGUs to start their dry scrubber and SCR systems appropriately to comply with relevant standards applicable during normal operation.

The EPA carefully considered fuels and potential operational constraints of air pollution control devices (APCDs) when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning natural gas or distillate oil for longer portions of startup or shutdown periods, if needed, at a boiler, and the HAP emission reduction benefits warrant additional utilization of such fuels until the temperature and stack emissions pressure is sufficient to engage the APCDs. The EPA is aware that SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_X reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of EGUs to start their SCR and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

Some commenters have asserted that firing of fuel oil during periods of startup and shutdown constrains operation of PM controls (ESPs and baghouses) because under cooler conditions, acids and tars can condense on surfaces in these controls. The commenters assert that such condensation can cause detrimental impacts on hardware and operation of these controls, and could cause safety concerns. The EPA understands that concerns with acidic and tarry deposits are related to firing of heavy (residual) oil and not distillate oil. Accordingly, with residual fuel oil firing, site-specific flue gas temperature and oxygen (O_2) concentration thresholds may be applicable to minimize condensation of acids and tars and thereby minimize any potential for detrimental impacts on hardware and any safety concerns.

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[312] In response to the ICR, we also received SO_2 CEMS data and the Agency had additional SO_2 CEMS data available through the CAMD ARP database. We are not able to identify specific periods of start-up and shutdown in either the ICR CEMS data or the CAMD ARP data, and the ICR respondents do not indicate that the ICR data includes periods of startup and shutdown. We set the emission limits for SO_2 and HCl using the data provided to the EPA from the 2010 ICR, not the CAMD data, since those data were taken concurrently under the same specified operating conditions using the same fuel. We used the SO_2 CEMS data that was submitted in response to the ICR by converting it to single point data to correlate to the data from units that did not provide CEMS data from the relevant testing period. The emissions limits for the NESHAP incorporated variability by applying the 99 percent UPL to the average emissions developed from the stack test data and SO_2 CEMS data that was converted to stack test data. Thus, we did not have data on which to establish an SO_2 standard during periods of startup and shutdown and the numeric standards do not apply to those periods in the final rule. In contrast, the NSPS for SO_2 is applicable during periods of startup and shutdown since the long term CAMD ARP CEMS data were used to determine the average performance of the best demonstrated technology. Those long term data were assumed to incorporate process variability including that associated with fuel and process/operational changes and periods of startup and shutdown.

However, the EPA notes that its work practice requirements provide flexibility to the operator to take appropriate site-specific remedial measures, if needed. The EPA further notes that boilers have several options to prevent detrimental impacts by: (1) Using startup fuels, natural gas or distillate oil, until appropriate flue gas conditions have been reached and then fire residual oil; (2) pre-coating the PM control surfaces[313] with an alkaline powder (*e.g.,* limestone); (3) installing chemically resistant bags[314] in baghouses if applicable; and (4) using low-sulfur oils. The EPA also notes that currently the industry has many operational residual oil-fired boilers that are started up with either natural gas or distillate fuel oil. At these boilers, the transition from the startup fuel, distillate oil or natural gas, to residual oil is already being practiced without unacceptable impacts on APCDs including PM controls, which are operated to meet applicable opacity limits. Based on this experience and the options described above, those boilers where residual oil is used for either a part of the startup period, or as the main fuel, will also be able to operate their PM controls to meet the work practice requirements of the rule. Note that coal firing is done at high enough temperatures that concerns with condensation are not relevant. None of the commenters have specifically commented on this aspect of coal firing.

The EPA is not aware of any operational constraints applicable to operation of wet scrubbers during startup that could cause detrimental impacts on wet scrubber hardware and safety concerns and none of the commenters have commented on this aspect of wet scrubber operation.

Finally, the EPA notes that dry sorbent injection (DSI) can be applied across a very broad temperature range and will be engaged when residual oil or coal is fired in a boiler to comply with HCl requirements. Again, no comments have been received on this aspect of DSI operation.

This final rule requires work practice standards for emissions during startup and shutdown, and the rule requires sources to measure and report their emissions at all times, including periods of startup and shutdown, when continuous monitoring is used to demonstrate compliance. Data collected under this final rule will provide the EPA with information to more fully analyze this issue and address it during the 8-year review established under CAA section 112.

We now address malfunctions. In contrast to the exclusion of startup and shutdown period emissions from 30-boiler operating day rolling average emissions, the final rule requires inclusion of emissions during periods of source or APCD malfunction. We have concluded that when combined with the availability of an affirmative defense as described below, this is an appropriate and practical approach.

As mentioned earlier, periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a ''sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *'' (40 CFR 63.2). The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards. Under CAA section 112, emissions standards for new sources must be no less stringent than the level ''achieved'' by the best controlled similar source and for existing sources generally must be no less stringent than the average emission limitation ''achieved'' by the best performing 12 percent of sources in the category. There is nothing in CAA section 112 that directs the Agency to consider malfunctions in determining the level ''achieved'' by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the CAA section 112 case law, nothing in that case law requires the Agency to consider malfunctions as part of that analysis. Clean Air Act section 112 uses the concept of ''best controlled'' and ''best performing'' unit in defining the level of stringency that CAA section 112 performance standards must meet. Applying the concept of ''best controlled'' or ''best performing'' to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not ''reasonably'' foreseeable. *See, e.g., Sierra Club* v. *EPA,* 167 F. 3d 658, 662 (D.C. Cir. 1999) (The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to ''invest the resources to conduct the perfect study.''). *See also, Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''). In addition, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with CAA section 112, and we believe it is a reasonable interpretation of the statute. This approach to malfunctions has been used consistently in CAA section 112 and CAA section 129 rulemaking actions since the D.C. Circuit's decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008) vacated the SSM exemption contained in CFR 63.6(f)(1) and 40 CFR 63.6(h)(1). (*See, e.g.,* National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants, 75 FR 54970 (September 9, 2010); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units; Final Rule, 76 FR 15372 (March 21, 2011).

In the event that a source fails to comply with the applicable CAA section 112(d) standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses

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[313] Coal Power, May 1, 2007: *http://www.coalpowermag.com/plant_design/Coal-Plant-O-and-M-River-Locks-and-Barges-Are-an-Aging-Workforce-Too 36.html.*

[314] Neundorfer: Lesson #r, p.4–7, Table 4–1: *http://www.neundorfer.com/FileUploads/CMSFiles/Fabric%20Filter%2OMaterial [0].pdf.*

to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 112(d) standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 63.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). The EPA is therefore adding to the final rule an affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions. *See* 40 CFR 63.10042 (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 63.10001. (*See* 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (*i.e.,* sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to assert the affirmative defense successfully, the source must prove by a preponderance of the evidence that excess emissions ''[w]ere caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.10001 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when the applicable emission limitations were being exceeded * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health * * *'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with CAA section 113 (*see* also 40 CFR 22.27).

The EPA is including an affirmative defense in the final rule as we have in other recent MACT rules so as to balance the tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. The EPA must establish emission standards that ''limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.'' 42 U.S.C. 7602(k) (defining ''emission limitation and emission standard''). *See* generally *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that section 112 emissions limitations are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission limitation is still enforceable through injunctive relief. While ''continuous'' limitations, on the one hand, are required, there is also case law indicating that in some situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 ''variant provisions'' such as provisions allowing for upsets during startup, shutdown and equipment malfunction ''appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force.'' *See* also, *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments calls into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for excess emissions that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating ''upsets beyond the control of the permit holder.'' *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). But *see, Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to ensure both that its emission limitations are ''continuous'' as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

F. Testing and Initial Compliance

We have carefully evaluated the wide-ranging comments on testing, continuous monitoring, and other provisions regarding initial compliance demonstrations, and we have made adjustments intended to help streamline implementation while still ensuring adequate demonstration of compliance with the emission limits and other standards established under this final rule. The significant changes include:

1. No Fuel Analysis Requirements

Apart from an alternative that allows you to analyze fuel moisture for liquid oil-fired EGUs rather than measuring HCl and HF, the final rule does not include any of the fuel analysis requirements that were in the proposed rule, either as part of initial compliance demonstrations or ongoing compliance demonstrations. In reviewing the results of the fuel analyses and the expected range of results that would be received from laboratories conducting the proposed analyses, we determined that too many results would be returned as ''below detection level'' and, thus, provide little information to assist with rule implementation and compliance oversight. Given the costs and efforts involved, we determined that the proposed fuel analysis requirements would not be an effective compliance monitoring tool for this final rule.

2. Clarification of Testing

We have clarified that where options for emission limits apply (such as filterable PM versus non-mercury HAP metals, or SO_2 versus HCl), you need only perform stack testing to demonstrate compliance with the selected emission limit. For example, if you elect to meet the individual non-mercury HAP metals standards, you must conduct the Method 29 test for the metals, and you do not have to conduct a Method 5 test for PM.

3. Low Emitting EGU Qualification

We have significantly modified the proposed requirements to qualify as a LEE unit for a pollutant other than Hg based on an initial performance test. Under the proposed rule, the operating limit monitoring provided additional assurance of compliance for a source qualified for non-mercury LEE status based on an initial compliance demonstration. Under the final rule, to qualify for LEE status for pollutants other than Hg, a unit must meet the LEE criteria for a series of performance tests over a 3-year period to demonstrate that the unit continues to perform well below the standard for which the source has obtained LEE status.

G. Continuous Compliance

The most significant changes to the testing and monitoring requirements involve the procedures for demonstrating continuous compliance. The proposed rule contained different options involving CEMS, periodic stack tests, fuel analysis, and various PM and control device operating limits. The final rule greatly simplifies the requirements and provides two basic approaches for most situations: use of continuous monitoring (either CEMS or PM continuous parametric monitoring system, CPMS) or periodic quarterly testing. The final rule does not contain the proposed fuel analysis requirements. For periodic testing, the proposed rule required testing every month or every 2 months. For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units. The rule requires quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards. The final rule also has a separate compliance demonstration for those liquid oil-fired EGUs that have an annual capacity factor of less than 8 percent (emission limits do not apply, just the tune-up work practice standard). For those EGU owners or operators who choose to use emissions testing to demonstrate compliance, the final rule requires quarterly filterable PM or non-mercury metals HAP, whether individual or total metals, testing for coal- and liquid oil-fired units; quarterly HCl testing for coal-fired units and quarterly HCl and HF testing, along with site-specific parameter monitoring for liquid oil-fired units to ensure compliance with the HCl and HF standards.

The continuous monitoring options remain generally intact from the proposed rule, with relatively minor clarifications concerning calculation of 30-boiler operating day averages and QA requirements.

The final rule eliminates all operating limits for PM except for the use of a PM CPMS. For the PM CPMS, the final rule clarifies procedures for setting this operating limit and how it is distinct from the PM emission limit. The PM CPMS will not be correlated as a PM CEMS under PS 11 and will produce data in terms of a signal you define. That signal could be milliamps, stack concentration, or other output signal instead of PM emissions in units of the standard. The operating limit will be set using the highest hourly average obtained from the PM CPMS during the performance test. Compliance with the limit is based on a 30-boiler operating day rolling average basis. However, the final rule also does provide for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. The EPA believes that some sources may be interested in adopting this direct approach, and so has included that option in the final rule. If this approach is selected, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of the QA requirements in PS 11 and Procedure 2. To use this option, the source must elect to meet the filterable PM standard, and not one of the HAP metals standards.

Apart from the operating limit for site-specific monitoring associated with liquid oil-fired EGUs, we removed the other operating limits for control devices based on a review of the comments, after considering other programs in place to ensure proper operations of controls at EGUs. Those other programs include compliance assurance monitoring under part 64, part 70, and New Source Review permit conditions, and other SIP and NSPS requirements for operating and maintaining equipment in accordance with good air pollution control practices. Those requirements, in combination with the CEMS, PM CPMS, and frequent periodic testing provisions under the final rule, will enhance the monitoring of continuous compliance with the requirements of this rule.

Because the EPA is concerned that there will be little or no monitoring in these underlying applicable requirements for acid gases at liquid oil-fired EGUs, the final rule requires a site-specific monitoring plan for those units in this subcategory that demonstrate compliance with the HCl and HF standards through quarterly performance tests. With the exception for limited-use liquid oil-fired EGUs and other monitoring options available (such as fuel moisture monitoring or HCl/HF CEMS), the EPA believes this provision will apply to few units. The owner or operator will submit the site-specific plan to identify appropriate parameters that ensure that the operations of the unit critical to meeting the HCl/HF emission limits remain consistent with conditions during performance testing. This will be approved similarly to an alternative monitoring request. The plan should include the parameters, monitoring approach, QA/QC elements, and data reduction (including averaging period) elements. Like the PM CPMS operating limit, the operating limit for acid gas control devices on liquid oil-fired EGUs will be set using the highest hourly average obtained during the HCl and HF performance tests. Compliance with the limit is based on a 30-boiler operating day rolling average basis.

Finally, we have changed the continuous compliance requirements for the performance tune-up work practice standard since the proposal. Our intent was that this work practice standard could be performed in conjunction with routine maintenance operations at a facility and be a logical extension of routine best practices for boiler inspection and optimization. Based on the comments received, we have reduced the required frequency for this inspection to every 3 years and provided incentives for neural network combustion management and optimization practices by providing a longer interval of 4 years between inspections when such systems are in use at a given EGU.

H. Emissions Averaging

We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for existing EGUs that are located at the same facility that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

As we noted at proposal, part of the EPA's general policy of encouraging the use of flexible compliance approaches where they can be properly monitored and enforced is to include emissions averaging. Emissions averaging can provide sources the flexibility to comply in the least costly manner while still maintaining a regulation that is workable and enforceable. Emissions averaging would not be applicable to new affected sources and could only be used between EGUs in the same subcategory at a particular facility. Also, owners or operators of existing sources subject to the EGU NSPS (40 CFR part 60, subparts D and Da) would be required to continue to meet the PM emission standard of that NSPS regardless of whether or not they are using emissions averaging (*i.e.,* an EGU subject to 40 CFR part 60, subpart D or Da must meet its applicable NSPS filterable PM emission limit even if it is included in a 40 CFR part 63, subpart UUUUU, emissions averaging group for filterable PM).

Emissions averaging allows owners and operators of a facility that includes existing EGUs within a subcategory to demonstrate that the source complies with the proposed emission limits by averaging the emissions from an individual affected EGU that is emitting above the proposed emission limits with other affected EGUs at the same facility that are emitting below the proposed emission limits and that are within the same subcategory. Although some commenters note that the MACT limits are low, based on the data available to the Agency, we believe that dozens of existing EGUs are achieving all of the limits and, thus, emissions averaging is a possible approach.

The final rule includes an emissions averaging compliance alternative because emissions averaging[315] represents an equivalent, more flexible, and less costly alternative to controlling certain emission points to MACT levels. We have concluded that averaging in the proposed rule could be implemented and that it would not lessen the stringency of the MACT floor limits and would provide flexibility in compliance, cost and energy savings to owners and operators. We also recognize that we must ensure that any emissions averaging option can be implemented and enforced, will be clear to sources, and most importantly, will be no less stringent than unit-by-unit implementation of the MACT floor limits.

In the final rule, the EPA is providing that sources may average emissions from existing EGUs at the same facility and within the same subcategory. Further, for Hg emissions only from existing EGUs within the same subcategory, such EGUs in an emissions averaging plan may use an alternate compliance approach consisting of a 90-boiler operating day rolling average emission limit of 1.0 lb/TBtu or 1.1E–2 lb/GWh.

In the memo entitled ''The Impact of Emission Averaging Time on the Stringency of an Emission Standard'' in the docket, we have illustrated why a longer-term average results in a lower limit. In essence, longer-term averages allow particularly high (or low) measurements to be averaged with many more measurements closer to the mean. This results in the highest averages from a longer-term averaging period (*e.g.,* 90 days) being lower than the highest averages in a shorter term averaging period (*e.g.,* 30 days).

We have illustrated this concept by taking Hg CEMS data and calculating rolling 30-day averages and rolling 90-day averages. The 30-day averages have greater variability and, thus, higher peaks and valleys. The 90-day average has less variability; therefore, the same unit is able to meet a tighter 90-day limit.

The EPA is providing this alternate 90-day rolling average compliance approach for Hg only. A 90-day rolling average is appropriate for Hg, and only for Hg, because the health and environmental impacts associated with Hg are related to environmental loading rather than shorter term inhalation or other acute exposure, as is the case with HCl and PM. We believe that this alternative compliance approach will provide at least the same level of environmental protection while allowing companies greater flexibility to use emissions averaging. For example, such an approach would allow for the averaging of an infrequently operated unit that is operating slightly above the standard with a more frequently operated unit that is operating below the standard in the instances when the more frequently operated unit is in a multi-day or multi-week maintenance outage.

The EPA has concluded that it is permissible to establish within a NESHAP a unified compliance regimen that permits averaging within the same facility across individual existing EGUs subject to the same standards under certain conditions. As mentioned earlier, individual EGUs within an emissions averaging group would be allowed to have emissions greater than, less than, or equivalent with the emissions limit for their subcategory, provided that the average emissions comprised from individual EGU emissions do not exceed the emissions limit for their subcategory. Averaging across affected units is permitted only if it can be demonstrated that the total quantity of any particular HAP that may be emitted by that portion of a contiguous major source that is subject to the same standards in the NESHAP will not be greater under the averaging mechanism than it could be if each individual affected EGU in the subcategory complied separately with the applicable standard. Under this test, the practical outcome of averaging is equivalent to compliance with the MACT floor limits by each discrete EGU, and the statutory requirement that the MACT standard reflect the maximum achievable emissions reductions is, therefore, fully effectuated.

As noted in the proposal preamble, in past rulemakings, the EPA has generally imposed certain limits on the scope and nature of emissions averaging programs. These limits include: (1) No averaging between different types of pollutants; (2) No averaging between sources that are not part of the same affected source; (3) No averaging between individual sources within a single major source if the individual sources are not subject to the same NESHAP; and (4) No averaging between existing sources and new sources.

The final rule fully satisfies each of these criteria. First, emissions averaging would only be permitted between individual existing sources at a single stationary source (*i.e.,* the facility), and would only be permitted between individual sources in the same subcategory in the final EGU NESHAP. Further, emissions averaging would not be permitted between two or more different affected sources. Finally, new affected sources could not use emissions averaging. Accordingly, we have concluded that the averaging of emissions across affected units in the same existing source subcategory is consistent with the CAA. In addition, the final rule requires each facility that intends to utilize emissions averaging to develop an emissions averaging plan, which provides additional assurance that the necessary criteria will be followed. In this emissions averaging plan, the facility must include the identification of: (1) All units in the averaging group; (2) the control technology installed; (3) the process parameter that will be monitored; (4) the specific control technology or pollution

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[315] As long as required emission rates are designed to account for factors such as changes in averaging times.

prevention measure to be used; (5) the test plan for the measurement of the HAP being averaged; and (6) the operating parameters to be monitored for each control device. A state, local, or tribal regulatory agency that is delegated authority for this rule could require the emissions averaging plan to be submitted or even approved before emissions averaging could be used. Upon receipt, the regulatory authority would not be able to approve an emissions averaging plan differing from the eligibility criteria contained in the rule.

The final rule excludes new affected sources from the emissions averaging provision. The EPA does not believe the statute authorizes emissions averaging for new affected sources. One reason we allow emissions averaging is to give existing sources flexibility to achieve compliance at diverse points with varying degrees of add-on control already in place in the most cost-effective and technically reasonable fashion.

With the monitoring and compliance provisions that are being finalized, there is additional assurance that the environmental benefit will be realized. Further, the emissions averaging provision would not apply to individual EGUs if the EGU shares a common stack with units in other subcategories, because in that circumstance it is not possible to distinguish the emissions from each individual unit.[316]

The rule allows EGUs that rely on CEMS for compliance demonstrations to be able to participate in emissions averaging and the emissions limits are not subject to a discount. The EPA believes that the data certainty provided by units that use CEMS would be ideal for emissions averaging and the flexibility and cost-effectiveness it offers. Given the homogeneity of fuels within the rules subcategories, along with other emissions averaging criteria, the Agency believes use of a discount factor to be unwarranted for this rule.

The emissions averaging provisions in this final rule are based in part on the emissions averaging provisions in the Hazardous Organic NESHAP (HON). The legal basis and rationale for the HON emissions averaging provisions were provided in the preamble to the final HON.[317] We do not believe that we have the authority to provide for emissions averaging among EGUs in different subcategories or among EGUs not physically located at the same affected facility.

I. Notification, Recordkeeping, and Reporting

Compared to the proposed rule, the reduced continuous compliance requirements in the final rule—primarily reduced testing frequencies and removal of fuel analyses and control device or fuel operating parameter monitoring—considerably reduces the overall burden associated with recordkeeping and reporting. Based on evaluation of the comments received, we have established a provision in the final rule for submission of most CEMS data (including monitoring plan, emissions data, and QA data) through ECMPS, so that the affected industry uses a common reporting tool for submitting CEMS data.

For data other than most CEMS data, the final rule requires electronic reporting of certain data, including performance test reports, PM CPMS data, PM CEMS data, and, if approved as part of an alternative monitoring request, HAP metals CEMS data. Other reports, such as notifications, must be submitted in hard copy format or in accordance with the procedures established by state and local agencies that receive delegation for implementing this rule. In the proposed rule, we took comment on these approaches and stated our anticipation of adopting these approaches. In the final rule, we have extended the ECMPS reporting to most CEMS data to promote harmonization for CEMS data from the industry, while leaving reporting of non-CEMS data in a separate reporting system.

J. Technical/Editorial Corrections

In this final action, we are making a number of technical corrections and clarifications to 40 CFR part 63, subpart UUUUU. These changes clarify procedures for implementing the emission limitations for affected sources. We are also clarifying several definitions to help affected sources determine applicability of this rule. We have modified some proposed regulatory language based on public comments. In addition, in response to comments received (including the May 2010 notice from the Utility Air Regulatory Group (UARG) of calculation errors in the proposed Hg MACT floor limits), we have checked all calculations and made corrections where necessary.

In several places throughout the subpart, including the associated tables, we have corrected the cross-references to other sections and paragraphs of the subpart.

VII. Public Comments and Responses to the Proposed NESHAP

A. MACT Floor Analysis

1. New Data/Technical Corrections to Old Data

Comment: Many commenters identified errors in the emissions database compiled through information provided by industry in response to the 2010 information collection request (ICR) that supported development of this rule. Commenters submitted corrections to the EPA during the public comment period.

Response: The EPA has incorporated technical corrections and new data submitted prior to the end of the comment period. The corrections and new data are described in detail in a memorandum in the docket. The EPA re-ranked the sources in the MACT floor pools to the extent necessary based on the new or corrected data, and we recalculated the MACT floors as necessary based on the re-ranking of sources. The revised MACT floors were established using the same methodology set forth in the proposed rule.

2. Pollutant-by-Pollutant Approach

Comment: Many commenters raised concerns about the way the EPA determined the MACT floors using a pollutant-by-pollutant approach. Commenters contended that such a methodology produced limits that are not achievable in combination, and as such, the limits do not comport with the intent of the statute or the recent court decision (*NRDC* v. *EPA,* 2007). Commenters further added that the CAA directs the EPA to set standards based on the overall performance of ''sources'' and CAA sections 112(d)(1), (2), and (3) specify that emissions standards be established on the ''in practice'' performance of a ''source'' in the category or subcategory. Commenters stated that if Congress had intended for the EPA to establish MACT floor levels considering the achievable emission limits of individual HAP, it could have worded CAA section 112(d)(3) to refer to the best-performing sources ''for each pollutant.'' Many commenters added that the EPA's discretion in setting standards is limited to distinguishing among classes, types, and sizes of sources. Commenters contend that although Congress limited the EPA's authority to parse units and sources with similar design and types, it does not allow the EPA to ''distinguish'' units and sources by individual pollutant as proposed in this rule (*Sierra Club* v. *EPA,* 551 F.3d 1019, 1028 (D.C. Cir. 2008)). By calculating each MACT floor

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[316] The EPA has reviewed monitoring data submitted to the Agency under the Title IV Acid Rain Program. Based on that review, the EPA is unaware of any coal- and oil-fired units that share a common stack.

[317] Hazardous Organic NESHAP (59 FR 19,425; April 22, 1994).

independently of the other pollutants, commenters contend that the combination of HAP limits results in a set of standards that only a hypothetical ''best performing'' unit could achieve.

Response: We disagree with the commenters who believe MACT floors cannot be set on a pollutant-by pollutant basis. Contrary to the commenters' suggestion, CAA section 112(d)(3) does not mandate a total facility approach. A reasonable interpretation of CAA section 112(d)(3) is that MACT floors may be established on a HAP-by-HAP basis, so that there can be different pools of best performers for each HAP. Indeed, as illustrated below, the total facility approach not only is not compelled by the statutory language but can lead to results so arbitrary that the approach may simply not be legally permissible.

Clean Air Act section 112(d)(3) is not explicit as to whether the MACT floor is to be based on the performance of an entire source or on the performance achieved in controlling particular HAP. Congress specified in CAA section 112(d)(3) the minimum level of emission reduction that could satisfy the requirement to adopt MACT. For new sources, this floor level is to be ''the emission control that is achieved in practice by the best controlled similar source.'' For existing sources, the floor level is to be ''the average emission limitation achieved by the best performing 12 percent of the existing sources'' for categories and subcategories with 30 or more sources, or ''the average emission limitation achieved by the best performing 5 sources'' for categories and subcategories with fewer than 30 sources. Commenters point to the statute's reference to the best performing ''sources,'' and claim that Congress would have specifically referred to the best performing sources ''for each pollutant'' if it intended for the EPA to establish MACT floors separately for each HAP.

The EPA disagrees. The language of the Act does not address whether floor levels can be established HAP-by-HAP or by any other means. The reference to ''sources'' does not lead to the assumption the commenters make that the best performing sources can only be the best-performing sources for the entire suite of regulated HAP. Instead, the language can be reasonably interpreted as referring to the source as a whole or to performance as to a particular HAP. Similarly, the reference in the new source MACT floor provision to ''emission control achieved by the best controlled similar source'' can mean emission control as to a particular HAP or emission control achieved by a source as a whole.

Commenters also stressed that CAA section 112(d) requires that floors be based on actual performance from real facilities. The EPA agrees that this language refers to sources' actual operation, but again the language says nothing about whether it is referring to performance as to individual HAP or to single facility's performance for all HAP. Industry commenters also said that Congress could have mandated a HAP-by-HAP result by using the phrase ''for each HAP'' at appropriate points in CAA section 112(d). The fact that Congress did not do so does not compel any inference that Congress was *sub-silentio* mandating a different result when it left the provision ambiguous on this issue. The argument that MACT floors set HAP-by-HAP are based on the performance of a hypothetical facility, so that the limitations are not based on those achieved in practice, just reiterates the question of whether CAA section 112(d)(3) refers to whole facilities or individual HAP. All of the limitations in the floors in this rule reflect sources' actual performance and were achieved in practice. As to commenters' claims that standards set in this manner cannot be met by any actual sources, we have determined that there are approximately 69 existing coal-fired EGUs that meet all of the final existing source MACT emission limits (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR) and at least one EGU that meets all of the final new source MACT emission limits.

Commenters also point to the EPA's subcategorization authority, and claim that because Congress authorized the EPA to distinguish among classes, types, and sizes of units, the EPA cannot distinguish units by individual pollutant, as they allege the EPA did in the proposed rule. However, that statutory language addresses the EPA's authority to subcategorize sources within a source category prior to setting standards, which the EPA has done for certain EGUs. The EPA is not distinguishing within each subcategory based on HAP emitted. Rather, it is establishing emissions standards based on the emissions limits achieved by units in each subcategory. Therefore, the EPA's subcategorization authority is irrelevant to the question of how the EPA establishes MACT floor standards once it has made the decision to distinguish among sources and create subcategories.

The EPA's long-standing interpretation of the Act is that the existing and new source MACT floors are to be established on a HAP-by-HAP basis. One reason for this interpretation is that a whole plant approach could yield least common denominator floors—that is, floors reflecting limited or no control, rather than performance which is the average of what best performers have achieved. *See* 61 FR 173687 (April 19, 1996); 62 FR 48363–64 (September 15, 1997) (same approach adopted under the very similar language of CAA section 129(a)(2)). Such an approach would allow the performance of sources that are outside of the best-performing 12 percent for certain pollutants to be included in the floor calculations for those same pollutants, and it is even conceivable that the worst performing source for a pollutant could be considered a best performer overall, a result Congress could not have intended. Inclusion of units that are outside of the best performing 12 percent for particular pollutants would lead to emission limits that do not meet the requirements of the statute.

For example, if the best performing 12 percent of facilities for HAP metals were also the worst performing units for acid gas HAP and the best performers for acid gas HAP were the worst performers for HAP metals, the floor for acid gases or metals would end up not reflecting best performance. In such a situation, the EPA would have to make a value judgment as to which pollutant reductions were most critical to decide which sources are best controlled.[318] Such value judgments are antithetical to the direction of the statute at the MACT floor-setting stage.

Commenters suggested that a multi-pollutant approach could be implemented by weighting pollutants according to relative toxicity and calculating weighted emissions totals to use as a basis for identifying and ranking best performers. This suggested approach would require the EPA to essentially prioritize the regulated HAP based on relative risk to human health of each pollutant, where risk is a criterion that has no place in the establishment of MACT floors, which are required by statute to be based on technology.

The central purpose of the amended air toxics provisions was to apply strict technology-based emission controls on HAP. *See, e.g.,* H. Rep. No. 952, 101st Cong. 2d sess. 338. An interpretation that the floor level of control must be limited by the performance of devices

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[318] See Petitioners Brief in *Medical Waste Institute et al.* v. *EPA,* No. 09–1297 (D.C. Cir.) pointing out, in this context, that ''the best performers for some pollutants are the worst performers for others'' (p. 34) and ''[s]ome of the best performers for certain pollutants are among the worst performers for others.''

that only control some of these pollutants effectively guts the standards by including worse performers in the averaging process, whereas the EPA's interpretation promotes the evident Congressional objective of having the floor reflect the average performance of best performing sources. Because Congress has not spoken to the precise question at issue, and the Agency's interpretation effectuates statutory goals and policies in a reasonable manner, its interpretation must be upheld. *See Chevron* v. *NRDC,* 467 U.S. 837 (1984).[319]

The EPA notes, however, that if optimized performance for different HAP is not technologically possible due to mutually inconsistent control technologies (for example, if metals performance decreased as organics reduction is optimized), then this would have to be taken into account by the EPA in establishing a floor (or floors). The Senate Report indicates that if certain types of otherwise needed controls are mutually exclusive, the EPA is to optimize the part of the standard providing the most environmental protection. S. Rep. No. 228, 101st Cong. 1st sess. 168 (although, as noted, the bill accompanying this Report contained no floor provisions). It should be emphasized, however, that the D.C. Circuit has stated that ''the fact that no plant has been shown to be able to meet all of the limitations does not demonstrate that all the limitations are not achievable.'' *Chemical Manufacturers Association* v. *EPA,* 885 F. 2d at 264 (upholding technology-based standards based on best performance for each pollutant by different plants, where at least one plant met each of the limitations but no single plant met all of them).

All available data for EGUs indicate that there is no technical problem achieving the floor levels contained in this final rule for each HAP simultaneously, using the MACT floor technology. Data demonstrating a technical conflict in meeting all of the limits have not been provided, and, as stated above, based on the available data, there are approximately 64 EGUs that meet all of the final existing source emission limits and at least one EGU that meets all of the final new source emission limits.

3. Minimum Number of EGUs To Set Floors

Comment: Many commenters indicated that CAA section 112 requires that data from a minimum of 5 units are required to set MACT floors for existing sources. Commenters noted that the EPA's use of less than 5 units for subcategories with greater than 30 units is a legalistic reading of CAA section 112 that could result in such absurd results as using 5 units to set MACT floors for a subcategory with 29 units and data for only 10 units, but using a single unit to set MACT floors for a subcategory with 31 units and data for only 10 units.

Response: The EPA does not agree that CAA section 112(d)(3) mandates a minimum of 5 sources in all instances, notwithstanding the incongruity of having less data to establish floors for larger source categories than is mandated for smaller ones. The literal language of the provision appears to compel this result. CAA section 112(d)(3) states that for categories and subcategories with at least 30 sources, the MACT floor for existing sources shall be no less stringent than the average emission limitation achieved by the best-performing 12 percent of the sources for which the Administrator has emissions information. The plain language of this provision requires the use of fewer data points for large source categories than for small source categories where the Administrator only has emissions information on a small number of units for categories and subcategories with 30 or more sources. Furthermore, commenters contend that Congress could not have intended the floors for a subcategory with 29 sources to be based on 5 sources and a subcategory with 31 sources to be based on less than that number; but we maintain this contention is without merit because 12 percent of 31 is 3.72 (rounded to 4) so the EPA would not base standards for a subcategory with 31 sources on 5 sources even if we had data on all 31 sources in the subcategory. For these reasons, we decline to adopt commenters' position and continue to adhere to the clear statutory directive.

4. Treatment of Detection Levels

Comment: Commenters stated that when setting the MACT floors, non-detect values are present in many of the datasets from best performing units. Commenters provided input on how these non-detect values should be treated in the MACT floor analysis. Some commenters agreed that it is appropriate to keep the detection levels as reported, while certain commenters suggested that the detection levels should be replaced using a value of half the method detection limit (MDL). Many other commenters stated that data that are below the detection limit should not be used in setting the floors, and these data should be replaced with a higher value including either the MDL, limit of quantitation (LOQ), practical quantitation limit (PQL), or reporting limit (RL) for the purposes of the MACT floor calculations. Other commenters stated all non-detect values should be excluded from the floor analysis, or all values should be treated as zero.

Some commenters stated it is necessary to keep the data as reported because changing values would lead to an upward bias. Additional commenters agreed with this basic premise, but suggested that replacing non-detect data with a value of half the MDL is appropriate while still minimizing the bias. They noted that treating measurements below the MDL as occurring at the MDL is statistically incorrect and violates the statute's ''shall not be less stringent than'' requirement for MACT floors. One commenter also provided a reference for a statistical method based on a log-normal distribution of the data which estimated the ''maximum likelihood'' of data values; this result is slightly higher than half the MDL.

Some commenters stated that it is necessary to substitute the MDL value when performing the MACT floor calculations. With MDL defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance, this is an appropriate value. If MDL values are not reported, one commenter suggested an approach for estimating an MDL equivalent value, but recognized that the background laboratory and test report files may not be available to the EPA in order to derive these estimates.

Most commenters representing industry and industry trade groups argued that either LOQ or PQL values should replace non-detects. The LOQ is defined as the smallest concentration of the analyte which can be measured. These commenters contended that the LOQ leads to a quantifiable amount of the substance with an acceptable level of uncertainty. A few commenters provided calculations showing some of the proposed MACT floors were below the LOQ. Additionally, some of these commenters stated that using LOQ or PQL values also incorporates additional sources of random and inherent sampling error throughout the testing process, which is necessary. These errors occur during sample collection, sample recovery, and sample analysis;

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[319] Because industry commenters argued that the statute can only be read to allow floors to be determined on a single source basis, commenters offered no view of why their reading could be viewed as reasonable in light of the statute's goals and objectives. It is not evident how any statutory goal is promoted by an interpretation that allows floors to be determined in a manner likely to result in floors reflecting emissions from worst or mediocre performers.

MDL values only account for method specific (*e.g.,* instrument) errors. These commenters contended that the three times the MDL approach discussed in the proposal accounts for some measurement errors but does not account for these unavoidable sampling errors. The commenters also noted that an LOQ is calculated as 3.18 times the MDL, and PQL is calculated as 5 to 10 times the MDL. Many of the commenters in support of using either an LOQ or PQL value ultimately believed a work practice is more appropriate where a MACT floor limit is below either of these two values. They cited CAA section 112(h)(1) which allows work practices under CAA section 112(h)(2) if ''the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations''. These commenters stated that the inability of sources to accurately measure a pollutant at the level of the MACT floor qualifies as such a technological limitation that warrants a work practice standard.

Commenters stated that where the proposed MACT floor is below the LOQ or PQL then that source category has a technological measurement limitation. A few commenters suggested RL values should be used when developing the floor limits. They stated that the RL is the lowest level at which the entire analytical system gives reliable signals and includes an acceptable calibration point. They added that use of an acceptable calibration point is critical in showing that numbers are real versus multiplying the MDL by various factors.

Several commenters stated that all non-detect values should be excluded from MACT floor calculations. They believed that excluding all non-detect values would eliminate any potential errors or accuracy issues related to testing for compliance. Due to inconsistencies of the MDL value reported for non-detect data, one commenter suggested treating all such values as zero. This would provide a consistent approach for setting the floor as well as determining compliance.

Several commenters provided input on the EPA's proposed method of three times the MDL as an option for setting limits. A few commenters in support noted that this approach provided a reasonable method to account for data variability as it took into account more than just analytical instrument precision. Many other commenters argued that this method results in limits which are too low, namely that it is still lower than the LOQ value which they are in favor of as a substitute for any reported non-detect data. Other commenters disagreed with this method and claimed that it would lead to results which introduce a high bias in the floor setting process. A few contended that multiplying by 3 would introduce a 300 percent error into the floor, resulting in a floor that is less stringent than required by the Act. Others suggested that the MDL values are antiquated and already too high and thus it is not appropriate to multiply them by three. Also, a few commenters suggested multiplying the MDL by three would not reflect the actual lower emissions achieved by any source and as such is unlawful under CAA section 112(d).

Response: We agree with many of the comments related to treatment of data reported as detection limit values in the development of MACT floors and emissions limits. As we noted at proposal, the statistical probability procedures applied in calculating the floor or an emissions limit inherently and reasonably account for emissions data variability including measurement imprecision when the database represents multiple tests from multiple emissions units for which all of the data are measured significantly above the method detection level. That is less true when the database includes emissions occurring below method detection capabilities regardless of how those data are reported.

The EPA's guidance to respondents for reporting pollutant emissions used to support the data collection specified the criteria for determining test-specific method detection levels. Those criteria ensure that there is only about a 1 percent probability of an error in deciding that the pollutant measured at the method detection level is present when in fact it was absent. (Reference: ReMAP: PHASE 1, Precision of Manual Stack Emission Measurements; American Society of Mechanical Engineers, Research Committee on Industrial and Municipal Waste, February 2001.) Such a probability is also called a false positive or the alpha, Type I, error. This means specifically that for a normally distributed set of measurement data, 99 out of 100 single measurements will fall within $\pm 2.54 \times$ standard deviation of the true concentration. The anticipated range for the average of repeated measurements comes progressively closer to the true concentration. More precisely, the anticipated range varies inversely with the square root of the number of measurements. Thus, for a known standard deviation (SD) of anticipated single measurements, the anticipated range for 99 out of 100 future triplicate measurements will fall within ± 2.54 SD/$\sqrt{3}$ of the true concentration. This relationship translates to an expected measurement imprecision for an emissions value occurring at or near the method detection level of about 40 to 50 percent.

By assuming a similar distribution of measurements across a range of values and increasing the mean value to a representative higher value (*e.g.,* 3 times minimum detection level or 3xMDL), we can estimate measurement imprecision at other levels. For an assumed 3xMDL, the estimated measurement imprecision for a three test run average value would be on the order 10 to 20 percent. This is about the same measurement imprecision as found for Methods 23 and 29 indicated in the ASME ReMAP study for the sample volumes prescribed in the final rule (*e.g.,* 4 to 6 dscm) for multiple tests.

Analytical laboratories often report a value above the method detection limit that represents the laboratory's perceived confidence in the quality of the value. This independently adjusted value is expressed differently by various laboratories and is called LOQ, PQL, or RL. In many cases, the LOQ, PQL, or RL is simply a multiplication of the method detection limit. Commonly used multipliers range from 3 to 10. Because these values reflect individual laboratories' perceived confidence, and, therefore, could be viewed as arbitrary, we decline to adopt the LOQ, PQL, or RL because such approaches in our view would inappropriately inflate the MACT floor standards. Our alternative to those inconsistent approaches is discussed below.

Consistent with findings expressed in reports of emissions measurement imprecision and the practices of analytical laboratories, we believe that using a measurement value of 3 times a representative method detection limit established in a manner that assures 99 percent confidence of a measurement above zero will produce a representative method reporting limit suitable for establishing regulatory floor values.

On the other hand, we also agree with commenters that an emissions limit set from a small subset of data or data from a single source may be significantly different than the actual method detection levels achieved by the best performing units in practice. This fact, combined with the low levels of emissions measured from many of the best performing units, led the EPA since proposal to review and revise the procedure intended to account for the contribution of measurement imprecision to data variability in establishing effective emissions limits. In response to the comments about the quality of measurements at very low emissions limits especially for new sources, we revised the procedure for identifying a representative method detection level (RDL).

The revised procedure for determining an RDL starts with identifying all of the available reported pollutant-specific method detection levels for the best performing units regardless of any subcategory (*e.g.,* existing or new, fuel type, etc.). From that combined pool of data, we calculate the arithmetic mean value. By limiting the data set to those tests used to establish the floor or emissions limit (*i.e.,* best performers), which in this case is a larger data set than normally available for establishing NESHAP, we believe that the result is representative of the best performing testing companies and laboratories using the most sensitive analytical procedures. We believe that the outcome should minimize the effect of a test(s) with an inordinately high method detection level (*e.g.,* the sample volume was too small, the laboratory technique was insufficiently sensitive, or the procedure for determining the minimum value for reporting was other than the detection level). We then call the resulting mean of the method detection levels the representative detection level (RDL) because it is characteristic of accepted source emissions measurement performance.

The second step in the process is to calculate 3xRDL to compare with the calculated floor or emissions limit. This step is similar to what we have used for other NESHAP including the Portland Cement rule. As outlined above, we use the multiplication factor of 3 to reduce the imprecision of the analytical method until the imprecision in the field sampling reflects the relative method precision as estimated by the ASME ReMAP study. That study indicates that such relative imprecision remains a constant 10 to 20 percent over the range of the method. For assessing the calculated floor results relative to measurement method capabilities, if 3xRDL were less than the calculated floor or emissions limit (*e.g.,* calculated from the upper predictive limit, UPL), we would conclude that measurement variability was adequately addressed with the initial floor calculation. The calculated floor or emissions limit would need no adjustment. If, on the other hand, the value equal to 3xRDL were greater than the UPL, we would conclude that the calculated floor or emissions limit did not account entirely for measurement variability. Where such was the case, we substituted the value equal to 3xRDL for the calculated floor or emissions limit (UPL) which results in a concentration where the method would produce measurement accuracy on the order of 10 to 20 percent similar to other EPA test methods and the results found in the ASME ReMAP study.

We determined the RDL for each pollutant using data from tests of all the best performers for all of the final regulatory subcategories (*i.e.,* pooled test data). We applied the same pollutant-specific RDL and emissions limit assessment and adjustment procedures to all subcategories for which we established emissions limits. We believe that adjusting emissions limits in this manner, which ensures that measurement variability is adequately addressed relative to compliance determinations, is a better procedure than the one applied at proposal, which was based on more limited data. We also believe that currently available emissions testing procedures and technologies provide the measurement certainty sufficient for sources to demonstrate compliance at the levels of the revised emissions limits.

5. Basis for New Source MACT

Comment: Several commenters stated that the proposed limits set for new EGUs do not represent the best performing EGU. The commenters state that the EPA has chosen the strictest limit irrespective of the EGU and that limits for new EGUs should be achievable. According to the commenters, no existing EGU is currently meeting the proposed limits, which will result in a moratorium on the construction of new coal-fired EGUs. Further, commenters state that another result of the EPA's flawed approach is that the proposed standards for new EGUs are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters assert that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure which will, in turn, effectively preclude the construction of any new coal-based EGUs.

Commenters also stated that the EPA failed to address cumulative effects of using multiple pollution control devices in determining MACT levels applicable to PM levels. In proposing total PM as a surrogate, commenters believe that the EPA failed to consider or address the antagonistic effects that adding multiple pollution control devices can have on an EGU's HAP emissions. Commenters indicated that EGUs would not be able to comply with the proposed new source HCl limit without adding a scrubber or some type of sorbent injection to control HCl emissions. Adding these HCl control technologies will increase the total PM emissions of these units. According to commenters, because a fabric filter-alone configuration (the basis for the new source PM limit) would not meet all MACT limits, these units may not be the best-performing units.

Response: The EPA disagrees with the commenters' statements that no existing unit is currently meeting the new source limits. The EPA established the new source limits based on data from existing EGUs and there is at least one EGU, based on the data available, that is meeting all three final HAP limits and at least eight EGUs that are meeting one or more of the new source limits. As a result of comments received on the full body of data, the EPA has re-ranked the best performing EGUs and reviewed the new source limits based on the re-ranking where appropriate. Based on the revised ranking, the best performing source for PM has changed and that source now forms the basis for the new source filterable PM limit in the final rule. The source is a coal-fired EGU that includes the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively (*i.e.,* it is a unit with SCR, dry FGD, and FF). Thus, the commenters' concerns are no longer relevant as they relate to PM emissions from coal-fired EGUs.

The EPA also believes that the EGUs serving as the basis for the new source Hg and HCl limits in the final rule are representative of what a new coal-fired EGU would look like to meet all of the requisite regulations applicable to EGUs (*e.g.,* NSPS and the CSAPR) as they also include the entire suite of controls that would likely be required on a new coal-fired source constructed prospectively. The EPA has also taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the EGUs in the top performing 12 percent in establishing the final limits, and we have determined that there are adequate test methods to measure the regulated HAP at the new source levels.

6. Achievability of Limits

Comment: A number of commenters state that the EPA has chosen the strictest limit irrespective of the unit and that limits for new EGUs should be achievable. According to the commenters, no existing unit is currently meeting the proposed new source limits, which will result in a moratorium on the construction of new coal-fired units. The commenters state that this regulation goes beyond protecting public health and will impact the country's choice of fuel for energy production. Other commenters state that another result of the EPA's flawed approach is that the proposed standards for new units are so low that adequate test methodologies to demonstrate compliance do not exist. Without accurate testing methodologies, commenters allege that contractors will not guarantee that potential emission control technologies will meet the proposed standards. Without accurate test methodologies and vendor guarantees, commenters believe that financing of new facilities will be virtually impossible to secure, and that this in turn will effectively preclude the construction of any new coal-based units. Commenters maintain that adopting standards effectively banning new coal units amounts to a momentous change in national energy policy without discussion or analysis and far exceeds the EPA's authority.

Some commenters add that the proposed new source MACT standards do not represent rates that have been achieved in practice and are orders of magnitude lower than any of the CAA section 112(g) case-by-case MACT limits established for the most advanced units in the U.S. coal fleet by multiple state agencies.

Other commenters stated that the synergistic impact of multiple controls has not been taken into account in the proposed rules. Commenters argue that circumstances exist with respect to the control of acid gases, which will require scrubbers or other SO_2 controls that add particulate to the flue gas stream, and that added particulate must be removed by PM control devices along with the particulate added to the flue gas for EGUs that need to install ACI for Hg control. Because particulate devices provide a fixed percent reduction of particulate, commenters assert that it is mathematically certain that PM performance will decrease because control of both acid gases and Hg would add PM to the flue gas stream which would in turn decrease performance of the PM control on the relevant mass metric. As a consequence, commenters allege that there is no assurance that sources can meet the EPA's ''cherry-picked'' floors for acid gases and for Hg by ''optimizing'' these systems to meet the performance of the floor units because to do so would impact their ability to meet the EPA's similarly ''cherry-picked'' total PM floor standard.

The commenters state that, for existing sources as with the new source standard-setting approach, a pollutant-by-pollutant approach does not consider what the top performing 12 percent achieve in practice for all pollutants and does not consider the antagonistic effects of the concurrent use of various control technologies. For example, one commenter states that 47 of the 131 sources used to calculate the existing source total PM limit only had PM control but no acid gas or Hg controls that could emit additional PM. According to the commenter, the CAA is clear that standards must be based on actual sources and not the product of a pollutant-by-pollutant determination resulting in a set of composite standards that do not necessarily reflect the overall performance of any actual source. To address these issues, the commenter recommends that the EPA use an approach that more accurately reflects what actual best performing sources achieve.

Response: The EPA disagrees with the commenters' contention that the pollutant-by-pollutant approach to establishing MACT floors is inconsistent with the CAA for the reasons set forth in the response to comments on the EPA's MACT floor setting process. In addition, the EPA established the proposed new source limits based on data from existing EGUs, and there are EGUs that are able to meet the new source limits. To the extent the commenters are concerned that no existing source is simultaneously meeting all of the new sources limits, we note that the EPA has revised the new source standards based on comments and data corrections that industry made to data it incorrectly provided in response to the utility ICR. We have identified at least one source that is meeting all of the new source MACT limits in the final rule.

We disagree with commenters that suggest the proposed new source standards are invalid because they are more stringent than CAA section 112(g) case-by-case MACT limits established by state agencies. As commenters note, states, not the EPA, established the CAA section 112(g) standards, and they did so based on the information available to them. The EPA likewise must establish CAA section 112(d) standards based on the available data. We have considered the available data and information, including the 2010 ICR data, and complied with the requirements of CAA section 112(d) in establishing the standards in this final rule. That the final standards are more stringent than CAA section 112(g) standards issued by certain state agencies has no bearing on the legitimacy of the standards at issue here.

The EPA agrees with commenters that the SO_2 and some Hg controls may add to the PM loading and that it is reasonable to establish the new source standard based on an EGU that has a suite of controls that will be required of any new source. For example, new coal-fired EGUs will be required to comply with the utility NSPS and may have to comply with the CSAPR and other requirements (*e.g.,* SIP or state-only requirements). Commenters are also correct that the proposed new source PM surrogate standard was based on a source that is not like a coal-fired EGU that would be constructed today (*i.e.,* an EGU with only PM control and no SO_2 controls).

The final standard is not based on the source used to establish the proposed limit. As stated above, industry commenters provided data corrections and new data and the EPA considered that new and revised data in establishing the final standards. We re-ranked all the coal-fired EGUs based on the new data. The new ranking of coal-fired EGUs resulted in a change of the source we used to establish the new source PM surrogate standard for non-mercury metal HAP. The basis for the new source limit in the final rule is a unit that has a full suite of controls similar to what would be required for any new coal-fired EGUs (*i.e.,* it is a unit with SCR, dry FGD, and FF). The EPA has identified at least one EGU meeting all of the final new source limits; thus, the EPA does not believe that it is finalizing standards that ''ban'' new coal-fired generation as indicated by the commenter.

The EPA also disagrees that the final new source standards are so stringent that there are not adequate test methods available to determine compliance with the standards. The EPA has taken into account the ability of the various test methods to accurately measure emissions at the levels being demonstrated by the best performing EGUs in establishing the final limits. This has been done through use of the 3XRDL (discussed elsewhere in this preamble and the Response to Comments document) and through adjustments to the sampling time requirements for certain of the HAP.

7. Comments on Technical Approaches

Comment: Commenters disagreed with the EPA's use of data from multiple units exhausting through a common stack and argued that the EPA unreasonably treated data from multiple units exhausting through a single stack as multiple data points in establishing the MACT floors. The commenters believe it is improper to count a single data point from a multiple-unit common stack as multiple data points. The commenters state that where two units exhaust through a common stack, the performance is not that of two sources, but only one. The commenters indicate that emissions performance that is actually achieved reflects combined operation, which cannot rationally be split into two parts (data points) because this emissions performance was not achieved by two separate sources. Commenters assert that although it may be acceptable for the EPA to surmise that the combined performance of multiple EGUs and pollution control devices represents an emissions control strategy that could be a best performer, thereby entitling the Agency to use the data at all, the fact is there is only one performer not two. Commenters contend that apart from being inconsistent with applicable MACT case law, counting combined stack emissions as two or more data points is unreasonable because it dampens variability and over-represents the emissions data by creating multiple ''performers'' or sources when there is in fact only one. Commenters note that in the major-source Industrial Boiler NESHAP, the EPA argued its approach of creating two data points from a single combined stack data point is reasonable because it cannot separate the comingled fraction of the emissions from the different emission points. Commenters state that this is irrelevant, believing that there is no basis to separate these emissions because the MACT floor is based on best performing sources and there is only a single source.

According to commenters, the EPA cannot determine what amount of the overall performance of a combined stack data point is the specific result of the combination. Commenters assert that the EPA also argues that applying the emissions equally to multiple units exhausting through a single stack ''accurately represents the emissions of those units on average.'' Commenters believe that is simply not correct and there is no plausible factual basis for that statement, believing that there is no unit that ''achieved'' those emissions. Rather, the data represent the combined weighted average of two units, without knowing how either unit actually performed. One commenter also stated that in several instances when a facility operated tandem or multiple EGUs but only submitted a single stack measurement, the EPA used the single stack measurement to represent Hg emissions from the facility's other stacks.

Response: The EPA disagrees with commenters. As in the major-source Industrial Boiler NESHAP, the EPA continues to believe that the emissions from the common stack represent the average emissions of the EGUs exhausting to the common stack and are representative of both EGUs. Commenters have provided no data to support the contention that this assumption is false. In addition, commenters' contention that distinct EGUs (*i.e.,* boilers) are one source if they emit out of a common stack is not consistent with the CAA section 112(a)(8) definition, which clearly applies to the individual boiler units with a capacity of more than 25 MW. It would not be reasonable in light of that definition to consider the emissions from two boilers to a common stack as the emissions of one EGU. The EPA only used data from combined stacks where both EGUs were operating or where the owner/operator certified that no air leakage could occur. The EPA expects that companies will comply with the final rule by conducting testing at the common stack as that is usually where the sampling locations are (rather than in the intermediate ductwork) and will report the results as being for each EGU.

The EPA has reviewed the data based on comments received and does not believe that there are any inconsistencies in the data set used for the final rule. In the MACT floor analysis, the EPA only used data from stacks that were tested or for which test data were provided. These stack measurements were not used to represent emissions from other, non-tested, stacks in the MACT analysis.

8. Alternative Units for Emission Limits

Comment: Several commenters submitted a variety of alternatives to the input- or output-based MACT floor limits as means of establishing the MACT floors. Some commenters suggested emission reductions or removal efficiencies. These commenters suggest that a percent reduction MACT metric be considered as an alternative, and not a substitute, to some of the proposed MACT numerical limits, particularly those that appear too problematic to meet in reality. A necessary data format and protocol could be developed for some HAP, such as Hg, that would allow an appropriate percent reduction alternative to be developed. Commenters believe that the Brick MACT decision stands for the proposition that a MACT level cannot be based on a specific technology; commenters are advocating that a percent reduction format would specify the level or reduction but would not dictate any specific control or methodology.

Comments were also received that some state programs contain Hg emission limits that are more stringent than the EPA's proposed emission limits. The programs of Connecticut, Massachusetts, New Hampshire, New Jersey, and New York were noted. Commenters provided information on these states' Hg emission limits, which often are in the form of either a lb/TBtu format or a percent reduction. Commenters noted that EGUs in these states were in compliance with the state regulations and, therefore, the EPA's emission limits should be more stringent.

Response: The EPA disagrees with the commenters' suggestion that a percent reduction standard should be included in the final rule. The EPA notes that the inability to account for Hg removed from the coal prior to combustion was not the only reason provided for not using a percent reduction format. As noted in the proposal preamble (76 FR 25040), we did consider using a percent reduction format for Hg. We determined not to propose a percent reduction standard for several reasons. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's desire to promote, and give credit for, coal preparation practices that remove Hg and other HAP before firing because we did not have the data to account for those practices. Specifically, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s). Such an approach would be difficult to implement and enforce. Moreover, we do not have the data necessary to establish percent reduction standards for HAP at this time. Depending on what was considered to be the ''inlet'' and the degree to which precombustion removal of HAP was desired to be included in the calculation, the EPA would need (*e.g.*) the HAP content of the coal as it left the mine face, as it entered the coal preparation facility, as it left the coal preparation facility, as it entered the EGU, as it entered the control devices, and as it left the stack to be able to establish percent reduction standards. We do not have this type of information.

The EPA believes that an emission rate format allows for, and promotes, the use of pre-combustion HAP removal processes because such practices will help sources assure they will comply with the proposed standard. A percent reduction requirement would likely limit the flexibility of the regulated community by requiring the use of a control device. In addition, as discussed in the Portland Cement NESHAP (75 FR 55002; September 9, 2010), the EPA believes that a percent reduction format negates the contribution of HAP inputs to EGU performance and, thus, may be inconsistent with the D.C. Circuit's rulings as restated in the *Brick* case (479 F.3d at 880) which say, in effect, that it is the emissions achieved in practice (*i.e.,* emissions to the atmosphere) that matter, not how one achieves those emissions.

The 2010 ICR data confirm that plant inputs likely play a role in emissions to the atmosphere. These data indicate that some EGUs are achieving lower Hg emissions to the atmosphere at a lower Hg percent reduction (*e.g.,* 75 to 85 percent) than are other EGUs with higher percent reductions (*e.g.,* 90 percent or greater). However, we are not sure whether these data accurately reflect the total percent reduction mine-to-stack because we do not have all the data necessary to make that determination. Thus, we proposed to establish numerical emission standards for Hg HAP emissions from EGUs and we are finalizing numerical emission standards. The same issues prevent us from considering percent reduction standards for the other HAP emitted from EGUs.

With regard to the comments relating to some state programs being more stringent than the EPA's proposed limits, the EPA would note that many of the programs identified by one commenter have an ''either/or'' format for their Hg standards. That is, an EGU can either meet an emission limit (*e.g.,* lb/TBtu) or achieve a percent reduction. The commenter did not note which form of the standard the EGUs were meeting so it is unclear whether the standards are in fact more stringent. In any case, CAA section 112(d) does not mandate that federal standards be more stringent than state requirements for HAP emissions. Furthermore, states are authorized to establish standards more stringent than this final NESHAP so promulgation of this rule will in no way affect a source's responsibility to comply with an otherwise applicable state Hg or other HAP standard.

9. Beyond-the-Floor

Comment: Several commenters stated that the proposed beyond-the-floor Hg limit for low rank coal EGUs is based on too little data and is technically and economically unattainable, noting that the EPA's proposed beyond-the-floor limit is based on only three samples from a single test held at only one EGU, which is not enough data to develop such a limit, especially as more data were available for this EGU in the database. Commenters noted that although this one EGU may have been able to achieve the proposed limit during this one test, the three samples are not adequate to demonstrate the long-term ability of this EGU to meet that limit consistently, let alone the long-term abilities of the top 12 percent of all low rank coal EGUs to meet that limit consistently. Given Texas lignite's particularly high rates of variability of Hg concentration, and the inability to minimize this variability, the commenters believe that the EPA is obliged to have more, not less, data to support the proposed beyond-the-floor Hg limit for low rank coal EGUs. One commenter added that the EPA's decision to require a beyond-the-floor limit for the low rank virgin coal subcategory does not comply with CAA section 112(d)(2). Some commenters also contended that the EPA failed to include the cost of a baghouse in its beyond-the-floor analysis. They note that, according to the EPA, in order to comply with the proposed EGU MACT rule, units will either fuel switch to a lower Hg fuel or retrofit air pollution controls.

Response: The EPA notes that all of the low rank virgin coal-fired EGUs for which data were submitted in response to the 2010 ICR were meeting the Hg floor limit (11 lb/TBtu). Four of the EGUs have ACI systems installed and three of the four EGUs tested were also meeting the beyond-the-floor Hg emission limit of 4.0 lb/TBtu. Those three units were achieving control levels of greater than 95 percent (fuel to stack). The other low rank virgin coal-fired EGUs that are not currently meeting the beyond-the-floor emission limit do not have installed Hg-specific controls. An analysis of the Hg content of the fuel used during the 2010 ICR testing suggests that control in the range of 80 to 90 percent (fuel to stack) would be needed to meet the beyond-the-floor limit of 4.0 lb/TBtu. One low rank virgin coal-fired EGU achieved 75 percent control with no Hg-specific control technology (*e.g.,* ACI).

The EPA believes that its beyond-the-floor analysis is appropriate, including the costs analyzed. The EPA's cost analysis is meant to serve as an average for all sources in the subcategory recognizing that some EGU's costs will be more and some less; EGUs whose costs are higher are not exempted from the regulation. Further, five EGUs in the subcategory are meeting the final beyond-the-floor limit based on available data (*see* the MACT Floor analyses in the docket), and, in any case, CAA section 112(d) does not require that a specified percentage of sources in a category or subcategory be able to meet the MACT standard that is established. This is even truer for beyond-the-floor standards which are set at levels beyond what the average of the best performing sources are achieving in practice and instead based on what is achievable. Commenters have failed to provide any data that supports the contention that some EGUs in the subcategory will not be able to achieve the standards with additional controls.

Comment: Commenters indicated that the EPA has not justified a beyond-the-floor limit for Hg for new IGCC units. The EPA's choice of the beyond-the-floor Hg limit for new IGCCs is not derived from IGCC test data from the 2010 ICR and commenters allege that the EPA has not provided adequate justification for its decision from a technology capability assessment. Commenters note that ACI for Hg treatment of coal-derived syngas is not in use in any operating IGCC plant today, nor can it be used in the same fashion as it is used at conventional coal-fired EGUs. Commenters assert that the EPA also lacks data with respect to new IGCC units, yet the EPA proposed beyond-the-floor MACT limits for new IGCC sources. The commenters assert that the EPA's limits for new IGCC sources are based on beliefs, predictions, projections and design target assumptions. The limits from the 2007 DOE Report referenced in the preamble are based on environmental target assumptions. These IGCC environmental targets were chosen to match Electric Power Research Institute (EPRI) design basis from their Coal Fleet for Tomorrow Initiative. Commenter states that EPRI notes that these were design targets and were not to be used for permitting values. Commenters assert that the EPA has simply not justified its process for going beyond-the-floor for new IGCC units and that, without sufficient justification, the EPA actions are unsupported.

Two commenters provided permit information, based on IGCC units currently under construction, for PM and Hg emissions. One commenter requested that the proposed new MACT floor limit for PM be modified to address the two scenarios for duct burners at IGCC plants, syngas-fired and natural-gas-fired. The commenter requested the 0.050 lb/MWh limit be increased to at least 0.068 lb/MWh based on gross energy output from the combined cycle generating unit when operated with duct burners fired with syngas. The 0.068 lb/MWh value is consistent with the calculated emission ceiling for its permit to construct for this operating scenario. According to the commenter, there is not sufficient experience with syngas turbines for manufacturers to guarantee performance in the 0.050 lb/MWh range. The 0.0681b/MWh performance basis proposed by the commenter was calculated based on the emission guarantees that the commenter was able to obtain for a turbine fired on the syngas. The commenter also requested that the 0.050 lb/MWh limit be increased to 0.083 lb/MWh based on gross energy output from the combined cycle unit when operated with duct burners fired by natural gas. The commenter indicated that, depending on market conditions, the syngas produced at an IGCC may have more value as a raw material for producing co-products than it would have as duct burner fuel. Where that is the case, the economic viability of an IGCC would be enhanced by firing the duct burners on natural gas and diverting that syngas to manufacture of a co-product. The commenter's air permits are currently based on the use of syngas as duct burner fuel; however, the commenter is currently examining an alternative operating scenario that may result in amendments to the air permits to authorize firing natural gas in the duct burners. Commenter states that preliminary calculations indicate that the PM limit would need to be set at 0.083 lb/MWh gross energy output when operated with duct burners fired with natural gas.

The commenter also noted that there is not sufficient test data to precisely predict the Hg emissions performance of even the best-controlled IGCC units, other than that IGCC Hg emissions are expected to be much less than those for EGUs that directly burn coal. In its permit application, the commenter proposed to establish a new standard for Hg removal in IGCC units by treating the syngas in catalytic reactors. The catalytic reactor system is expected to achieve greater than 95 percent Hg removal using either sulfur-impregnated activated carbon or alumina catalyst. In the absence of actual stack test data, the commenter has had to estimate expected emissions based on engineering estimates of how much Hg may arrive in the syngas routed to the catalytic reactors. Based on these engineering estimates and 95 percent Hg removal in the catalytic reactors, the commenter believes that the resulting Hg emission limit for a state-or-the-art IGCC unit would be 0.003 lb/GWh, which is much less than the Hg emissions for EGUs that directly burn coal.

The commenter notes that IGCC units are still in their infancy. Funding for them will be very difficult or unavailable if there is a regulatory limit below the level that can be supported by vendor guarantees. Given the important role that IGCC units may have in meeting global energy and climate stability goals, the commenter believes it would be a mistake to erect barriers to the implementation of this technology. The commenter stated that the EPA can reevaluate the appropriate levels for future IGCC units after demonstration units which incorporate effective controls have been built and tested.

Response: The EPA is not finalizing the proposed new source standards for IGCC units. As commenters noted, EPA proposed beyond-the-floor limits for IGCC units based on the performance of PC-fired EGUs and solicited data from IGCC units that would represent what a new IGCC could achieve. We received information that there are new IGCC units permitted and under construction. The EPA believes one IGCC unit under construction for which permit data were provided is representative of both current technologies and of IGCC units that will be built in the near-term future. Therefore, the EPA believes these permit levels should be the basis of the new source IGCC emission limits and the Agency is finalizing the PM and Hg limits on that basis, as that source will be required to comply with its permitted limits once constructed and it is a similar source. However, permit limits were only provided for PM and Hg; therefore, the EPA is finalizing the new source limits for acid gas HAP based on data from the best-performing of the existing IGCC units for the respective HAP.

B. Rationale for Subcategories

Many commenters stated that the EPA should have proposed more subcategories, while others believed that too many subcategories were proposed. Many different issues were raised by commenters, and some of the key issues that were considered in the final rule (some of which led to changes in the final rule) include: the technical deficiencies in the definition for the low-Btu coal subcategory; additional subcategorization of the coal-fired EGU population; the need for subcategorization of distillate vs. residual oil-fired EGUS; the need for a limited-use subcategory for EGUs that operate for only a small percentage of hours during a year; and the need for a non-continental liquid oil subcategory for island units that have limited fuel options and other unique circumstances. The comments and the EPA responses are provided below.

In general, the EPA has reviewed the data provided and continues to believe that the coal-fired EGU subcategories proposed are the only ones supported by the data, though we have revised the basis for EGUs designed to burn low rank virgin coal as discussed above. The EPA may not subcategorize by air pollution control technology type as requested by a few commenters. Further, the EPA has reviewed the other suggested coal-fired subcategories and finds no basis for further subcategorization (*e.g.,* based on boiler design, boiler size, or duty cycle).

1. Coal Subcategories

Comment: Commenters noted that although other subcategories had been evaluated, including subcategorization of other coal ranks, no other coal rank subcategorization was proposed. Commenters submit there should be subcategories for the coal ranks of bituminous, subbituminous, and lignite. The commenters noted that such treatment would be consistent with past practice (*e.g.,* CAMR where the differences in the type of emissions of Hg due to the different chemical properties of coal within differing fuel ranks was discussed). Commenters note that activated carbon has been shown to be very effective when used in combination with low chlorine coals (such as western subbituminous coals); however, activated carbons can suffer from poor performance when used with high sulfur coals. Commenters indicate that firing high sulfur coals (especially when an SCR is also used) can result in sulfur trioxide (SO_3) vapor in the flue gas stream. The SO_3 competes with Hg for binding sites on the surface of the activated carbon (or unburned carbon) and limits the effectiveness of the injected activated carbon. But another commenter noted that an SO_3 mitigation technology, such as dry sorbent injection (DSI, *e.g.,* trona or hydrated lime), applied upstream of the ACI can minimize this effect.

Commenters also stated that without further subcategorization the economic impacts on individual Midwestern states will be particularly acute as huge segments of the U.S. coal reserve will be disenfranchised by this rule. According to the commenters, the EPA did not even attempt to legitimately analyze this issue and, thus, in their opinion the Agency's proffered rationale for declining to further subcategorize based on the acid gas standard is belied by the record. The commenters believe that the EPA needs to better align this rule with its previous position in CAMR and further subcategorize based on coal type.

Other commenters are opposed to any further subcategorization based on coal rank. Because many sources blend several ranks of coal on a regular basis, commenters believe that establishing coal rank subcategories would create numerous opportunities for sources to game the regulations and substantially increase emissions. Commenters stated that there is no need for such an approach since modern pollution controls can accommodate a wide range of coals. These commenters believe that EGUs firing different ranks of coal are not fundamentally different in size, class, or type in a way that impacts emissions or that limits the availability of controls. The commenters believe that emissions of fuel-dependent HAP can be controlled by either changing the fuel prior to combustion or by removing the HAP from the flue gas after combustion. Commenters state that ACI systems, DSI controls, and PM controls are available for installation at units firing sub-bituminous coal and are equally available for units firing bituminous, anthracite, or lignite coal. These commenters also believe that as long as a control option is commercially available, the cost for a particular EGU is irrelevant to the EPA's development of emission standards based on MACT. Commenters stated that subcategories based on coal rank would make a meaningful consideration of fuel switching impossible, contrary to the judicial mandate to consider substitution of materials in setting the floor and the statutory mandate to consider substitution of materials in the beyond-the-floor analysis.

One commenter stated that although they previously supported the subcategorization of coal-fired units on the basis of coal rank, they no longer object to grouping units that burn bituminous and subbituminous coals in a single category because the prior basis for subcategorization no longer exists. The commenter indicated that at the time of CAMR, it was widely recognized that although coal-fired units combusting bituminous coal, with its higher concentration of chlorine and, therefore, ionic Hg, could effectively limit Hg emissions by utilizing existing control technologies such as scrubbers, units burning subbituminous coal could not do so with the same controls because of the coal's higher levels of elemental Hg. The commenter stated that activated carbon was only a fledgling and unproven technology at the time; today, however, activated carbon has been proven, and units burning bituminous and subbituminous coal can achieve the same levels of emissions for Hg and other HAP. Consequently, the commenter believes the prior basis for subcategorization no longer exists and the commenter, therefore, agrees that coal-fired EGUs burning bituminous and subbituminous coals ought to be grouped in a single category.

Response: The EPA disagrees with commenters that additional coal-fired subcategories are warranted and has not provided any in the final rule. Commenters are correct that additional subcategorization was proposed in January 2004. Whether or not such subcategorization was warranted at that time, the EPA believes that the current conditions are such that, even if appropriate at that time, such further subcategorization is not appropriate at this time.

When all of the factors noted by commenters have been reviewed, with the exception of Hg for certain units, as discussed above, the EPA does not believe that the HAP emissions to the atmosphere are sufficiently different from coal-fired EGUs to warrant further subcategorization. There are EGUs firing bituminous, subbituminous, and coal refuse among the top performing units for Hg and EGUs firing bituminous, subbituminous, lignite, and coal refuse are all among the top performers for the acid gas HAP and non-mercury metallic HAP indicating that the MACT floor limits established based on these units are achievable by units burning all ranks of coal.

As noted by commenters, ACI, not fully developed in 2004, is now able to effect Hg control levels on subbituminous coals such that similar emissions to the atmosphere may be achieved as those achieved by higher-chlorine bituminous coals when FGD systems are used or by coal refuse EGU with less controls. Thus, in looking at the total system, similar emissions to the atmosphere are achieved by all of these coal ranks. The EPA has addressed elsewhere in this document its rationale for not subcategorizing by coal chlorine content. The EPA does not believe that any fundamental discrimination between coal ranks will occur as a result of the final rule, though clearly some sources will be required to install greater controls to comply with the final standard. We maintain that such result is consistent with the intent of CAA section 112 standards, which are not intended to have an outcome whereby all sources can comply with final standards without any action.

The EPA agrees, in theory, that EGUs are designed around a basic set of coal characteristics. However, the 1999 ICR demonstrated that numerous EGUs have conducted trial burns and gained sufficient experience such that co-firing blends of various coal ranks is now common practice. In fact, the EPA believes that such blends may be modified daily, depending on the characteristics of the coal being burned and on the level of generation needed. The extent of blending, and the ability to switch the blends on short notice, does not lend itself (or, in fact, argue for) additional subcategorization.

The EPA disagrees with any assertion that the EPA ignored possible subcategorization approaches or that it has insufficient data upon which to base or evaluate various subcategories. The EPA fully examined the record, which demonstrates that coal-fired EGUs, with the exception of certain units for Hg, have similar HAP emissions profiles and that similar control approaches are available to such EGUs. Although commenters suggested additional subcategories were warranted, they failed to provide sufficient data to support their proposed alternative subcategories. As noted elsewhere, the EPA does not disagree with commenters that there are some differences in EGUs. However, the EPA does disagree with commenters that those differences result in differences in emissions to the atmosphere such that additional subcategorization is justified.

Failing to demonstrate that coal-fired EGUs are different based on emissions, the commenters turn to economic arguments, asserting that failing to subcategorize will impose an economic hardship on certain sources. Congress precluded consideration of costs in setting MACT floors, and it is not appropriate to premise subcategorization on costs either. See S. Rep No. 101–228 at 166–67 (5 Legislative History at 8506–07) (rejecting the implication that separate categories could be based on ''assertions of extraordinary economic effects''); *see also NRDC* v. *EPA* 489 F.3d 1364 (D.C. Cir. 2007) (holding that EPA properly declined to create a subcategory for a particular source and rejecting the argument that the source may have to incur more costs to comply with the rule without such subcategory).

The final limits are based on EGUs currently operating with available controls. As noted above, the record shows that the various types of EGUs are represented in the floors, with the exception of certain units for Hg, which indicates that the levels are achievable by such units. Thus, the data actually show that the MACT standards are achievable for a wide variety of EGUs.

In addition, the EPA believes it has fulfilled the CAA section 112(c)(l) directive that ''[t]o the extent practicable, the categories and subcategories listed under this subsection shall be consistent * * *'' with those of CAA section 111, notwithstanding commenters assertion to the contrary. The decision on whether to directly align CAA sections 112 and 111 subcategories is discretionary and EPA has reasonably exercised its discretion in declining to create additional subcategories for coal-fired EGUs based on the record, with the exception of certain sources for Hg.

Finally, the EPA disagrees with the commenters that suggest that EPA lacks the legal authority to consider material inputs when considering subcategories. We agree, however, that material inputs must be considered when establishing MACT standards for the subcategories that are established. We also believe a meaningful consideration of fuel switching can occur even if sources are subcategorized based on fuel inputs because EPA considers fuels switching in evaluating potential beyond-the-floor alternatives.

Comment: One commenter stated that the EPA should establish an existing source acid-gas subcategory for high sulfur or high chlorine coals because the same factors that the EPA relied on to support a low rank virgin coal subcategory for Hg are also present in the high sulfur or high chlorine coal context. The commenter stated that the data indicate that even well-controlled units burning high sulfur coals would not be in the top performers for acid gases even at removal rates of 95 or 96 percent. The commenter added that absent such a subcategory, about 12 percent of coal deliveries (2005 data), and the vast majority of coal shipped from the states of Indiana, Ohio, and Illinois (2008 data), would become unusable. The commenter expressed support for the alternative SO_2 standard for units unable to meet the HCl standard; however, the commenter also believed that it is appropriate to establish a coal chlorine or sulfur content-based subcategory for the alternative SO_2 standard. The commenter stated that coal testing data indicate a clear break in chlorine concentrations in the coals burned by EGUs, as well as in sulfur content. The commenter indicated that there are factors supporting a high sulfur or high chlorine coal subcategory that are similar to those that the EPA relied upon to support a Hg subcategory for low rank virgin coal. According to the commenter, the EPA's key rationale for a Hg subcategory for low rank virgin coal was that no low rank virgin coal-fired unit appeared in the ''top performing 12 percent of sources, indicating a difference in the emissions for this HAP from these types of units.'' The EPA did not establish other subcategories because ''the data did not show any difference in the level of HAP emissions and, therefore, we have determined that it is not reasonable to establish separate emissions limits for other HAP.'' The commenter indicated that the EPA does not need emissions data to know that even well-controlled units burning higher sulfur coals would be unable to meet the alternative SO_2 emissions rate, and would therefore also not appear in the top 12 percent of performing units.

Response: The EPA disagrees with commenters that subcategories should be established for high sulfur and high chlorine coals. It appears from the comments that it is not in fact the chlorine content that is at issue but the sulfur content of the coal. Commenters state that they are unable to meet the HCl limit, but they only provide information indicating it would be difficult to meet the alternative equivalent SO_2 limit. In fact, our data show that coals with chloride contents as high as 2,100 ppm (0.16 lb/MMBtu) were burned by EGUs making up the MACT floor pool of sources for the final HCl emission limit and that the best-performing unit was burning coal with a maximum chloride content of 1,200 ppm. The median chloride level for bituminous coals identified from data submitted through the 1999 ICR was 1,030 ppm so we believe that the coals represented in the MACT floor pool indicate that the final limits are achievable with high-chlorine coals. We have determined that HCl removal is very effective using a number of different types of FGD systems. Absent information demonstrating that sources are unable to meet the proposed HCl limit due to the chlorine content of the coal, we believe it is unnecessary and inappropriate to consider subcategorizing based on chlorine content in the coal.

In addition, as noted above, the SO_2 limit is an alternative equivalent standard that is available to sources that have an SO_2 control and CEMS and operate the controls at all times. The EPA did not provide the alternative equivalent standard for sources that could not meet the HCl limit as one commenter suggests; instead, we provided the standard as a convenience and cost saving measure to EGUs with installed FGD systems because we recognize that many EGUs have SO_2 CEMS. Sources are required to comply with the HCl limit as a surrogate for all the acid gas HAP or the SO_2 limit as an alternate equivalent standard. Commenters have not demonstrated that they are unable to meet the HCl standard and our data show that the standard is achievable even for high chlorine coals.

Comment: Several commenters supported the development of a separate subcategory for fluidized bed combustors (FBC) or circulating fluidized bed (CFB) EGUs. The commenters encouraged the Agency to consider subcategorization of FBC EGUs for Hg emissions noting that the industry has long contended that the design, construction, and operation of FBCs are different than conventional boilers and that FBCs employ fundamentally different processes than conventional PC-fired EGUs. The selection of an FBC unit over a conventional PC boiler is driven in large part by fuel characteristics. The commenters assert that, as a result, the emissions profile of FBC units generally differ from conventional PC boilers because FBC units more advantageously combust waste coals, as well as coal blends with other carbonaceous material. The commenters stated that the EPA did not discuss the design differences between FBC units and PC units in the preamble to this proposed rule unlike what the Agency did when it previously proposed Hg MACT limits in January 2004. Commenters state that, for these reasons, FBC units can be considered a distinct type of boiler.

The commenters noted that an examination of the 40 ''best performing'' units for Hg emissions in the proposed MACT floor spreadsheet showed that 14 of those units are FBC units. The commenters maintained that had FBC units performed as well as conventional PC boilers, 2 units would have been expected to be in the top 40. The commenters allege that the far higher percentage of FBCs in the top 40 leads to the conclusion that these units are different from conventional PCs with regard to Hg emissions and, as a result, should have been placed in their own subcategory. Further, commenters noted that the largest FBC has a nameplate capacity of about 300 MW while the largest conventional boilers have nameplate capacities of around 1,300 MW.

The commenters stated that FBCs combust relatively large coal particles in a bed of sorbent or inert material at a lower degree of combustion efficiency.

Fluidized bed units operate at less than half of the temperature of a conventional boiler and have much longer fuel residence times. Conventional boilers pulverize coal to a very fine particle size to maximize combustion efficiency and minimize unburned carbon. As a result, the commenters noted that FBCs typically have higher levels of unburned carbon present in the ash, which behaves much like activated carbon and helps promote more efficient Hg removal. Accordingly, commenters maintain that Hg emissions of FBC boilers and PC boilers are statistically different, with emissions from FBCs significantly lower than those from PC boilers. According to commenters, this statistically significant difference in the Hg emissions profiles for these two distinct boiler technologies argues in favor of the creation of a separate subcategory for FBCs, as there is no control technology that PCs could install that would result in emissions reductions similar to those achieved by FBCs. The active quantity of calcium oxide (lime-CaO) available in a FBC boiler is also orders-of-magnitude greater than compared to a PC boiler, whose alkalinity is derived solely from the coal's mineral content. Significantly higher CaO can alter the process chemistry in the boiler, including the oxidation levels of Hg.

One commenter stated that the EPA properly declined to subcategorize units based on design type where there is no indication that any physical distinctions among unit designs have a meaningful and substantial impact on HAP emissions. The commenter indicated that it would be inappropriate to subcategorize FBCs because there is no evidence to support a determination that FBC design is responsible for a unit falling in or out of the top 12 percent for a particular HAP.

Response: The EPA acknowledges that there are design and operation differences between conventional PC-fired EGUs and FBC/CFB EGUS; however, the commenters are incorrect in asserting that the HAP emissions levels and characteristics are sufficiently distinct from other coal-fired EGUs to support subcategorization. Further, commenters fail to note that FBC EGUs were not subcategorized in CAMR even though, as commenters note, such design and operation differences were cited there. The fact that FBC units operate at lower temperatures is of no consequence as they still operate at temperatures high enough to vaporize Hg.

Commenters assert that FBC units are disproportionately represented among the best performers, with the inference being that they were selected to test in the 2010 ICR because of their boiler design. However, FBC EGUs were not specifically selected as best performers for Hg, as EPA did not select any EGUs based on a determination that they were best performers for Hg (as noted elsewhere, we had no basis for selecting EGUs as being best performers for Hg), and to the extent CFB units were selected in the 2010 ICR, they were selected because we determined they were best performers for non-mercury metallic HAP, acid gas HAP, or organic HAP or because they were randomly selected among the non-best performers for those three HAP groupings. Thus, the CFBs were selected for testing under the 2010 ICR based not on their boiler design but, rather, based on the age and on their PM and FGD control systems (as noted in the Supporting Statement for the 2010 ICR). As many FBC EGUs, including CFB EGUs, are relatively new, they were included in the non-mercury metallic HAP group selected for testing (because their PM controls were among the 175 newest), the acid gas HAP group selected for testing (because FBC was considered to be an FGD system and the units were among the 175 newest), and organic HAP testing (because they were among the newest and, thus, determined to be among the most efficient).

The effect on Hg emissions is not what commenters suggest because, although, as noted by commenters, FBC units may be found among the better performers (among the top 10 EGUs) on the Hg MACT floor spreadsheet, they are also found in the range of 221 to 226 EGUs (of 393 data points). The fact that FBC units have ''vastly dissimilar ash properties'' that may contain higher levels of lime or unburned carbon in the fly ash than conventional PC EGUs does not indicate that the overall system behaves any differently with regard to emissions to the atmosphere (the key metric) than a conventional PC EGU with add-on controls. The asserted higher levels of unburned carbon result in a range of effectiveness of Hg control that is similar to that of ACI found on PC EGUs; such ACI control may be found on EGUs that are among the better performers as well as on EGUs as low as 369 on the list of data points. Thus, the EPA disagrees that FBC units are disproportionately represented in the Hg floor and that their inclusion is somehow inappropriate or leads to skewing of the analysis.

All types of coal-fired EGUs other than those we subcategorized are represented in the MACT floors for Hg and all types of EGUs are represented in the floors for the non-mercury HAP. Fluidized bed combustion EGUs are not an exception and such EGUs are found across the range of top performing EGUs for all of the HAP categories: Acid gas, non-mercury metallic, and Hg. In addition, any assertion that non-FBC EGUs are unable to meet the final standards because FBC EGUs are included in the same subcategory (or vice versa) is plainly refuted by the fact that EGUs of all types are currently meeting one or more of the final standards. Thus, the EPA finds no basis for subcategorizing FBC EGUs.

Further, as noted below, the EPA does not believe there is a basis for subcategorizing small EGUs, either FBC or PC. In addition, the data have been re-evaluated based on comments received and an FBC unit is not the basis for the new source Hg MACT floor.

Comment: Many commenters stated that the EPA should have considered additional subcategorization schemes, including one based on EGU size. Commenters noted that one of the factors that the Administrator can consider under CAA section 112(d)(1) in making subcategorization decisions is unit size. Commenters stated that an analysis of the 2010 ICR data showed a statistical difference between EGUs with a capacity of 100 MW or less and EGUs above 100 MW; other commenters suggested that the cut-off range should be 125 MW. Although large in number (about 27 percent) of all EGUs, these small EGUs only comprise about 5 percent of the coal-fired capacity in the U.S. Thus, commenters assert that if different MACT limits are set for this subcategory of EGUs, it will not have a significant impact on the health effects of HAP emissions. Commenters noted that although emission rates from such small EGUs are greater than those found in the large unit fleet, their contribution to the total EGU emissions is not significant. The costs associated with coming into compliance with the proposed rule by installing new controls would be proportionally much higher for these small EGUs than larger EGUs according to the commenters. The commenters allege that this would force the retirement of generation capacity and threaten electrical reliability without appreciable benefit to the environment.

One commenter stated that in general, the nature of many public power facilities differs from the general population of coal-fired power plants. Public power units tend to be smaller in size, and are often space-constrained by growth in the community surrounding the generating unit since its initial construction. These limitations restrict the ability of these EGUs to achieve the same performance levels of larger, unconstrained EGUs; and, for those EGUs that can comply with the proposed standards, the installation of controls sharply increases the cost of compliance. The commenter stated that the EPA did not adequately subcategorize to accommodate many small- and medium-sized public power utilities. In particular, the EPA did not avail itself of the opportunity to use a public power electric utility subcategory, rural subcategory, or fuel type subcategories. Other commenters endorsed the establishment of a less than 100 MW subcategory that would reduce the costs of the proposed rule significantly, but only affect 5 percent of the total electric utility sector, and help minimize retirement of uneconomical plants.

One commenter stated that the EPA properly recognized that subcategories based on unit size would be inappropriate because the proposed emission limits are in terms of lb/MMBtu or lb/TBtu and noting that an EGU's total nameplate capacity is wholly unrelated to its ability to achieve the proposed limits. Another commenter opposed any proposal to subcategorize units below 100 MW. The proposed rule does not apply to units less than or equal to 25 MW, and this commenter believed that this is a sufficient threshold for applicability.

One commenter stated that the EPA could establish subcategories for the purpose of temporarily exempting, for example, a subcategory of utilities that meet the definition of small entity for purposes of the proposed rule. The temporary exemption would sunset on a date certain (e.g., 3 years from the effective date of the rule) at which point the sources in the subcategory would become subject to the rule, and a compliance timetable would start to run. The commenter believed that this time-staged promulgation and compliance proposal would greatly increase the chance that the control measures could be added in an orderly and efficient manner with minimal disruption to power markets and grid reliability.

Response: The EPA agrees with commenters who stated that an EGU's size is totally unrelated to its ability to comply with the final concentration-based limits. The EPA examined the size of units within the respective MACT floor pools of sources and found units ranging in size from 25 to 1,320 MW in the HCl floor pool, from 25 to 869 MW in the non-mercury metallic floor pool, and from 47 to 544 MW in the Hg floor pool. Thus, we find no more difference between a 25 MW EGU and (e.g.) a 500 MW EGU than we do between a 500 MW EGU and a 1,300 MW EGU and reaffirm our position that the MW capacity of the EGU is not a determining factor in its emissions. Further, the EPA believes that units of all sizes are owned by both large and small entities.

The EPA examined the effect if EGUs less than 125 MW were subcategorized for Hg. The resultant MACT floor for these EGUs would be 1.0 lb/TBtu on a 30-boiler operating day rolling average, a level more stringent than that developed for the >8,300 Btu subcategory as a whole. We do not believe that this is what commenters envisioned when suggesting such a subcategory but we believe it confirms our analysis of the data that indicates, as noted, these units are controlled in the same manner as other, larger EGUs, such that additional subcategorization is not necessary or reasonable. Further, based on the number of EGUs less than 125 MW in the HCl and PM MACT floor pools, we believe that a similar analysis for HCl and PM would lead to similar or more stringent standards than without the additional subcategory. Thus, units of all sizes are capable of achieving the proposed limits and the EPA is not finalizing a subcategory based on unit size in the final rule.

The CAA authorizes EPA to subcategorize based on ''classes, types, and sizes of sources.'' The EPA does not believe that this provision permits subcategorizing sources based solely on their status as small entities for several reasons. As a threshold matter, commenters provided no information to suggest that EGUs at small entities are different from EGUs owned by other entities. Instead, the commenters' justification for such a subcategory was that the costs to comply with the standards make it more difficult for small entities; thus, the basis is essentially a cost basis and we do not think that is consistent with the statute. Moreover, the legislative history of CAA section 112(d) supports EPA's interpretation that subcategories cannot be based on the cost of compliance. *See* S. Rep No. 101–228 at 166–67 (5 Legislative History at 8506–07) (rejecting the implication that separate categories could be based on ''assertions of extraordinary economic effects'').

In addition, the EGUs owned by small entities use the same type of fuel as other units, have the same type of combustor designs, and can use the same types of controls, and so there is no difference in the HAP emissions from such units. So, even if we believed a subcategory based on small entities was consistent with the statute, we would decline to include such a subcategory.

Therefore, given the language of CAA section 112(d), the legislative history, and the available information, EPA is not creating a separate subcategory for EGUs owned by small entities.

In addition, the D.C. Circuit has clearly stated that the EPA does not have the statutory authority under CAA section 112 to extend compliance dates past the 3-year maximum compliance time authorized in CAA section 112(i)(3)(A) except consistent with CAA sections 112(i)(3)(B) and 112(i)(4). *See NRDC* v. *EPA,* 489 F.3d 1364, 1374 (D.C. Cir. 2007) (finding that ''Congress enumerated specific exceptions to the 3-year maximum, which indicates that Congress has spoken on the question and has not provided the EPA with authority under subsection 112(i)(3)(B) to extend the compliance date * * *'') (citing also CAA section 112(i)(4)). The EPA may not alter the compliance date based on size or ownership considerations and, thus, we are not providing a separate compliance date for different groups of EGUs in the final rule.

Comment: One commenter stated that the EPA should establish a subcategory consisting of EGUs that had received air construction permits but had not yet commenced construction as of the date of the EPA's proposed rule. The commenter believed that such a category would be justified because a substantial amount of time, money, and effort has been invested in these units. The commenter asserted that imposing new source standards on these EGUs for which the EPA's proposed rule had not been anticipated during their permit consideration would unreasonably and arbitrarily impose additional costs and burdens on these projects and would likely threaten the viability of many of them. The standards for this subcategory would be based on the anticipated performance of these units (as reflected by the permitted case-by-case emission levels), ensuring a reasonable and appropriate level of HAP control without unreasonably and arbitrarily interfering with the development of these units.

Response: Clean Air Act section 112(a)(4) defines a new source as ''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.'' The EPA's regulations implementing the CAA section 112 General Provisions define ''commenced'' to mean ''with respect to construction or reconstruction of an affected source, that an owner or operator has undertaken a continuous program of construction or reconstruction or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or reconstruction.'' *See* 40 CFR 63.2.

The EPA is constrained by the definition of ''new source'' such that any source that ''commenced'' construction after the May 3, 2011, proposal date is considered a new source under the statute and the source must comply with the new source standards even if the source received a final and legally effective CAA section 112(g) permit before proposal. It is unclear from the comments whether the sources identified in the comments have commenced construction as defined in the regulations; however, the identified sources are existing sources, not new sources, under the final rule if construction was commenced prior to the proposal date.

Under the final rule, new sources must comply with the standards on the date of promulgation or at startup, whichever is earlier, and existing sources have 3 years to come into compliance with the final standards. Pursuant to the EPA's regulations at 40 CFR 63.44(b)(1), however, we may provide in a final CAA section 112(d) standard a specific compliance date for those sources that obtained a final and legally effective CAA section 112(g) case-by-case MACT standard and submitted the information required by 40 CFR 63.43 to the Agency before the close of the comment period. The EPA does not believe it has received such information during the comment period and we are not establishing a separate specific compliance period for sources that obtained final and legally effective CAA section 112(g) standards prior to promulgation of the final rule. In the absence of EPA action on this issue, state Title V permitting authorities are required to ''establish a compliance date in the [title V] permit that assures that the owner or operator shall comply with the promulgated standard [ ] as expeditiously as practicable, but not longer than 8 years after such standard is promulgated * * *'' 40 CFR 63.44(b)(2). Sources with final and legally effective section 112(g) standards should work with their permitting authorities to determine the appropriate compliance date consistent with the EPA regulations.

Comment: One commenter stated that in accordance with CAA section 112(d)(l), based on the government-to-government relationship of the Navajo Nation and the U.S. government, and consistent with the right of sovereignty and self-determination of the Navajo Nation, it may be appropriate to classify EGUs on tribal lands in a different subcategory from those on non-Indian lands. The commenter stated that in accordance with the distinctive status of Indian lands, based on principles of tribal sovereignty and self-determination, the government-to-government relationship, and the flexibility of federal agencies mandated under E.O. 13175, the EPA should classify sources on tribal lands as a unique subcategory of EGUs for which emission standards for NESHAP should be set pursuant to CAA section 112(d)(3).

Response: Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. In the preamble to the proposed rule, the EPA further explains that any basis for subcategorizing (*e.g.,* class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not agree that a subcategory based on location on Tribal lands is consistent with the statutory authority to subcategorize, and commenters do not explain why emissions would be different for EGUs located on Tribal lands. Absent that showing, EPA believes it would not be appropriate to subcategorize units even if we believed such a subcategory is consistent with the statute. CAA section 112 imposes specific requirements with respect to the methodology that the EPA must use in establishing emission standards for HAP, including Hg emissions from EGUs. Pursuant to CAA section 112(d)(1), the EPA may subcategorize sources based on differences in class, type, or size. The EPA believes, that any basis for subcategorizing (*e.g.,* class) must be related to an effect on emissions, rather than some difference which does not affect emissions performance.

However, the EPA is sensitive to the commenters' concerns and particularly recognizes the significance of Navajo Generating Station to the Central Arizona Project and the water delivery to tribes. As a result, EPA has been consulting with affected Indian tribes and working closely with other federal agencies, including the Department of the Interior, on these issues and intends to work with tribal and other authorities to ensure a smooth transition and address specific issues as they arise.

2. Oil Subcategories

Comment: Several commenters stated that distillate oil, and in particular ultra-low sulfur diesel (ULSD) oil, has fuel characteristics closer to that of pipeline gas than to residual oils. The metals, as well as the ash and nitrogen content, of distillate oils are very low, and the sulfur content of ULSD is approximately the same as that of pipeline natural gas. The commenters state that distillate oil is a more refined product than residual oil and, thus, burns cleaner. According to commenters, separating liquid oil-fired EGUs into two subcategories (distillate and residual oil) would be consistent with the discussion of subcategory differentiation in the rule's preamble which indicates that the division of a category into subcategories is justified if the two subcategories have very different emissions, which is true for distillate vs. residual oils. Distillate and residual oils are also differentiated by their operating requirements. Some commenters stated that as a consequence of the mechanical differences between boilers designed for residual oil vs. distillate oils, and between the fuel-handling requirements for the different fuels, it is not possible to interchange oil types without significant modifications to the oil storage tanks, transfer pumps, piping and valves, flow control systems, burners, and burner control systems. Commenters also noted that some of the EGUs in the EPA's liquid oil-fired database were mischaracterized with regard to the type of oil burned during the 2010 ICR testing.

Some commenters alleged that by combining distillate and residual oil into a single MACT category, the resultant MACT standards cannot be satisfied by a boiler firing residual oil without substantial add-on controls. The commenters asserted that creation of separate subcategories for liquid oil-fired units that distinguish between residual and distilled oil would render the standards more achievable for distinct subcategories of EGUs and reduce the number of potential plant closures while still advancing the goal of reducing overall emissions. These commenters contend that MACT floors should not be used to eliminate whole classes of existing EGUs through mathematical floor calculations based on data from uncontrolled units and combining boiler subcategories that are not capable of accommodating a different fuel.

One commenter stated that the EPA should not subcategorize liquid oil-fired EGUs based upon different grades of liquid oil. Although different grades of liquid oil may vary in their heat contents or viscosities, the commenter maintained that there is no indication in the rulemaking record that any physical distinction among units burning different grades of liquid oil affects the nature or characteristics of emissions in a way that impacts the availability of controls. According to the commenter, both distillate and residual oil-fired units can apply similar control technologies to reduce HAP emissions, and EGUs firing these fuels do not have physical distinctions that prevent controls from operating effectively. The commenter believes that fuel switching is an appropriate control technology and is available for liquid oil-fired sources. Residual fuel oil contains higher levels of contaminants, including HAP, than distillate oil, and because a regulated entity can readily burn cleaner distillate oil in lieu of residual oil, it is inappropriate to subcategorize based on the distillation fraction of the liquid oil. Thus, according to the commenter, the grade of liquid-oil fuel does not provide a reasonable basis for subcategorizing various groups of liquid oil-fired EGUs. Another commenter alleges that the EPA did not list distillate oil-fired EGUs in the 2000 Finding.

Response: The EPA has reviewed the data and determined that it is not necessary to subcategorize distillate vs. residual oil. Commenters had noted that the EPA's MACT Floor Analysis spreadsheet at proposal had erroneously assigned the oil type used during testing for some boilers. The EPA reviewed the data and determined that the submitting companies had entered the data incorrectly, or had indicated that two types of oil were fired in different parts of the 2010 ICR responses. The EPA contacted all of the companies with oil-fired EGUs in the 2010 ICR to confirm the oil used during testing. Upon review of these data, it became apparent that units using residual oil with ESPs or distillate oil without control were the best-performing oil-fired EGUs for PM and the HAP metals. Further, although emissions of HAP from distillate oil-fired EGUs are generally lower than those from residual oil-fired EGUs, EGUs burning distillate oil appeared to have higher emissions of some HAP but lower emissions of others.

In addition, the EPA does not agree that distillate oil-fired EGUs were not listed in the 2000 Finding. We believe it is inappropriate to exclude distillate oil-fired EGUs from regulation under the final rule because the Agency did not make a distinction when listing the oil-fired units.

The EPA also disagrees with commenters that by providing the distillate vs. residual oil subcategories as requested, the resultant standards would be more achievable. Were the EPA to subcategorize distillate oil from residual oil, the users of distillate oil would have no means of compliance other than obtaining ''compliance'' oil from their distributor (which was not indicated as an option by any commenter) or converting to natural gas and being removed from the subcategory. With no further subcategorization, oil-fired EGUs have the option of installing an ESP or converting to distillate oil for compliance. Commenters did not contend that it was impossible to convert to distillate oil, only that it would require plant modifications. Installing controls would also require plant modifications so sources will be able to evaluate the options and determine the most cost-effective option to comply with the final rule. CAA section 112 is intended to be a technology-forcing statute, and, because both distillate oil- and residual oil-fired EGUs were among the best performing sources in the floor and both types are meeting the final standards, we cannot reasonably conclude that the HAP emissions characteristics of these similar types of units are distinct. Therefore, the EPA is not establishing separate subcategories for distillate and residual oil-fired units in the final rule.

3. Limited-Use Subcategory

Comment: Several commenters stated that EPA should establish a limited-use subcategory for liquid oil-fired EGUs that are required to burn oil during periods of natural gas curtailment. One commenter stated that under New York State Reliability Council Rules, their facility is required by the New York Independent System Operator (NYISO), for reliability purposes, to maintain the capability to burn oil and actually burn oil, from time to time, at varying load levels to help avoid or avert potential natural gas shortages in New York City. The requirements to burn oil under this program are mandatory and are not within the commenter's discretion. The reliability rules require that the commenter's EGUs maintain their co-firing capability to respond to unplanned, emergency scenarios by operating on oil during required minimum oil burn periods, typically 25 percent oil/75 percent natural gas. The commenter noted that operation using oil at other times or on 100 percent oil during reliability operation periods occurs very infrequently; with natural gas expected to become more available in future years, such an operating scenario will become less likely. However, while the reliability rules remain in place and commenter's boilers are required to operate under his regimen, the commenter believed that it is essential that it be able to do so.

Other commenters noted that requiring installation of emission controls on oil-fired units that operate at a 10 percent oil-fired capacity factor or less is nonsensical and will result in little environmental benefit. Commenters contend that low-capacity factor units emit significantly less HAP than even well-controlled oil-fired units with much higher capacity factors. In addition, commenters allege that stack-testing at such units would be equally impractical and, in addition, would likely require the unit to operate on oil (and emit HAP just for the test) when it would otherwise be off-line or operating on natural gas.

Response: As stated above, after considering comments received, we are establishing a limited-use subcategory for liquid oil-fired EGUs with an annual fired capacity factor of less than 8 percent averaged over each 24-month block period after the compliance date.

At proposal, we solicited comment on establishing a limited-use subcategory for liquid oil-fired EGUs:

> EPA is also considering a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil and are inoperative the remainder of the year. Such units could have specific emission limitations, reduced monitoring requirements (limited operation may preclude the ability to conduct stack testing), or be held to the same emission limitations (which could be met through fuel sampling) as other liquid oil-fired units. EPA solicits comment on all of these proposed subcategorization approaches.

As stated above, the EPA did not have sufficient information on limited-use liquid oil-fired EGUs upon which to base a subcategory at proposal. Some sources required to test under the ICR did not submit the data until after proposal. Commenters indicated that their units are different because many of them are only called to service to address reliability issues associated with, for example, natural gas curtailments. The commenters further indicated that their units are different because of the generally infrequent use and the sporadic, and at times frequent, start-up and shutdown periods (*e.g.,* they are often only required to run for a couple of hours). These factors would lead to differences in the emissions characteristics for these units such that a numeric standard based on base load units would not likely be achievable during the very limited times that these limited use oil-fired units operate.

Based on comments received and our own analysis, we are finalizing a subcategory for limited-use liquid oil-fired EGUs as indicated elsewhere in this preamble. We find that these units constitute a different class and type of units because they are generally only used to address reliability issues associated with, for example, natural gas curtailments, and because they in fact only run for very limited periods in a year on a seasonal basis.

Although some commenters indicated a prevalence of natural gas/oil co-fired EGUs, the EPA also understands that there are other liquid oil-fired EGUs that do not co-fire natural gas but that could be subject to mandatory operation during periods of natural gas curtailment in their operating area if sufficient non-natural gas capacity is not available. Based on a review of units that report oil use to EPA, in 2010 there were 228 liquid oil-fired EGUs with a capacity factor of less than 5 percent and an additional 10 units with a capacity factor of between 5 percent and 10 percent. Only 2 of these units have capacity factors between 5 percent and 8 percent. This subcategory applies only to oil-fired EGUs that operate on oil alone and act as peaking units, as they generally address reliability issues. We are establishing the capacity factor threshold of 8 percent averaged over each 24-month block period after the compliance date.[320] In addition, as discussed below, we are establishing work practice standard for this subcategory in lieu of numeric emission standards.

Commenters that requested a subcategory for these units noted the dichotomy of establishing a NESHAP to reduce emissions of HAP to the environment while at the same time requiring an EGU to run for the sole purpose of conducting emissions testing and thereby emitting those same HAP. Because the operation of these units is infrequent and unpredictable, performing testing to demonstrate that emission limits are being met requires the sources to be scheduled to be operated merely for the purpose of performing testing. We realize that similar situations occurred in the gathering of emissions data through the 2010 ICR. However, unlike the case of one-time testing on a limited number of these units, such testing would be mandatory on a yearly basis for all of the EGUs upon the effective date of the final rule. Because requiring testing under this rule would in many cases require operators of these EGUs to schedule operation of these EGUs at times they would not otherwise run, it would result in both extra cost related to the testing as well as extra emissions; therefore, the Agency believes that it is technically and economically impracticable to monitor emissions for these EGUs, and that they should be subject to work practice standards that would not require emissions monitoring.

The annual average capacity factor would be calculated on a 24-month block period, commencing with the compliance date of the final rule. For example, assuming a March 1, 2015, compliance date, the first 24-month block would commence on March 1, 2015, and end on February 28, 2017, with the next 24-month block averaging period commencing on March 1, 2017. We believe the 24-month averaging period is reasonable to account for the fact that units needed to address reliability issues (e.g., natural gas curtailment periods) will be called to service sporadically. A 24-month averaging period provides flexibility to ensure that these units can run if there are large periods when natural gas is unavailable. As explained above, the data shows that most of these units operate for less than 8 percent of the time, and in fact it is usually less than 5 percent. Therefore, when considering whether these units would be able to perform stack testing, in many cases this will be for units that in fact operate significantly less than 8 percent of the time. In these cases, the EPA does not want to require the units to operate more just for the purpose of running a stack test resulting in additional pollution and cost. With projections for rising oil prices relative to natural gas prices, we expect this trend to continue. Liquid oil-fired EGUs subject to this subcategory would be required to conduct the same initial and periodic tune-up as all other affected units, but would have no other emission limit or work practice requirements.

Although the EPA believes that the ability to burn oil up to 8 percent of the time should address concerns about units that may need to operate using oil during gas curtailments. The EPA recognizes that if there were a period where gas use was more severely limited, such units might need the flexibility to operate for more than 8 percent in one year and less in the next, which is why we are providing the 2-year period; however based on the data we do not think EGUs in this subcategory will exceed even the 5 percent capacity factor that the data indicate is the average level for these sources.

4. Non-Continental Units

Comment: Commenters from affected island EGUs requested that non-continental EGUs be subcategorized from continental EGUs based on their lack of access to natural gas. The commenters urged the EPA to include a ‘‘non-continental liquid oil’’ subcategory in the final rule. According to the commenters, establishing a subcategory for non-continental units is consistent with the approach the EPA has taken in past rulemakings, including the final Industrial Boiler NESHAP. Non-continental EGUs have little or no access to natural gas, minimal control over the quality of available fuel, and disproportionately high operational and maintenance costs. All oil-fired EGUs operating in Hawaii, Guam, and Puerto Rico combust residual fuel oil exclusively and all are limited by the crude slates of their fuel suppliers. Island utilities can contract with suppliers for certain fuel specifications, such as sulfur content, pour point, flash point, API gravity and viscosity, which the refiners are able to meet primarily by blending and some sulfur removal during the refining process. However, the commenters state that the suppliers do not and cannot economically control for metal content. The crude slate feeding the refinery determines the HAP metal content of the residual oil produced according to the commenters. Because island utilities are dependent on local sources of fuel, they are equally limited by these factors.

Two commenters believe that the separate non-continental subcategory should be expanded to include continental areas that are not interconnected with other utilities and have limited compliance options due to remote locations (*e.g.,* Alaska).

Response: The EPA agrees that the unique considerations faced by non-continental EGUs warrant a separate subcategory for these units and the data show that the difference in location causes a difference in emissions apparently due to the fuel that is available for such units; thus, the Agency has included such a subcategory in the final rule. At proposal, the EPA did not have all of the data from liquid oil-fired units in non-continental areas (*e.g.,* Guam, Puerto Rico) and solicited comment on whether a subcategory should be established, based on the data to be received, for non-continental oil-fired EGUs. The EPA has now received these late data and, based on those data, is finalizing a non-continental subcategory for liquid oil-fired EGUs in Guam, Hawaii, Puerto Rico, and the U.S. Virgin Islands. The EPA is not aware of

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[320] Units that co-fire oil and natural gas where the oil combustion comprises 10 percent or less of the capacity factor are natural gas-fired EGUs that are not subject to this final rule.

any liquid oil-fired EGUs in any of the other U.S. territories that meet the CAA section 112(a)(8) definition but, if there are such units, they would also be part of the non-continental subcategory.

The EPA agrees that the unique considerations faced by non-continental refineries, including a limited ability to obtain alternative fuels that lead to different emissions characteristics, warrant a separate subcategory for these EGUs. The EPA believes that units in this subcategory will comply through the use of cleaner oils or, for PM, through the installation of an ESP. The EPA finds no merit in the comment that Alaska should be included in this non-continental subcategory because utilities in Alaska are not faced with the same access issues affecting island-based facilities.

C. Surrogacy

1. Filterable PM vs. Total PM

Comment: Numerous commenters strongly objected to the use of total PM as the surrogate standard for non-mercury HAP metals. They argued that filterable PM is a better surrogate, especially given EPA's intent to use a PM CEMS for continuous compliance demonstration. Other commenters argued that we should not use a surrogate and instead should require direct compliance with a non-mercury HAP metals standard.

Response: We have decided to use a filterable PM limit for the PM surrogate emission limit in the final rule.

Although the objective of the emission limits we are establishing is to reduce the risks associated with HAP emissions, the limits are based in part upon the demonstrated capabilities of control technologies which are installed on existing sources. Except for Hg, the best PM controls provide the best controls of metal emissions. Emissions measurements of either filterable particulate, total particulate, individual metals, or total metals provide comparable indications that the best level of control is achieved. We can find no significant difference in the emissions that would be achieved by using any one of these emissions measurements.

We re-assessed the relationships between individual metal emissions, filterable PM emissions, total PM emissions, and total $PM_{2.5}$ emissions based on the test results provided through part III of the 2010 ICR. We compared the measured emissions of metals and PM with the uncontrolled emissions estimates and found that control of PM was indicative of the control of metals emissions. In addition, we compared the correlations associated with non-mercury HAP metal emissions and the three forms of PM and found that no specific particulate form provided a consistently superior indicator of better metals control. Although control of filterable PM provided the best indicator of performance for control of some HAP metals, control of total particulate or total $PM_{2.5}$ was nearly as good as an indicator. For control of other HAP metals, total PM measurement provided the best indicator of control performance because it included the vapor-phase metal HAP, although, measurement of the control of filterable particulate was nearly as good an indicator. In addition, certain data analyzed by our Office of Research and Development indicate that a vapor-phase metal, such as Se, can be present as an acid gas and reduced significantly using acid gas technologies (wet and dry scrubbing). Given that the rule also provides for acid gas control monitoring, and the general equivalency of the different indicators, we have concluded that use of a filterable PM limit as the PM surrogate emission limit is appropriate.

2. Moisture Content of Oil

Comment: A number of commenters stated that studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils and then be emitted as HCl during combustion. For example, the commenters asserted that the chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double hulled and establishes a phase out schedule (by the middle of the decade) for existing single hulled tankers with un-segregated ballasts. Because of the role of seawater contamination in introducing contaminants into the oil, the commenters suggest that the EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. One commenter recommended a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

Response: The EPA is providing the alternative compliance assurance approaches in the final rule for liquid oil-fired EGUs of demonstrating compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

The EPA is not aware of any FGD systems installed on oil-fired EGUs. Thus, it is only the quality of the oil, and the level of HAP constituents contained therein, that can be relied upon for ensuring compliance.

In the proposal preamble, we stated:

> We believe that chlorine may not be a compound generally expected to be present in oil. The ICR data that we have received suggests that in at least some oil, it is in fact present. EPA requests comment on whether chlorine would be expected to be a contaminant in oil and if not, why it is appearing in the ICR data. To the extent it would not be expected, we are taking comment on the appropriateness of an HCl limit. *See* 76 FR 25045.

Commenters refer to certain studies that provide a plausible reason for the chloride/fluoride contamination of fuel oils. We found this reason persuasive and accordingly are providing alternative compliance approaches in the final rule to demonstrate compliance with the acid gas HAP standards. Specifically, sources can demonstrate compliance through either specific HCl or HF measurements or by demonstrating that the moisture content in the fuel oil remains at a level no more than 1.0 percent.

D. Area Sources

Comment: Numerous comments were received both in support of and in opposition to the establishment of generally available control technology (GACT) standards for area source EGUs.

Several commenters in opposition to area source standards stated that the EPA properly established emissions limitations based upon the performance of all EGUs, rather than distinguishing between major sources and area sources. The commenters believe that Congress did not intend the EPA to distinguish between ''major source'' EGUs and ''area source'' EGUs in determining whether and how to regulate EGUs under CAA section 112. These commenters indicated that differentiating major source and area source EGUs for purposes of setting emissions standards is inappropriate in light of the 2000 Finding regarding the threat posed by the absence of regulation of HAP emissions from EGUs. The 2000 Finding was based upon studies whose conclusions regarding the impacts from EGU emissions did not depend upon any relevant distinction between major source and area source EGUs. The commenters note that segregating ''major source'' and ''area source'' EGUs would have the perverse effect of eliminating some of the best performing sources from the MACT pool of sources that constitute the ''best performing'' 12 percent. Many of the best performing sources have employed control technology that brings their emissions below the major source threshold, despite the fact that they are larger units. As a result, the commenters believe that if the EPA created standards for ''major source'' EGUs based only upon those units, the MACT standards for ''major source'' EGUs would be less stringent for each of the pollutants than proposed in this Rule. At the same time, the less polluting sources, the ''area source'' EGUs, could face limits more stringent than those proposed in the Rule. Commenters also note that after reviewing the substantial record in this rulemaking, they believe that the EPA has correctly determined that major and area source EGUs greater than 25 MW have similar HAP emissions and use the same control technologies and techniques to reduce HAP emissions. Thus, the commenters asserted that the record demonstrates that there is no technical basis for distinguishing between major and area source EGUs for purposes of establishing HAP emission control standards under CAA section 112(d).

Many commenters in support of an area source designation for EGUs stated that the EPA has promulgated area source limits for many source categories of HAP emissions, including most recently industrial boilers and note that GACT controls have been used successfully in many other EPA MACT rules, including rules for iron & steel foundries, electric arc steelmaking, coatings operations, clay ceramics manufacturing, glass manufacturing, and secondary nonferrous metals manufacturing, in order to reduce costs and regulatory burdens. The commenters state that Congress has given the EPA the ability to subcategorize area sources because of their low HAP emissions and low potential impact on human health and that, contrary to the plain language of CAA section 112 and its legislative history, the EPA made no attempt in the proposed rule to distinguish between major sources and area sources for purposes of listing or setting standards. The commenters indicated that where Congress was concerned about the health impacts of specific pollutants from specific sources, it knew how to specify that MACT limits be promulgated (*e.g.,* CAA section 112(c)(6)). The commenters state that area source rules would lessen the regulatory burden of a CAA section 112 EGU rule on many small entities (arguing that many EGUs owned by small public power entities are area sources) and that as many as 12 percent of the EGU population could qualify as area sources. A number of commenters pointed out that the small entity representatives (SER) on the SBREFA panel suggested that the EPA establish separate emission standards for EGUs located at area sources of HAP and that the standards be based on GACT as allowed under CAA section 112(d)(5). Specifically, the SERs recommended that the EPA establish management practice standards for area source EGUs.

Response: The EPA is not establishing an area vs. major source distinction in the final rule.

The CAA section 112(a)(8) definition of EGU does not distinguish between major and area sources, and we maintain that EGUs are a single source category that contains both major and area sources. The EPA proposed to regulate five subcategories of EGUs without distinguishing between major and area sources for purposes of establishing the standards for the different subcategories. Our approach is wholly consistent with the statutory definition of EGU and reasonable.

Nevertheless, the Agency did examine whether to set separate standards for area source EGUs, because we do not believe that the statute prohibits the Agency from exercising its discretion to establish GACT standards for area sources pursuant to CAA section 112(d)(5) if we determine such standards are appropriate. The EPA is not required, however, to establish GACT standards for area sources, and we believe it may even be unreasonable to do so under the circumstances we identified in the proposed rule as supported by the record of this final rule.

At proposal, we determined that it was not appropriate to establish separate standards for major and area source EGUs, and even if we had exercised our discretion to set separate standards, we would have likely declined to exercise our discretion to set GACT standards for area source EGUs given our appropriate and necessary finding and the fact that a potentially large number of area source EGUs are in fact large well controlled units.

Some commenters note that there could be as many as 12 percent of the total population that could be classified as area sources. We are not sure of the commenters' point in regard to this statement. As to commenters' statements that many of the area sources are municipal utilities, our information shows that many rather large EGUs (*e.g.,* hundreds of MW) are also area sources, and the commenters have not provided any justification for establishing GACT standards for large synthetic area sources.

Commenters did not provide an evaluation of the health and environmental impacts of the area sources and simply presume that the risks from such sources are lower, even though many of the same commenters noted that these smaller EGUs are often located in densely populated areas where populations are more likely to have adverse health effects from the HAP emissions. Furthermore, other commenters, including some industry commenters, noted that the vast majority of these potential area sources meet the criteria due to the installation of emission controls installed to meet other requirements. According to these commenters, these synthetic area sources would likely be able to meet the limits of this rulemaking and imposition of this rule would not appear to result in the installation of additional controls in a number of cases. We do not know if this assertion is correct but we determined approximately 69 coal-fired EGUs will be able to meet the existing source MACT standards with their current control configuration (out of 252 EGUs that reported data for Hg, PM, and HCl in the 2010 ICR).

Commenters also note that the Agency has exercised its discretion in other NESHAP rulemakings to establish area source limits. Although true, the fact that the EPA has established area source limits in some source categories is irrelevant to similar decisions for different source categories. Commenters have not shown that the circumstances applicable to those other source categories are similar to the circumstances identified for major and area source EGUs (*e.g.,* similar controls, similar emission characteristics, large number of synthetic minor area sources). Further, those other source categories are not statutorily defined in a manner that includes both area and major sources. EGUs are the only source category defined in CAA section 112 and, in establishing the definition of an ''electric utility steam generating unit'' under CAA section 112(a)(8), Congress included in the EGU source category both area and major sources. Thus, it is reasonable to regulate the EGU category in the manner Congress defined the category. Commenters have provided no legal support for the contention that the EPA must regulate area and major sources in the same category in separate rulemakings, and the EPA has in fact regulated both major and area sources in the same rulemaking even absent a statutory definition that includes both major and area sources. (*See* National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants; 75 FR 54970; September 9, 2010.)

The EPA considered the totality of the circumstances when determining whether to set separate area and major source standards for EGUs and also considered whether it would be reasonable to establish GACT standards for areas sources. We reasonably considered whether emissions characteristics of major and area sources are different when determining whether to establish GACT standards, notwithstanding commenters' assertion that such consideration is not correct. That we also consider emission characteristics in subcategorization decisions is of no consequence for area source decisions. Given that the statutory definition of EGUs contains both major and area sources, it was reasonable to evaluate whether there were sufficient differences between area and major sources when deciding whether to exercise our discretion to set separate area and major source standards.

In addition, we find commenter's point concerning CAA section 112(c)(6) odd because EGUs emit several of the CAA section 112(c)(6) HAP (*e.g.,* lead, Hg). Although EGUs were exempted from that provision, the fact that they emit some of the HAP called out for MACT control supports our decision to not establish GACT standards for any EGUs. CAA section 112(d)(5) leaves it to the Agency's discretion to determine whether GACT standards should be established for area sources, and the statute does not require GACT standards or even indicate that such standards are to be the default regulatory approach for area sources. *See* 76 FR 25021. Instead, the statute provides the Agency with discretion and we have exercised it reasonably in this case.

Commenters indicate that many EGUs owned by small entities are potential area sources. However, commenters fail to note that there are also EGUs owned by small entities that are not potential area sources, and, thus, would not accrue any ''lessened regulatory burden'' benefit from a decision by the EPA to establish area source standards.

Some commenters state that the EPA's mere assertion that there would be no difference between GACT and MACT to justify an area source finding does not provide sufficient documentation for the decision. But EPA did not say there would be no difference between MACT and GACT. Instead, it stated that it would be difficult to make a distinction given the similarities between the EGUs and major and area source facilities. Specifically, as noted by other commenters, and observable by a review of the MACT Floor Analysis spreadsheets, potential area sources range in size from units near the CAA section 112(a)(8) defined lower size limit to units of hundreds of megawatts. Further, these larger area source units are, for the most part, controlled with the full suite of emission control technologies available (*e.g.,* fabric filters, scrubbers).

In addition, the data that were available in the docket for the proposed rule show that there is little difference between major and area source EGUs individually, and that generally the driver for whether a utility facility is a major or area source depends on the number of EGUs located at a facility (almost exclusively one or two EGUs located at area sources), not on any inherent difference between the EGUs themselves. *See* ''Evaluation of Area Source EGUs'' TSD, Docket EPA–HQ–OAR–2009–0234. In fact there are a number of EGUs that are quite large that are area sources and others that are small that are major sources. *Id.* This is the case because the acid gas HAP emissions are what drive EGUs to have HAP emissions exceeding the major source threshold. With a few exceptions, the EGUs located at area sources have FGD or other acid gas controls that reduce the acid gas HAP to area source levels. *Id.* Thus, the majority of sources that currently qualify as area sources were, in fact, major sources prior to installing controls. The exceptions are those units that would likely be able to achieve the MACT level of control for acid gas with minimal use of DSI at a reasonable cost. *Id.*

In addition, the data show that a number of area sources for which we have data are high emitters of Hg and non-Hg metal HAP. *Id.* Pursuant to our appropriate and necessary finding, these HAP pose a significant threat to human health. Thus, even were we to distinguish between major and area sources, which we do not believe is appropriate given the similarities between such sources, we would still decline to set GACT standards, and as such we maintain that MACT standards are appropriate. Moreover, for acid gas HAP, as discussed above, the data indicate that the level of control would likely be the same even if we did establish GACT standards under CAA section 112(d)(5).

We fully evaluated the nature of EGUs, and we do not see a basis on which to distinguish these sources for purposes of setting standards. Thus, we maintain that we reasonably exercised the discretion afforded the Agency under the statute and declined to set separate standards for area source EGUs.

E. Health-Based Emission Limits

Comment: Many commenters noted that in the proposed rule the EPA considered whether it was appropriate to exercise its discretionary authority to establish health-based emission limits (HBEL) under CAA section 112(d)(4) for HCl and other acid gases and proposed not to adopt such limits, citing, among other things, information gaps regarding facility-specific emissions of acid gases, co-located sources of acid gases and their cumulative impacts, potential environmental impacts of acid gases, and the significant co-benefits estimated from the adoption of the conventional MACT standard. Comments were received both supporting this position and refuting it. Several commenters suggested legal, regulatory and scientific reasons for why HBEL for HCl might be appropriate for this MACT standard. With respect to legal concerns, some commenters indicated that CAA section 112(d)(4) establishes a mechanism for the EPA to exclude facilities from certain pollution control regulations and circumstances when these facilities can demonstrate that emissions do not pose a health risk. Commenters cited a Senate Report that influenced development of CAA section 112(d)(4), where Congress recognized that, ''For some pollutants a MACT emissions limitation may be far more stringent than is necessary to protect public health and the environment.'' (Footnote: S. Rep. No. 101–128 (1990) at 171.) Commenters also cited regulatory precedent for addressing HCl as a threshold pollutant, including the Hazardous Waste Combustors and the Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills NESHAP. Commenters requested that the EPA incorporate the flexibility afforded by CAA section 112(d)(4) and allow sources reasonable means for demonstrating that their respective emissions do not warrant further control. The commenters also cited the 2004 vacated Boiler MACT as precedent for HBEL for HCl. The commenters contended that the EPA failed to explain why the health-based emissions limitations it established in the 2004 Boiler MACT and the justification provided for those limitations could not be used in this case. The commenters also cited a 2006 court briefing where the EPA vigorously defended the HBEL included in the 2004 Boiler rule when it was challenged in the D.C. Circuit (Final Brief For Respondent U.S. Environmental Protection Agency, D.C. Cir. Case No. 04–1385 (Dec. 4, 2006) at 59–65, 69).

Other commenters stated that on August 6, 2010, the EPA adopted a NESHAP for Portland Cement plants that specifically rejected adoption of risk-based exemptions or HBEL for HCl and manganese (Mn). These commenters argue there are no differences sufficient to warrant a reversal of that decision in the EGU MACT standard. The commenters raised concerns that health risk information cited by the EPA for HCl, HF, and hydrogen cyanide (HCN) does not establish ''an ample margin of safety'' and, therefore, no health threshold should be established. The commenters believe risk-based exemptions at levels less stringent than the MACT floor are prone to lawsuits that could potentially further delay implementation of the EGU MACT.

Some commenters disagreed with using a hazard quotient (HQ) approach to establish a risk-based standard because the HQ would not account for potential toxicological interactions. The commenter noted that an HQ approach incorrectly assumes the different acid gases affect health through the same health endpoint, rather than assuming that the gases interact in an additive fashion. This commenter suggested that a hazard index approach, as described in the EPA's ''Guideline for the Health Risk Assessment of Chemical Mixtures,'' would be more appropriate.

Some commenters dispute that emissions from other EGUs or source categories should be considered when developing an HBEL and they argued that Congress expected the EPA to consider the effect of co-located facilities during the CAA section 112(f) residual risk program instead of under CAA section 112(d). Commenters added that there is no prior EPA precedent for considering co-located facilities from a different source category during the same CAA section 112 rulemaking.

Several commenters disputed the EPA's consideration of non-HAP collateral emissions reductions in setting MACT standards. They contended that the EPA's sole support for its ''collateral benefits'' theory is legislative history—the Senate Report that accompanied Senate Bill 1630 in 1989 and noted that the D.C. Circuit rejected this use of this theory since the Senate Report referred to an earlier version of the statute that was ultimately not enacted. Instead commenters suggested that other components of the CAA, such as the National Ambient Air Quality Standards (NAAQS), are more appropriate avenues for mitigating emissions of criteria pollutants.

Several other commenters suggested it is impossible to assess an established health threshold for HCl such that a CAA section 112(d)(4) standard could be set without evaluating the collateral benefits of a MACT standard. And, as described in the recently finalized cement kiln MACT rule, setting technology-based standards for HCl will result in significant reductions in the emissions of other pollutants, including SO_2, Hg, and PM. The commenter added that these reductions will provide enormous health and environmental benefits, which would not be experienced if CAA section 112(d)(4) standards had been finalized. These commenters contended that HCl and other dangerous acid gases produced by EGUs pose substantial risks to industrial workers, as well as surrounding communities, and must be limited by the strict conventional MACT standards.

Several commenters indicated that the current economic climate requires the EPA to balance economic and environmental interests and indicated that HBEL would help target investments into solving true health threats where limits are no more or less stringent than needed to protect public health. Many commenters provided estimates of compliance cost savings if an HBEL is included in this final rule. Some commenters stressed the importance of an HBEL for small entities affected by the regulations. Several other commenters suggested that the EPA should estimate the costs and environmental effects of the HBEL option compared to a conventional MACT standard in order to make an informed decision on the adoption of HBEL.

Response: After considering the comments received, the EPA has decided not to adopt an emissions standard based on its authority under CAA section 112(d)(4) for all the reasons set forth in the proposed rule.

The EPA notes that the Agency's authority under CAA section 112(d)(4) is discretionary. That provision states that the EPA ''may'' consider establishing health thresholds when setting emissions standards under CAA section 112(d). By the use of the term ''may,'' Congress clearly intended to allow the EPA to decide not to consider a health threshold even for pollutants which have an established threshold. As explained in the preamble to the proposed rule, it is appropriate for the EPA to consider relevant factors when deciding whether to exercise its discretion under CAA section 112(d)(4), and, notwithstanding commenters' assertions to the contrary, the considerations we include in our analysis are reasonable. The EPA has considered the public comments received and is not adopting an emissions standard under CAA section 112(d)(4) for the reasons set forth in the proposed rule and explained below. We note that this action is consistent with EPA's recent decisions not to develop standards under CAA section 112(d)(4) for the Industrial, Commercial and Institutional Boilers and Process Heaters and the Portland Cement source categories.

As explained in the preamble to the proposed rule, the EPA continues to believe that the potential cumulative public health and environmental effects of all acid gas HAP emissions, not just HCl emissions, from EGUs and other acid gas sources located near EGUs supports the Agency's decision not to exercise its discretion under CAA section 112(d)(4). Additional data for all acid gas emissions were not provided during the comment period, and the data already in hand regarding these emissions are not sufficient to support the development of emissions standards for EGUs under CAA section 112(d) that take into account the health threshold for acid gas HAP, particularly given that the Act requires the EPA's consideration of health thresholds under CAA section 112(d)(4) to protect public health with an ample margin of safety. We note here that EPA agrees with the commenter who pointed out that a better way to evaluate the potential health impact interactions of all acid gases would be to use the approach in EPA's ''Guideline for the Health Risk Assessment of Chemical Mixtures'' rather than a simple evaluation of individual HQ values for each acid gas, but we further note that use of such an approach requires a substantially greater knowledge of acid gas emissions than is currently available. We further note that, even if cost were a relevant factor in setting standards under CAA section 112(d)(4), since the data are not available that would allow us to develop an acid gas HBEL appropriate to protect public health with an ample margin of safety, we cannot determine whether such standards would have any cost savings associated with them or not. In addition, the concerns expressed by the EPA in the proposal regarding the potential environmental impacts and the cumulative impacts of acid gases on public health were not assuaged by the comments received because no significant data regarding these impacts were received.

The EPA also received comments recommending not only that the EPA establish emissions standards for acid gases pursuant to CAA section 112(d)(4), but that it do so by excluding specific facilities from complying with emissions limits if the facility demonstrates that its emissions do not pose a health risk. The EPA does not believe that a plain reading of the statute supports the establishment of such an approach. Although CAA section 112(d)(4) authorizes the EPA to consider the level of the health threshold for pollutants which have an established threshold, that threshold may be considered ''when establishing emissions standards under [CAA section 112(d)].'' Therefore, the EPA must still establish emissions standards under CAA section 112(d) even if it chooses to exercise its discretion to consider an established health threshold. A source-by-source standard is not mandated as some commenters seem to imply, and we are unsure how we could reasonably implement such an approach even if we determined such an approach was legally available. For these reasons alone, we concluded it was not appropriate to exercise our discretion to establish section 112(d)(4) standards for acid gas HAP emissions.

In addition, as explained in the preamble to the proposed rule, the EPA also considered the co-benefits of setting a conventional MACT standard for HCl. The EPA considered the comments received on this issue and continues to believe that the estimated co-benefits are significant and provide an additional basis for the Administrator to conclude that it is not appropriate to exercise her discretion under CAA section 112(d)(4). The EPA disagrees with the commenters who stated that it is not appropriate to consider non-HAP benefits in deciding whether to invoke CAA section 112(d)(4). Although MACT standards may directly regulate only HAP and not criteria pollutants, Congress did recognize, in the legislative history to CAA section 112(d)(4), that MACT standards would have the collateral benefit of controlling criteria pollutants as well and viewed this as an important benefit of the air toxics program. *See* S. Rep. No. 101–228, 101st Cong. 1st sess. at 172. The EPA consequently does not accept the argument that it cannot consider reductions of criteria pollutants in determining whether to take or not take certain discretionary actions, such as whether to adopt an HBEL under CAA section 112(d)(4). There appears to be no valid reason that, in situations where the EPA has discretion in what type of standard to adopt, the EPA must ignore controls which further the health and environmental outcomes at which CAA section 112(d) is fundamentally aimed because such controls not only reduce HAP emissions but emissions of other air pollutants as well. Thus, the issue being addressed is not whether to regulate non-HAP under CAA section 112(d) or whether to consider other air quality benefits in setting CAA section 112(d)(2) standards—neither of which the EPA is doing—but rather whether EPA may exercise its discretion to regulate certain HAP based on the MACT approach and consider collateral health and environmental benefits when choosing whether to exercise that discretion. The EPA believes there is no legal principle that precludes it from doing so and commenters have not provided one.

F. Compliance Date and Reliability Issues

Comment: Multiple commenters asked that the compliance date be clearly stated as soon as possible, as well as that guidance be provided for utilities unable to comply with the stated timelines, to allow time for utilities to prepare for compliance. Commenters also asked that any decisions or policies on extensions be published in a rulemaking. In addition, commenters requested that the EPA establish, streamline, and simplify the process of applying for the 1-year extension under CAA section 112(i)(3).

Multiple commenters offered suggestions on methods for allowing more time for compliance, including EPA's authority under CAA section 112(n)(1)(A); state authority under CAA section 112(i)(3); Presidential authority under CAA section 112(i)(4); categorical extensions for publicly-owned or governmental facilities according to EO 13132, 13563, and UMRA of 1995; state-designed programs under the delegation provisions of CAA section 112; various Consent Decrees; Administrative Orders of Consent (AOCs); temporary waiver mechanisms; and adoption of MACT compliance schedules through minor permit modifications of a source's Title V federal operating permits. Absent such considerations for additional compliance time, many commenters suggested that the reliability of the nation's electric grid would be jeopardized as utility companies were forced to retire EGUs because they could not install the needed controls in the requisite time.

Compliance times requested by commenters ranged from 1 additional year (4 years total) to 6 additional years (9 years total). Multiple commenters requested that a utility be required to demonstrate good faith progress toward compliance to get any extension. Some commenters suggested that the EPA require utilities to submit a notice concerning which EGUs will be retrofitted or retired within 1 year of the effective date; that the compliance date align with the Power Year used by RTOs; and that the EPA clarify that retirement and any clean replacement power that complies with the NESHAP rule, including off-site combined heat and power and waste heat recovery, can be deemed ''controls'' under the CAA.

Commenters noted the specific situations related to small entities and their inability to compete with the larger, investor-owned utilities for financing and engineering and technical labor as well as the different process they need to follow for capital improvements. Multiple commenters asked that the EPA consider other simultaneous rulemakings (*e.g.,* Cooling Water Intake Structures; Coal Combustion Residuals; CSAPR, etc.) and extend the compliance period. Many commenters noted these other requirements and suggested that installation of the necessary controls could not be completed within the compliance period allowed under CAA section 112, even if a fourth year were to be granted by the permitting authority, citing examples of the times necessary for installation of various pieces of control equipment or replacement power.

Some commenters pointed to existing state programs (*e.g.,* Colorado, Oregon, Washington) and indicated that if states can demonstrate that overall emissions reductions would be equivalent or greater than those that would be achieved by the proposed rule, the EPA should delegate the CAA section 112 program to these states, even if the state emissions reductions would not necessarily occur on the same schedule (many state programs call for retirement of EGUs in years beyond the CAA section 112 compliance date). The commenters did not want the promulgation of the final rule to undermine the significant amount of work that may have been invested in creating state-specific programs to curb emissions within a reasonable timeframe. The commenters seek to make use of temporal flexibility, authorized under CAA section 112(i)(3), in obtaining delegation of the final rule to preserve the hard-negotiated comprehensive state-specific programs designed to yield greater emission reductions than the MATS alone.

Other commenters requested that no additional time be granted for compliance. These commenters reference a number of reports (*e.g.,* by the URS Corporation, by M.J. Bradley & Associates and the Analysis Group, and by the Bipartisan Policy Center) to indicate that not only is technology readily available, but that the technology can typically be installed in less than 2 years and that the electric industry is well-positioned to comply with the EPA's proposed air regulations without threatening electric system reliability. Commenters assert that, if electric system reliability were to be threatened in local areas as a result of the rule, the EPA has the statutory authority to grant, on a case-by-case basis, extensions of time to complete the installation of pollution control systems. One commenter stated that no additional controls would need to be installed in many cases and any coal unit should be able to comply with all of the standards. Another commenter noted that utilities that failed to plan ahead ''should not be permitted to use their own inaction to justify more time.'' Commenters noted that several major utility companies have anticipated the EPA's rules and are already taking action to ensure a reliable supply of electricity in their service territory and beyond. Other commenters agree that there is significant excess generation capacity in the country and reliability will not be threatened by the rule. According to one commenter, companies are already preparing for a 2015 compliance date, factoring in the capital expenditures required to comply and delays would undermine decisions that have already been made. Commenters cite, for example, recent electricity forward capacity market auctions in the PJM market for the period of 2014 and 2015 that indicate that the capacity markets cleared with electricity reserve margins of 20 percent; this is in excess of the default reliability targets used by the North American Electric Reliability Corporation (NERC) for the year 2015. One commenter quoted NERC, stating that NERC does not see impacts from proposed climate legislation or anticipated EPA regulation as a reliability concern. Another commenter noted that the Building and Construction Division of the AFL–CIO has stated that there is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology installation. In fact, according to the commenter, given the high levels of unemployment in the construction sector, these jobs are much needed.

A number of commenters expressed concern that the time frame for compliance with a regulation under CAA section 112(d) was too short for this industry and would result in compromising the reliability of electricity supply. Commenters asserted that reliability would be compromised in several ways: (1) EGUs might have to temporarily close if the owner or operator is unable to install controls on the unit within the 3-year time frame or 3 years plus one; (2) the timing of outages to install controls will cause short term closures that could threaten grid stability; (3) owner/operators may shut down EGUs rather than invest in retrofits to keep them running and that these closures may cause a loss of critical generation; and (4) the construction of replacement generation or implementation of other measures to address reliability concerns due to plant retirements could take longer than 3 years, and that units slated for closure may be necessary beyond the 3-year compliance period but will be unable to run because they have not installed the necessary controls.

Response: Clean Air Act section 112 specifies the dates by which affected sources must comply with this rule. New or reconstructed units must be in compliance immediately upon startup or the effective date of this rule, whichever is later. Existing sources may be provided up to 3 years after the effective date to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the ability to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls.

As is explained earlier in this preamble, the 3-year compliance window is based on the date that is 60 days after publication of this rule in the **Federal Register**. Because publication doesn't occur until several weeks after the rule is signed by the Administrator, the earliest required date for compliance would be sometime in March 2015. Because the last stage of control installations usually needs to occur when the unit is off-line and because scheduled outages are usually scheduled for the spring or fall months when peak electric demand is lower, this additional time is significant as it provides companies an additional outage period, the spring of 2015, to install controls.

The EPA has considered the concerns raised by commenters and has concluded that given the flexibilities further detailed in this section, the requirements of the final rule for existing sources can be met by most sources without adversely impacting electric reliability. In particular, EPA believes that the flexibility of permitting authorities to allow a fourth year for compliance should be available in a broad range of situations (as discussed below), and that this flexibility addresses many of the concerns that have been raised. Furthermore as indicated below, 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.

The EPA considered the impact that potential retirements in response to this rule will have on resource adequacy in order to gauge the rule's impact on reliability. In considering these impacts, the EPA considered both the analysis it has conducted as well as analyses conducted by a number of other groups. The EPA's analysis shows that the expected retirements of coal-fueled units as a result of this final rule (4.7 GW) are fewer than was estimated at proposal and much fewer than some have predicted.[321] The net capacity reductions projected by the EPA make up less than one-half of one percent of the total generating capacity in the U.S. and about one and one-half percent of U.S. coal capacity. Because concerns have been raised that the use of DSI may not be as prevalent as the Agency has predicted and because this could lead to more coal retirements, the Agency also performed a sensitivity analysis in which fewer DSI systems and more scrubber systems were installed. In that sensitivity, we see approximately 1 more GW of retirements. This small change would have only a very small potential impact on resource adequacy. When considering the impact that one specific action has on power plant retirements, it is important to understand that the economics that drive retirements are based on multiple factors including: expected demand for electricity, the cost of alternative generation, and the cost of continuing to generate using an existing unit. The EPA's analysis shows that the lower cost of alternative fuels, particularly natural gas, as well as reductions in demand, will have a greater impact on the

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[321] The EPA's analysis also identifies a small amount of capacity loss (less than 0.7 GW) due to derating of certain units, as well as partially offsetting reductions in non-coal retirements in comparison with the base case. The net estimated reduction in capacity, in comparison with the base case, is estimated at less than 5 GW.

number of projected retirements than will the impact of this final rule.

The EPA's assessment looked at the capacity reserve margins in each of 32 subregions in the continental U.S. Demand forecasts used were based on EIA projected demand growth. The analysis shows that with the addition of very little new capacity, average reserve margins are significantly higher than required. The NERC assumes a default reserve margin of 15 percent while the average capacity margin seen after implementation of the policy is nearly 25 percent. Although such an analysis does not address the potential for more localized reliability concerns associated with transmission constraints or the provision of location-specific ancillary services (such as voltage support and black start service), the number of retirements projected suggests that the magnitude of any local reliability concerns should be manageable with existing tools and processes.

Several outside analyses have reached conclusions consistent with EPA's analysis. The DOE, in December 2011, published a report that looked at resource adequacy in the bulk power system when faced with a stress test which was a regulatory scenario far more stringent than EPA's regulations.[322] For this stress test, in addition to CSAPR and MATS requirements, each uncontrolled electric generator is required to install both a wet FGD system and a fabric filter to reduce air toxics emissions. If such installations are not economically justified, this scenario assumes that the plant must retire by 2015. In reality, as discussed previously, power plant owners will have multiple other technology options to comply with the regulations—options that typically cost less than installations of FGDs and fabric filters. The analysis finds that target reserve margins can be met in all regions, even under these stringent assumptions. Moreover, in every region but one (TRE), no additional new capacity is needed. In TRE, the analysis finds that less than 1 GW of new natural gas capacity would be needed by 2015 beyond the additions already projected to occur in the Reference Case. This analysis also finds that the total amount of new capacity that would be added by 2015 is less than the amount that is already under development.

In June 2011, the Bipartisan Policy Center issued a report analyzing potential collective impacts of EPA's pending power sector rules and concluding that ''scenarios in which electric system reliability is broadly affected are unlikely to occur.'' [323]

In August 2011, PJM Interconnection—the Regional Transmission Operator (RTO) responsible for planning and reliable operation of the bulk power system serving all or portions of 13 states in the Mid-Atlantic and Midwestern regions—issued a report analyzing the impacts of the CSAPR and the proposed MATS rule.[324] Although PJM's analysis assumes substantially more retirements than EPA projects, it nevertheless concludes that resource adequacy is not threatened in the PJM region. This is particularly significant, given that the PJM region is one of the largest and most heavily dependent on coal-fueled generation in the country. The PJM analysis notes, as EPA has acknowledged, that even where there is adequate generation capacity on a regional basis, localized reliability issues may emerge in connection with retirements that may need to be addressed.

The EPA has reviewed industry and NERC studies suggesting, contrary to the EPA's and these other groups' analyses, that EPA rules affecting the power sector (including this final rule, the CSAPR, EPA's proposed rule addressing power plant cooling water intake systems under section 316(b) of the Clean Water Act (CWA), and EPA's proposed rule addressing coal combustion residuals under the Resource Conservation and Recovery Act) will result in substantial power plant retirements. Some of these studies predict that such levels of retirements will have adverse effects on electric reliability in some regions of the country. Although the specifics of these analyses differ, in general they share a number of serious flaws in common that call their conclusions into question.

First, most of these studies make assumptions about the requirements of the EPA rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals or final rules. For example, a large proportion of the retirements projected by several of these studies is attributable to their inaccurate assumption that EPA's cooling water intake rule under CWA section 316(b) would require all or virtually all existing power plants to install cooling towers. In one study, the reliability effects reported are based on inaccurate assumptions that all existing EGUs with a capacity utilization factor of less than 35 percent would close, and that all in-scope electric generators would be required to install cooling towers within 5 years, whereas the not-selected options with closed cycle cooling in EPA's proposal envisioned that permit authorities could exercise discretion to allow facilities 10 to 15 years' time to comply. In most cases, these analyses were performed before the CWA section 316(b) rule or the MATS rule were even proposed; even analyses subsequent to the CWA section 316(b) proposal continue to inaccurately portray EPA's proposed approach.

Second, in reporting the number of retirements, many analyses fail to differentiate between plant retirements attributable to the EPA rules and retirements of older, smaller, and less efficient plants that are already scheduled for retirement because owners have made business decisions, based in significant part on market conditions, not to continue operating them.

Third, most of these analyses fail to account for the broad range of responses available to address electric reliability concerns associated with power plant retirements, including upgrades to the transmission system, construction of new generation, and implementation of demand-side measures. These measures are discussed at greater length below.

As a preliminary matter, none of these situations, either alone or in combination, will necessarily lead to an electric reliability problem. There is excess generating capacity in the U.S. today and in most cases an EGU that closes, either temporarily until it comes into compliance or permanently, will not cause a reliability problem. As explained above, our modeling of the impact of this final rule at the regional level projects retirements of less than one percent of nationwide generating capacity and confirms that there will continue to be adequate capacity in all 32 subregions of the country as sources comply with the rule.[325] This analysis shows that significantly less capacity will close in response to the final rule than might have under the proposal. Moreover, the regional modeling of retirements demonstrates that plants that close in response to this rule are spread out across the country rather than clustered in one area.

Outside analyses have identified many of the same flaws in studies

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[322] U.S. Department of Energy, December 2011, ''Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations.''

[323] Bipartisan Policy Center, June 2011, ''Environmental Regulation and Electric System Reliability.''

[324] PJM Interconnection, August 26, 2011, '' Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants.''

[325] *See* Technical Support Document on Resource Adequacy in this Docket.

projecting large-scale retirements as a result of EPA's power sector rules. For example, on August 8, 2011, the Congressional Research Service (CRS)[326] issued a report concluded that studies that assert that EPA rules will cause reliability problems, often make assumptions about the requirements of the rules that are inconsistent with, and dramatically more expensive than, the EPA's actual proposals. The CRS further noted that EPA's rules will primarily affect units that are more than 40-years old, that have not yet installed state-of-the-art pollution controls, and that are inefficient. Many of these plants are being replaced by combined cycle natural gas plants, driven more my lower gas prices than by EPA's regulations. The June 2011 Bipartisan Policy Center report referenced above likewise highlighted many of these same shortcomings in the studies in question.[327]

Although we do not expect to see any regional reliability problems, we acknowledge that there could be localized reliability issues in some areas—due to transmission constraints or location-specific ancillary services provided by retiring generation—if utilities and other entities with responsibility for maintaining electric reliability do not take actions to mitigate such issues in a timely fashion. There are many potential actions that could be taken to address this problem and multiple safeguards to assure a reliable electricity supply.

First, utilities can help to assure reliability through proactive steps in coordination with relevant planning and regulatory authorities. As we said in the proposal, early planning is key. The industry has adequate resources to install the necessary controls and develop the new capacity that may be required within the compliance time provided for in the final rule.[328] Although there are a significant number of controls that need to be installed across the industry, with proper planning, we believe that the compliance schedule established by the CAA can be met. Many companies have begun to do the detailed analysis and engineering and are ahead of others in their compliance strategy. There are already tools in place (such as integrated resource planning, and in some cases, forward auctions for future generating capacity) that ensure that companies adequately plan for, and markets are responsive to, future requirements such as this final rule.

Second, companies that intend to retire EGUs should formally notify their RTO (or comparable planning authority in the case of non-RTO regions), state regulatory agencies, and regional reliability entities as soon as possible of their compliance plans, particularly with regard to any planned unit retirements. As we said before, in most places a closing plant will not be a cause for concern for reliability. The same is true of any outages required for retrofitting of units with controls. To the extent there is concern, however, early notification will provide an opportunity for transmission planners, market participants, and state authorities to develop solutions to avoid a reliability problem. In RTOs with forward capacity markets, owner/operators that do not bid generating capacity that they plan to shut down will provide an advance signal to market participants to take action to assure adequate future capacity. In all regions, early and public notification will allow market participants, planning coordinators and state authorities, as appropriate and in a timely fashion, to bring new generation on line, put demand side resources in place, and/or complete any transmission upgrades needed to circumvent a potential issue. Most RTOs only require 45 to 120 days notification of closure. In combined comments to EPA, 5 RTOs suggested that such notification should be made no later than 12 months after this regulation is final in order to allow a smooth transitioning to action to avoid a reliability problem. The EPA strongly encourages sources to provide notice to the RTOs as early as possible and believes that responsible owner/operators should and will do the early planning for compliance and provide early notification of their compliance plans, especially where such plans include retiring one or more units.

On the supply side, there are a range of options including the development of more centralized power resources (either base-load or peaking) and/or the development of cogeneration or distributed generation. Even with the current large reserve margins, there are companies ready to implement supply-side projects quickly. For instance, in the PJM region, there are over 11,600 MW of capacity that have completed feasibility and impact studies; the units representing this capacity could be on-line by the third quarter of 2014.[329] The EPA notes, as well, that in the 3 years from 2001 to 2003, industry brought over 160 GW of generation on line.[330]

Demand side options include energy efficiency as well as demand response programs. These types of resources can also be developed very quickly. In 2006, PJM had less than 2,000 MWs of capacity in demand side resources. Within 4 years this capacity nearly quadrupled to almost 8,000 MW of capacity.[331] In addition to helping address reliability concerns, reducing demand through mechanisms such as energy efficiency and demand side management practices has many other benefits. It can reduce the cost of compliance and has collateral air quality benefits by reducing emissions in periods where there are peak air quality concerns.

With regard to transmission, recent experience also shows that, in many cases, transmission upgrades to address reliability issues from plant closures can be implemented in less than 3 years. For instance, when Exelon notified PJM of its intention to retire four units,[332] it was determined that transmission upgrades necessary to allow retirement of two units could be made within 6 months of notification, transmission upgrades for the third unit would require slightly over 1 year and transmission upgrades to allow the fourth unit to retire could be made in approximately 18 months.[333]

The CAA allows CAA Title V permitting authorities the discretion to grant extensions to the compliance time of up to one year if needed for installation of controls. *See* CAA section 112(i)(3)(B)). If an existing source is unable, despite best efforts, to comply within 3 years, a permitting authority has the discretion to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls. Id. Permitting authorities should be familiar with the operation of the 1-year

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[326] James E. McCarthy and Claudia Copeland, Congressional Research Service, August 8, 2011, ''EPA's Regulation of Coal-Fired Power: Is a 'Train Wreck' Coming?''.

[327] Bipartisan Policy Center, June 2011, ''Environmental Regulation and Electric System Reliability.''

[328] As stated above, EPA has provided the maximum compliance time authorized under CAA section 112(i)(3)(A).

[329] Paul M Sotkiewicz, PJM Interconnection, Presentation at the Bipartisan Policy Commission Workshop Series on Environmental Regulation and Electric System Reliability, Workshop 3: Local, State, Regional and Federal Solutions, January 19, 2011, Washington, DC, *http://www.bipartisanpolicy.org/sites/default/files/Paul%20Sotkiewicz-%20Panel%202_0.pdf,* slide 6.

[330] Form EIA–860 Annual Electric Generator Report, *http://www.eia.gov/cneaf/electricity/page/eia860.html.*

[331] BPC slides cited above—slide 5.

[332] *http://www.exeloncorp.com/Newsroom/pages/pr_20091202_Generation.aspx?k=eddystone.*

[333] Cromby Units 1 and 2 and Eddystone Units 1 and 2—Deactivation Study, Updated September 7, 2010—*http://policyintegrity.org/documents/20100907-cromby-and-eddystone-retirement-study-posting-update.pdf.*

extension provision because EPA has established regulations to implement the provision and the provision applies to all NESHAP. *See* 40 CFR 63.6(i)(4)(A).

We believe that the permitting authorities have the discretion to use this extension authority to address a range of situations in which installation schedules may take more than 3 years including: staggering installations for reliability reasons or other site-specific challenges that may arise related to source-specific construction, permitting, or labor, procurement or resource challenges. Staggered installation allows companies to schedule outages at multiple units so that reliable power can be provided during these outage periods. It can also be helpful for particularly complex retrofits (*e.g.,* when controls for one unit need to be located in an open area needed to construct controls on another unit). The additional 1-year extension would provide an additional two shoulder periods (*i.e.,* seasons flanking annual high-demand periods) to schedule outages, thus enabling owners/operators to gain the full benefit of staggering outages in support of complex installations. The EPA believes that although most units will be able to fully comply within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. That fourth year should be broadly available to enable a facility owner to install controls within 4 years if the 3-year time frame is inadequate for completing the installation.

As we indicated at proposal, this source category is unique due to the large, complex and interconnected nature of electrical generation, transmission and distribution, and the critical role of the electric grid in the functioning of all aspects of the economy. The grid functions as an interconnected system that supplies electricity to end users on a continuous basis. Safe, reliable operation of the grid requires coordination among actions taken at individual units, including timing of outages for the installation of controls, derating, or deactivation. It was for this reason that we specifically addressed in the proposed rule reasonable interpretations of the phrase ‘‘installation of controls’’ in CAA section 112(i)(3)(B). We determined that it was important to provide Title V permit authorities with information that might be useful if they were asked to authorize a fourth year for specific EGUs.

The EPA took comment on whether the construction of on-site replacement power could be considered the ‘‘installation of controls’’ such that a fourth year would be available while the replacement unit is being completed for a unit that is retiring (*e.g.,* a case when a coal-fueled unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine). After reviewing the comments, EPA believes that it is reasonable for permit authorities to allow the fourth year extension to apply to the installation of replacement power at the site of the facility. The EPA believes that building replacement power constitutes the ‘‘installation of controls’’ at a facility to meet the regulatory requirements.

Commenters were generally supportive of the proposed approach described above, but a number of commenters suggested several additional situations that should be considered as the ‘‘installation of controls’’ such that it would be appropriate for permitting authorities to grant a 1-year extension beyond the 3-year compliance time-frame. In particular, commenters suggested that the 1-year extension should be available for a unit if a company's compliance choice was to retire that unit but doing so within the 3-year time-frame caused reliability problems for any of the following reasons: (1) Generation from the retiring unit is needed to maintain reliability while other units install emission controls; (2) new off-site generation was being built to replace the retiring unit, but the new generation was not scheduled to be operational within the 3-year time-frame and any gap between the time the existing unit retires and the new unit comes on line would cause reliability problems; and (3) transmission upgrades were needed in order to maintain electric reliability after the unit retired but could not be completed within 3 years.

While the ultimate discretion to provide a 1-year extension lies with the permitting authority, EPA believes that all three of these cases may provide reasonable justification for granting the 1-year extension if the permitting authority determines, for example, based on information from the RTO or other planning authority or other entities with relevant expertise, that continued operation of a particular unit slated for retirement for some or all of the additional year is necessary to avoid a serious risk to electric reliability.

In a case where pollution controls are being installed, or onsite replacement power is being constructed to allow for retirement of older, under-controlled generation, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies will have to go through a number of steps fairly early in the process including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement power. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement power is being constructed. Because companies will need to develop this information early in the process and because a determination can easily be made as to whether the schedule will exceed 3 years, the EPA believes that Title V permitting authorities should be able to quickly make determinations as to when extensions are appropriate.

In the three cases related to retirement of a unit without construction of onsite replacement power, additional information is needed. The Title V permitting authority should request that the affected company or companies provide information, including, for example, from the RTO or other planning authority for the relevant region, the state electric regulatory agency, NERC or its regional entities, and/or FERC or the DOE, demonstrating that retirement of a particular unit within the 3-year compliance period would result in a serious risk to electric reliability.

The first two situations involving a retiring unit—where one or more related existing units are upgrading pollution controls or a new unit is being constructed off-site—are similar to the situation we discussed in the proposed rule wherein a retiring unit at a facility runs an additional year while a replacement unit on the same site is constructed. In each of these situations, the retiring unit would be allowed to run so a unit compliant with the rule (either a retrofitted existing unit or a new unit) can come on line. We believe that these situations may, in the appropriate circumstances, constitute ones in which a 1-year extension for the retiring unit is ‘‘necessary for the installation of controls.’’ In these two situations, however, we believe that it would be appropriate for the Title V permitting authority to consider reliability concerns as a necessary factor before granting the additional year because continuing operation of the retiring unit is only ‘‘necessary’’ to the extent it is required for reliability. In each of these situations, the permitting authority should determine that the retiring unit is necessary to maintain reliability until the new unit comes on line or the other existing unit is retrofitted. Title V permitting authorities may determine that multiple retiring units are available to maintain reliability, but unless all the units are necessary to address the issue, it would likely be unreasonable to provide the additional year for all the identified units.

The third hypothetical situation identified above is one in which transmission upgrades are necessary to address a reliability issue resulting from the retirement of a unit in order to comply with this rule, where the upgrade cannot be completed by the 3-year compliance date. In terms of the functionality of the electric grid, this situation has some similarity to those discussed above. Here, it is the completion of the transmission upgrades, rather than bringing another compliant (retrofitted or new) unit on line, that would allow the retiring unit to come into compliance (by retiring) without threatening reliability. The general objective and result is similar: Reductions of the existing unit's HAP emissions (through retirement) while maintaining electric reliability. If such situations develop and the reliability problem has been properly demonstrated, permitting authorities should consider whether an extension under CAA section 112(i)(3)(B) may be provided.

The EPA continues to believe, based on the analysis discussed at the beginning of this section, that most, if not all, units will be able to comply with the requirements of this rule within 3 years. The EPA also believes that making it clear that permitting authorities have the authority to grant a 1-year compliance extension where necessary, in the range of situations described above, addresses many of the other concerns that commenters have raised. The EPA believes that the number of cases in which a unit is reliability critical and in which it is not possible to either install controls on the unit or mitigate the reliability issue through construction of new generation, transmission upgrades, or demand-side measures, within 4 years, is likely to be very small or nonexistent. This view is consistent with statements from commenters explicitly mandated with ensuring grid reliability.

The EPA's authority to provide relief from the requirements of this final rule beyond the fourth year is limited by the statute. If reliability issues do develop, however, the CAA provides mechanisms for sources to come into compliance while maintaining electric reliability. One area where the EPA has some measure of flexibility is with respect to the exercise of its enforcement authorities. The Agency has used such authority in the past to bring sources into compliance with the requirements of the CAA while maintaining electric reliability, although these authorities are not as flexible as suggested by some commenters.

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly well in advance of the date when a violation may occur. In light of the importance of ensuring electric reliability, however, the Office of Enforcement and Compliance Assurance will separately publish a document that articulates our intended approach with respect to sources that operate in noncompliance with this final rule to address a specific and documented reliability concerns.

That document provides a pathway for reliability critical units (as such units are described in the document) to achieve compliance within an additional year. The result is that qualifying reliability critical units may come into compliance within up to 5 years. This pathway is structured to maintain reliability, to ensure CAA compliance and to increase certainty for sources in planning by allowing a unit owner/operator to determine whether it qualifies for a compliance schedule well in advance of the MATS compliance deadline.

The EPA believes that there will be few, if any, situations in which it will be necessary to have recourse to the processes discussed in the document just described, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under that document. However, there is always the possibility that some unit owner/operator will be unable to address its reliability issues within 5 years and there is always the possibility that a unit owner/operator will be unable to timely comply with the MATS for some other reason. Consistent with its longstanding historical practice under the CAA, the EPA will address individual non-compliance circumstances on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution.

A number of commenters also raised concerns about inconsistencies between the compliance timelines under this final rule and existing state agreements with specific owners/operators to install pollution control equipment and/or retire EGUs. The EPA believes the flexibilities provided in this discussion allow for some discretion to address those cases, but that they may not be fully addressed. The EPA is supportive of such efforts and believes they can have important multi-pollutant health and environmental benefits. To the extent that the flexibilities discussed here do not fully address a particular situation, we encourage states and sources to contact the EPA as early as possible to discuss their individual circumstances.

G. Cost and Technology Basis Issues

1. Dry Sorbent Injection

Comment: Several commenters stated that there is limited commercial operating experience in using DSI to control acid gas emissions from coal-fired boilers. They suggest that the technology is not adequately proven for use in this application.

Other commenters disagree with statements made that DSI is not proven. One commenter stated that DSI is a mature technology. The commenter indicated that DSI is well suited for units that burn fuels with lower or mid-level sulfur contents, and is among the viable options available for a number of sources to achieve the proposed HCl limits. Thus, the commenter believes that DSI represents a real technology control option for many units, and is among the suite of technology options that certain units will be able to employ to meet the proposed HCl limit.

Response: As explained in this response and elsewhere in this preamble, the EPA agrees that DSI technology is proven and ready for commercial use in controlling acid gases from coal combustion. One of the largest coal-burning electric utilities in the U.S, American Electric Power (AEP), pioneered the practical use of DSI with trona, a sodium-based sorbent, for SO_3 mitigation. American Electric Power has implemented trona injection for that purpose across its entire bituminous coal-fired fleet where both SCR and wet FGD systems are in place.[334] Examples of coal-fired EGUs already using trona DSI to control SO_2 emissions include NRG Energy's Dunkirk Generating Station Units 1–4 and CR Huntley Units 67 and 68 in New York.[335] The Dunkirk units range in size from 75 MW to 190 MW. Much larger units may also be economic when using DSI for SO_2 control, as suggested by Dominion Energy's studies of adding DSI on two

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[334] *SO_3 Control: AEP Pioneers and Refines Trona Injection Process for SO_3 Mitigation,* Coal Power, March 2007, *http://www.coalpowermag.com/plant_design/SO3-Control-AEP-Pioneers-and-Refines-Trona-Injection-Process-for-SO3-Mitigation_29.html.*

[335] NRG Energy letter to RGGI, Inc, November 22, 2010, *http://www.rggi.org/docs/NRG_Nov_2010.pdf.*

625 MW units at the Kincaid plant in Illinois.[336] One of the largest suppliers of air emission control systems in the world, vouches that DSI is commercially proven for acid gas control:[337] [338]

Comment: Numerous comments were received on EPA's IPM modeling of DSI in the MATS analysis. A few commenters stated that DSI will not work on bituminous coals. Some commenters stated that DSI is only suitable for use on low sulfur, low chlorine western coals. Others stated that DSI is only likely to be used on relatively small units, and that larger units would use scrubbers for acid gas control. Several commenters expressed the opinion that because there is little commercial operating experience in using DSI to control SO_2 emissions from coal-fired boilers, EPA's IPM modeling assumptions on the efficacy and cost of the DSI control option are unjustifiably optimistic. Some commenters believe that DSI will not be as economic or as widely applicable for either SO_2 or HCl control as projected by EPA's IPM modeling. Commenters observe that wet or dry scrubbers for FGD, longer-standing control technologies for SO_2 and HCl, are more complex systems with a much higher capital cost than DSI. These commenters argue that the sector will need to retrofit many more FGD scrubbers than projected by IPM for MATS compliance and will therefore experience a much higher overall cost of compliance than projected by IPM, as well as needing more time and resources for retrofit construction. A few commenters suggested that EPA should base its MATS modeling on this more conservative outlook. A few commenters were concerned that EPA's DSI modeling assumptions relied on performance data from only one DSI vendor.

Some commenters were concerned that fly ash currently sold for beneficial uses will become unsalable because it will be contaminated by injected sodium-based DSI sorbents. Two commenters argued that EPA's IPM analysis understates DSI cost by not including the costs of foregone fly ash sales revenue and contaminated fly ash disposal. A few commenters observed that landfilling of sodium-based DSI solid wastes will produce leachate containing sodium and other compounds that are challenging to handle, thus requiring special landfill designs and a high cost for landfill disposal of DSI waste.

Response: The EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

The EPA disagrees that its IPM modeling of DSI is overly optimistic and therefore underestimates the costs of MATS compliance. In its IPM modeling, EPA restricts the availability of the DSI option to only those units that use or switch to relatively low sulfur coal: Less than 2 lb SO_2/MMBtu (*see* IPM documentation in the docket). The EPA's IPM projections for MATS compliance, therefore, already include the costs of any additional FGD scrubbers that are economically justified and projected for use on units using higher sulfur coals. The EPA models DSI assuming fine-milled trona as the injected sorbent. As mentioned by several commenters, sodium bicarbonate (SBC), which is processed from trona, is also suitable for use with DSI. Sodium bicarbonate is more reactive with acid gases than trona. It would require less tonnage of sorbent and less tonnage of waste disposal than trona for the same SO_2 removal effect, albeit at somewhat higher sorbent cost. Non-sodium based sorbents such as hydrated lime (calcium based) could also be used. Therefore, EPA's modeling of DSI technology does not include the full spectrum of sorbent choices that real-world applications enjoy, meaning that there may be opportunities for lower-cost applications of DSI that are not captured in EPA's projections for MATS. The EPA models DSI with trona injection rates corresponding to 70 percent SO_2 removal for all coals, assuming that an equivalent amount of sorbent is needed to provide 90 percent HCl removal, regardless of the low sulfur and chlorine content of western coals.

Senior technical staff from the EPA have carefully evaluated the key assumptions regarding the cost and operation of emission control technologies. In general, these staff believe that trona should have strong HCl reaction selectivity and, consequently, EPA's assumed trona injection rates may be overstated. The extent to which this assumption may actually overstate DSI control costs can be observed through DSI pilot testing for Solvay Chemicals by the Energy & Environmental Research Center (EERC) at the University of North Dakota.[339] The EERC's testing of trona DSI on a central Appalachian bituminous coal (1.3 lb SO_2/MMBtu) substantiates the strong HCl reaction selectivity of sodium-based sorbents, including trona, and calcium-based hydrated lime. The EERC's pilot testing shows that fine-milled trona, when well mixed into 325 °F flue gas upstream of a FF, provides 90 percent HCl removal at a SO_2 removal rate of less than 20 percent (as compared to EPA's modeling assumption of aligning 90 percent HCl removal with sorbent injection designed to achieve 70 percent SO_2 removal). The data show that 95 percent or higher HCl removal is readily obtained at somewhat higher SO_2 removal rates. Similarly strong HCl selectivity results were obtained using trona and an ESP at 650 °F. Test data from United Conveyor[340] on full-scale units also show these high HCl selectivity trends. Overall, these test data from multiple major vendors suggest that even if a SO_2 removal rate of 30 percent were required in order to obtain 90 percent HCl removal in the imperfectly mixed flow of a full-scale unit, it still appears that EPA's assumed trona injection rates may be as much as twice as high as would actually be needed in practice for certain applications. It is apparent that if EPA were to re-analyze MATS compliance with DSI injection rates reduced by 50 percent, there would be a corresponding reduction in the sorbent and related waste disposal costs that constitute most of the cost of using DSI.

Given the EERC test data, it is also apparent that most units that have ESPs and are burning low sulfur western coal could meet the HCl limit using DSI without the addition of a FF. If EPA were to re-analyze MATS compliance while allowing DSI use without the need for a downstream FF, it is apparent that there would be a very significant reduction in the overall number of FF retrofits projected, and a corresponding reduction in annualized capital costs. For the MATS proposal, the EPA modeled DSI on the assumption that all chlorine in coal converts to HCl, and that DSI would be the only mechanism by which the unit could prevent HCl from being emitted. Based on public

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[336] Dominion Energy, *BART Analysis for the Kincaid Power Plant,* January 2009, *http://www.epa.state.il.us/air/drafts/regional-haze/bart-kincaid.pdf.*

[337] Dry Sorbent Injection Systems for Acid Gas Control, Babcock & Wilcox, 2010, *http://www.babcock.com/library/pdf/ps-451.pdf.*

[338] Technologies for Acid Gas Control, Babcck & Wilcox, 2011, *http://www.babcock.com/library/pdf/ps-457.pdf.*

[339] Solvay Chemicals, Inc., HCl Removal in the Presence of SO_2 Using Dry Sodium Sorbent Injection, *http://www.solvair.us/SiteCollection Documents/presentations/20111214_hcl_presentation.pdf.*

[340] United Conveyor Corporation, *Dry Sorbent Injection for Simultaneous SO_2, HCl, and Hg Removal,* October 2011, *http://unitedconveyor.com/uploadedFiles/Systems/Systems_Sub/McIlvaine%20Multipollutant%20Removal%20Oct%202011.pdf.*

comments and a more thorough review of the ICR data, the EPA has introduced in final MATS modeling a recognition that the relatively high alkalinity of ash from subbituminous and lignite coals ''removes'' much of the HCl that would otherwise be emitted from combustion of these particular coals. The 2010 ICR data indicate that in some cases the ash itself removes sufficient HCl from these coals for MATS compliance; in effect, these acid-gas emissions are absorbed by coal ash and are captured by particulate control devices instead of being emitted in gaseous form. As a conservative measure, EPA's revised final MATS modeling assumes that 75 percent of HCl is removed by the ash for these coals. In the event that ash capture in practice is more effective than this 75 percent assumption, then EPA's analysis projects a conservatively higher level of DSI installations (and, thus, compliance cost) than would actually occur in practice. In any case, it appears that significantly less sorbent injection would actually be required in practice than assumed by EPA for these low sulfur, low chlorine coals, and that the IPM projected DSI operating costs are likewise higher for these coals than would be experienced in practice.

The EPA models DSI with sorbent injection occurring downstream of an existing electrostatic precipitator (ESP). The existing ESP is assumed to remain in service. The model adds a fabric filter downstream of the DSI injection point to capture the small amount of PM passing through the ESP plus the reacted and unreacted DSI sorbent. Most of the DSI projected by IPM, therefore, includes the costs of a retrofitted FF. This modeled configuration allows fly ash currently captured in ESPs to remain uncontaminated by DSI sorbent and, therefore, remain available for sale and beneficial use. The EPA conservatively models FF costs based on an assumed full-size system with an air-to-cloth ratio of 4.0. The FF costs could be somewhat less in practice if a smaller system (with an air-to-cloth ratio of 6.0) were used for the reduced DSI dust loading. The EPA observes that some of the owners of units with ESPs may chose to convert existing ESPs into FFs,[341] an option not modeled in IPM, but that would likely have a lower capital cost than a retrofitted FF. In the MATS proposal EPA modeled DSI with a waste disposal cost of $50/ton, based on a Sargent & Lundy DSI cost model prepared for EPA (*see* proposal IPM documentation in the docket). The EPA has continued to model DSI at this waste disposal cost for analysis of the final rule. However, recent discussions between senior technical staff from the DOE and the EPA have suggested that in some situations sodium sulfates, that would be formed by the injection of trona, could potentially leach out of the fly ash/sorbent mixture on contact with water. Although the technical staff recognized that these concerns are more relevant to bituminous coal-fired units where ashes are not cementitious, unless mixed with limestone or lime, they suggested that the impacts of potentially higher disposal costs be evaluated. Based on public comments, further investigations by Sargent & Lundy, and suggestions from the EPA and DOE technical staff, EPA's analysis of the final rule has included an IPM sensitivity case using a DSI waste disposal cost of $100/ton. The sensitivity case indicates that a 100 percent increase in assumed DSI waste disposal cost produces slightly less than a 1 percent increase in the projected cost of the rule.

Comment: A few commenters expressed the concern that there is an inadequate supply of trona to support DSI operations at the levels projected by the EPA for MATS compliance.

Response: The EPA projects that just over 50 GW of coal-fired capacity might retrofit with DSI for MATS compliance, thus reducing SO_2 emissions by about 1 million tons per year. Based on conservatively high trona injection rates, as discussed above, the EPA estimates that the amount of trona required to support DSI operations at this level is about 4 million tons per year. By comparison, the trona mining industry in the U.S. has a demonstrated production capacity of at least 18 million tons annually, and was running well below that capacity (16.5 million tons) in 2010.[342] [343] If the EPA's assumed trona injection rates are as much as 50 percent greater than actually needed for at least 90 percent HCl control, as discussed above, and given that some subbituminous coals will apparently need little or no sorbent injection for HCl control, there may already be an adequate surplus of trona production capacity to support DSI for MATS compliance. The EPA, therefore, concludes that trona supply for DSI is either already adequate, or will require at most a small increase in production capacity.

For all of these reasons, the EPA believes that its representation of DSI in MATS compliance modeling is reasonable, is properly limited to applications that are technically feasible, and reflects a conservative approach to modeling future use of this technology.

2. Economic Hardship

a. Job Losses and Economic Impacts

Comment: Several commenters indicated that they believe the proposed rule will weaken industry, cause job losses and hurt power consumers. One commenter reported that the proposed rule will affect 1,350 coal and oil-fired units at 525 power plants and that NERC reports that by 2018 nearly 50,000 MW of capacity will be retired by the proposed rule. Many of these commenters compared the cost estimated by EPA to a variety of other sources that estimate substantially higher costs of the rule. The commenters expressed concern that electricity price increases are likely to be up to 24 percent in some regions as a result of the proposed rule. In addition to the economic difficulty the proposed rule could place on consumers, the commenter believes that many in the energy sector will lose their jobs due to coal-fired capacity losses. The commenters believe the effects on coal-fired plants in the Southeast especially will mean the loss of high-paying, high-skilled jobs and drastic price increases in energy costs. Additionally, commenters expressed concern that increased electricity and natural gas prices would impact businesses in multiple sectors across the country.

Response: The EPA disagrees with the estimates presented by the commenters. The EPA has updated its analysis to reflect the final MATS. The Agency estimates the annual costs of the final rule in 2015 to be $9.6 billion in 2007 dollars. The estimate of early retirements of coal-fired units due to this rule is 4.7 GW, lower than the level estimated at proposal. Both of these estimates were prepared using the IPM, a model that has been extensively reviewed and has been utilized in several rulemakings affecting the power generation sector over the last 15 years. The Agency's analyses are credible and accurate to the extent possible, and all assumptions and data are made public. Limitations and caveats to these analyses can be found in the RIA for this rule.

The EPA estimates that there will be an increase of 3.1 percent in retail

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[341] TW Lugar, *et al., The Ultimate ESP Rebuild: Casing Conversion To a Pulse Jet Fabric Filter, a Case Study,* Electric Power Conference, May 2009, *http://www.cecoenviro.com/uploads/ESP%20to%20Fabric%20Filter%20Baghouse%20Conversion%20-%20Buell%20Case%20History.pdf.*

[342] *http://www.wma-minelife.com/trona/tronmine/tronmine.htm.*

[343] *http://www.wma-minelife.com/trona/TronaPage2/trona_production.htm.*

electricity price on average in the contiguous U.S. in 2015 as an outcome of this rule, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put this in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[344] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[345] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[346]

The Agency found that the readily discernible impact on long-term employment nationally within the most directly affected sectors should be small and the EPA also estimated that about 46,000 job-years [347] of one-time construction labor could be supported or created by this rule. This includes jobs manufacturing steel, cement and other materials needed to build pollution control equipment, jobs creating and assembling pollution control equipment, and jobs installing the equipment at power plants. Potential job increases from increased output by lower-emitting facilities (such as increased generation from well-controlled coal-fired plants that replace generation from older coal-fired plants) are expected to partially or fully offset potential job losses resulting from reduced output from higher-emitting facilities. The EPA analysis projects a net change in the directly affected EGU sector of between 15,000 net jobs lost to 30,000 net jobs gained on an annual basis.[348] See Chapter 6 of the RIA for further details.

The EPA has also looked at the possibility that changes in the price of electricity may influence the levels and geographic distribution of downstream economic activities, and associated employment. Projecting how potentially higher electricity prices may affect various downstream economic activities in particular regions as a result of this rule is challenging for several reasons: (1) There are significant uncertainties regarding projections of consumer- and location-specific electricity price changes in response to future firm-specific compliance strategies; (2) the availability of competitively-priced alternative energy sources (including energy conservation) and less electricity-intensive substitute goods and services may significantly mitigate potentially adverse economic consequences resulting from projected increases in electricity prices in ways which are not captured effectively in currently available models; and (3) available modeling tools are not configured to capture the effects over time of economically significant effects of cleaner air (*e.g.,* reductions in medical expenditures and improvements in labor productivity resulting from fewer lost work days) achieved by rules evaluated using single target year criteria pollutant and/or HAP benefits projections. After considering these methodological limitations, the Agency concludes that there is not a satisfactory methodology for projecting the downstream economic (including employment) effects of any changes in electricity prices due to this rule.

We expect the downstream economic effects of this rule to be small because electricity is only a small factor in the production of most goods and services.[349] A 3 percent increase in end-user electricity prices translates to a much smaller effect on prices and potential output of goods and services from end-users of electricity. Over time, the incremental effect of this rule on electricity prices is projected to diminish significantly; for example the difference in expected prices is projected to narrow from 3.1 percent in 2015 to 2.0 percent in 2020 as shown in Chapter 3 of the RIA.

Despite the absence of a satisfactory methodology for quantifying the potential economy-wide effects (including employment) of any potential increases in electricity prices resulting from this rule, the EPA expects the incremental effects of this rule on electricity prices to be small given the projected electricity price increases relative to historical levels and volatility in end-user electricity prices. Based on these projections and contextual information, the Agency believes that the incremental effects on electricity prices and economic activity of this rule are likely to be small relative to other factors influencing electricity prices, overall employment, and other aspects of economic activity.

Comment: Several commenters considered the proposed rule to be a tax on the American public, since utilities implementing upgrades will pass the costs on to the consumer. Commenters questioned the preference of Americans to subsidize renewable energy sources and put money into the proposed rule instead of other environmental programs with greater benefits. Commenters explained that the tax-like price increase reduces income of energy consumers and depresses business development. The commenters used California as an example of a state that uses low rates of coal-based electricity and cites companies that have left the state as a result of substituting higher cost forms of electricity for coal. A commenter stated that coal-derived energy will rapidly become more expensive, especially in the ''rust belt'' and Southeast region, as can be seen by the rate increase already requested in Louisville. A commenter believes the ''indirect taxation'' limits the ability of the economy to absorb the cost of retrofitting and new capacity projects, lowers discretionary spending and leads to job losses and lost tax revenues, given the restrictive timeframe for compliance.

Response: The Agency does not agree that this rule creates or alters any taxes on affected sources required under this rule to reduce their emissions of toxic air pollutants, nor are taxes created or altered or imposed on consumers of electricity which is provided to the market by affected sources. Moreover, unlike a tax, this rule does not generate government revenue. The rule does, however, indirectly address the problem of the ''externality cost'' of higher health risks and other adverse effects on the populations exposed to toxic air pollution emissions from affected sources. This rule may have the effect of

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[344] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[345] Ibid, EIA AEO 2010, Table 8–10.

[346] Ibid, EIA AEO 2010, Table 8–10 for price levels; and Chapter 3 of the RIA for electricity price differential.

[347] A ''job-year'' is a combined measure of jobs and job duration which is equivalent to one person being employed for one year. For example, 2 job-years could represent two years of employment for one worker, one year of employment for two workers, or 6 months of employment for four workers. Estimates of employment changes that involve non-permanent workers are usually reported in job years to give a sense of the total employment effects.

[348] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

[349] BEA. (2007b). Commodity-by-Industry Direct Requirements after Redefinitions, 2002. Available in: *2002 Summary Tables, 2002 Benchmark Input-Output Data.* Retrieved from *http://www.bea.gov/industry/io_benchmark.htm#2002data.*

reducing or eliminating a market distortion that provides an implicit subsidy to affected facilities. This implicit subsidy results from the fact that some facilities currently can avoid the costs of toxic air pollution controls by imposing higher health and other costs on those who are exposed to higher levels of toxic air pollution. The Agency also disagrees with the implication that the costs incurred by less-controlled sources to bring their toxic air emissions in line with their better-controlled competitors will lead to significant or debilitating changes in market and economic conditions. The Agency's estimate of the potential increase in retail electricity price is an average of 3.1 percent in 2015, with a range of increases by region from 1.3 percent to 6.3 percent. As shown in Chapter 3 of the RIA, the higher rates of potential electricity price increase tend to occur in those regions where electricity prices have been relatively low, due to some extent to reliance on coal-fired units which have been cheaper to operate due to underinvestment in toxic air pollution controls.[350] As shown in Chapter 3 of the RIA, all regions with year 2015 projected percentage increases in retail electricity prices above the contiguous U.S. average are also projected to have baseline retail electricity prices which are below the contiguous U.S. average price level in that year. In addition, natural gas prices will only increase by 0.3 to 0.6 percent on average over the time horizon of 2015 to 2030. As discussed above, for consumers of electricity in the commercial and industrial sectors, electricity tends to be a fairly small fraction of total costs of production, implying that the average projected electricity price increase of 3 percent will lead to only a small fractional change in the costs of providing goods and services to the economy. While some residential electricity consumers may similarly see a small price increase in retail electricity prices, it should be noted that these consumers tend to reside in the same area or region as the affected facility and so will also experience the improvement in air quality from the reductions due to the rule. The reduction in health risk and other improvements to quality of life associated with lower exposure to toxic and other air pollutants achieved by this rule will confer benefits on these consumers which include lower risks of premature mortality, lower morbidity, and improved productivity and competitiveness of U.S. workers due to reduction in work days lost to air pollution-related illness. The benefits of these improvements are projected to exceed costs of compliance by affected sources by at least six-fold. The potential price increases in electricity and natural gas should be considered in light of the substantial health, welfare, and economic benefits achieved by this rule.

Comment: Many commenters expressed support for the EPA's impact analysis and disputed claims by other commenters that the projected rule will harm economic growth. A number of commenters mentioned testimonials by power company CEOs stating that the proposed rule will not affect the economic health of the industry and a survey showing nearly 60 percent of the coal-fired units already comply with the EPA's proposed Hg standard, and several other meaningful quotes from utility executives. The commenters also pointed out that 17 states already require plants to address Hg pollution, with some imposing more stringent emission limits than the EPA proposes. The commenters believe that utilities use the threat of power plant closures and lost jobs to delay Hg reductions from coal-fired plants. Commenters also believe that the rules will drive innovation and job creation as new technologies to reduce pollution are created. Several commenters quoted the Economic Policy Institute finding that the proposed rule will increase job growth by 28,000 to 158,000 jobs by 2015 (including approximately 56,000 direct jobs and 35,000 indirect jobs), the University of Massachusetts study that showed an increase 1.4 million jobs in 5 years, and the Constellation Energy Group installation project that employed nearly 1,400 skilled workers. Commenters also cited the University of Massachusetts study statement that a net gain of over 4,200 long-term operation and maintenance jobs will result.

Several commenters observed that the positive impacts of the rule strongly favor its adoption. These commenters stated that, contrary to the unfounded assertions by critics of EPA and the rule, EPA has conducted a technically sound and conservative benefit-cost analysis showing that the proposed rule's estimated benefits are at least five times as high as its costs. One commenter stated, ''With sound, albeit unduly conservative, econometric modeling, EPA has also determined that the Toxics Rule will promote economic growth and create jobs in both the long and short term.'' Two commenters cited the EPA impact analyses by Dr. Charles Cicchetti which confirm this finding and state that the analysis underestimates the rule's net benefits and positive impacts on the nation's economy. By considering some benefits not monetized in the EPA analysis, Dr. Cicchetti concludes that the proposed rule will create $52.5 to $139.5 billion in net benefits annually, create 115,200 jobs, generate annual health savings of $4.513 billion, annual increases in GDP of $7.17 billion and $2.689 billion in additional annual tax revenues, and spur innovation and modernization of EGUs. The commenters state that the study findings show no need to delay implementation of the rule or needlessly duplicate economic analyses already completed.

Commenters reported that multiple researchers confirmed that the EPA's estimates of economic stimulus are conservative and that the proposed rule will stimulate job growth. A commenter quotes Dr. Josh Bivens of the Economic Policy Institute, who also found that EPA's conclusions were conservative. Dr. Bivens concluded, ''The EPA RIA on the proposed toxics rule makes a compelling case that the rule passes any reasonable cost-benefit analysis with flying colors—the monetized benefits of longer lives, better health, and greater productivity dwarf the projected costs of compliance * * * Whether regulation in general and the toxics rule in particular costs jobs is an empirical question this paper attempts to answer. In particular, this paper examines the possible channels through which the proposed toxics rule could affect employment in the United States and finds that claims that this regulation destroys jobs are flat wrong: ''The jobs-impact of the rule will be modest, but it will be positive.'' His report details the following major findings:

1. The proposed rule would have a modest positive net impact on overall employment, likely leading to the creation of 28,000 to 158,000 jobs between now and 2015.
2. The employment effect of the [MATS] on the utility industry itself could range from 17,000 jobs lost to 35,000 jobs gained.
3. The proposed rule would create between 81,000 and 101,000 jobs in the pollution abatement and control industry (which includes suppliers such as steelmakers).
4. Between 31,000 and 46,000 jobs would be lost due to higher energy prices leading to reductions in output.
5. Assuming a re-spending multiplier of 0.5, and since the net impact of the above impacts is positive, another 9,000 to 53,000 jobs would be created through re-spending.

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[350] *http://www.epa.gov/airmarkets/images/CoalControls.pdf.*

Response: The EPA thanks the commenters for these observations. The Agency's estimates of employment impacts, found in the RIA for the rule, are smaller than those identified by the some commenters, though the EPA uses a different methodology that focuses on impacts specific to the electric power sector.

b. Impacts on Low-Income Consumers

Comment: Commenters expressed concern that the EPA's overview of the price increases does not consider the hardships that will be the reality of increased prices on low-income or fixed-income households or small businesses. The commenter reports increases of $90 million in capital costs, $11.4 million in annual operating costs and $6.4 million in annual debt service costs to achieve compliance, which will lead to a 13 percent increase in rates for the proposed rule, and a 41 percent increase for all proposed and new regulation compliance costs. The commenter argues against the EPA's view that energy efficiencies will offset rate increases, because low income customers will need to use less electricity due to economic necessity. The commenter also sees large price increases for customers if units are converted to natural gas, which is approximately 2.5 times more expensive than the coal that the commenter currently uses to generate electricity.

Response: The EPA's estimates of increase, relative to the baseline, in the retail electricity price range from 1.3 percent to 6.3 percent regionally in 2015, with an average increase nationwide of 3.1 percent in 2015. Low-income households will thus see some increase in electricity price, but this increase should be modest. In addition, the increase in the price of natural gas as a result of this rule is expected to be 0.3 to 0.6 percent over a time horizon of 2015 to 2030. This increase in price is low enough that electricity customers should not experience a major increase in price resulting from any modest changes to electricity generated by natural gas. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[351]

c. State or Regional Impacts

Comment: Multiple commenters expressed concern over the impact of the rule on electricity prices and reliability in specific states or regions. These commenters were concerned that these impacts would adversely affect specific industries such as construction and manufacturing. One commenter suggested the EPA consider regional differences that will impact system reliability and costs, such as the increased impacts on regions relying heavily on coal and oil and encourages cooperation between the EPA and state and federal energy and environmental regulators.

Response: The Agency has studied possible impacts on resource adequacy as a result of this rule, and has determined that these impacts should not be significant. Furthermore, industry, along with relevant federal agencies, has the tools needed to address any reliability concerns. The Agency has prepared an updated feasibility TSD in support of the final rule, which is in the docket for this rulemaking.[352] The Agency has considered impacts on a regional basis as part of its overall analyses done using the IPM; these results are documented in the RIA for the rule and in the feasibility TSD.

The EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS. In Chapter 3 of the RIA, the EPA presents retail electricity prices by region in 2015, for both the base case and MATS policy case. The six regions that are projected to have retail electricity prices above the national average price in 2015 in the absence of MATS are projected to have increases that are below the national average increase following the implementation of MATS. Those regions that have projected retail electricity price increases that are above the national average are all projected to have retail electricity prices below the national average in the absence of MATS.

Comment: A commenter quoted National Mining Association statistics showing coal is responsible for $65.738 billion in annual economic activity, produces 1,798,800 jobs and $36.345 billion in annual labor income. The commenter reports that regions such as Appalachia, the Midwest and Rocky Mountain West will be significantly affected by the proposed rule, including increased unemployment. Other commenters stated that communities near existing coal-fired generation units will be especially hard-hit if the plants are permanently retired. The communities will suffer from job loss and diminished tax revenue.

Response: The Agency's analysis, as found in the RIA, shows that impacts to these regions are mixed. For Appalachia, coal production is projected to fall by 6 percent in 2015, while the Western coal producing region will experience a decrease of 3 percent in production in 2015. The Interior region is projected to see a 9 percent increase in production. Retail electricity prices are expected to increase by 1.3 percent to 6.3 percent in various parts of the country in 2015. Also, the estimated number of early retirements according to the Agency that may result from this rule is 4.7 GW in 2015, or less than 2 percent of all U.S. coal-fired capacity in that year. Thus, there may be some negative impacts from this rule in some regions, but these same regions will also experience some of the benefits, such as reduced premature mortality from less exposure to $PM_{2.5}$ emissions as shown in Chapter 5 of the RIA. As discussed previously, the EPA's analysis shows that retail electricity price increases will not fall disproportionately on a specific region. In fact, those regions experiencing the largest change in prices are projected to have retail electricity prices below the national average both in the absence of MATS and after the implementation of MATS.

The results of the EPA's employment analysis, found in Chapter 6 of the RIA, indicate that the final MATS has the potential to provide significant short-term employment opportunities, primarily driven by the high demand for new pollution control equipment. While the employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements, some of these workers who lose their jobs due to plant retirements could find replacement employment operating the new pollution controls at nearby units. Finally, job losses due to reduced coal demand are expected to be offset by job gains due to increased natural gas demand, resulting in a small positive net change in employment due to fuel demand changes.

While shifts in employment are difficult for those directly affected, and the Agency remains concerned about the challenges job shifts can bring to the

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[351] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[352] *See* ''An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule'' in the docket.

individuals affected, Bureau of Labor Statistics data indicate that compliance with pollution control requirements is a relatively very small contributor to overall employment shifts in the U.S. economy. Specifically, the main cause of mass layoffs over the last four years according to 2007 to 2011 Bureau of Labor Statistics data is ''lack of business demand,'' accounting for over 40 percent of the layoffs reported by industry. In contrast, all types of regulatory actions (including health, safety, and environmental) by all levels of government (Federal, State, local) combined were cited as the primary factor in only 0.2 percent of mass layoffs over the same period.[353]

d. Retirements of Coal-Fired EGUs and Shutdowns

Comment: A commenter discussed the economic factors behind EGU retirements. These factors include the cost of alternative generation using natural gas, the cost of implementing demand response measures that can be bid into capacity markets, and the cost of continuing to generate power from an existing unit. The commenter states that regardless of the costs associated with the Toxics Rule and other EPA electric power industry regulations, some power plants were already economically unsustainable. The commenter quotes M.J. Bradley, who points out, ''[o]f the 122 coal units in PJM with capacity less than or equal to 200 MW, 35 failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM * * * in addition to approximately 10 GW of coal generation that has or will be retired during the 7 years from 2004 to 2011, another 11 GW faces a troubling economic outlook.'' The commenter provides confirmation of this by the most recent PJM capacity auction, where approximately 6.9 fewer GW of coal-fired capacity cleared the auction (1.85 fewer GW were offered) as compared with the prior year's auction, and an additional 4.836 GW of new demand response (energy efficiency) resources cleared the auction. Thus, the commenter states, some claims linking retirements to the MATS are overstated and misleading. The commenter gives the example of the American Electric Power attempt to link its planned plant closures to the MATS, but those plants already are slated to either close or to upgrade controls to comply with existing laws. The commenter goes on to quote three independent studies that support the finding that over 50 percent of the fleet is equipped with scrubbers and the number will increase to nearly ⅔ by 2015.

Response: The EPA agrees with the findings of the independent studies mentioned by the commenter.

e. Impacts on Mining

Comment: Multiple commenters mention the proposed rule's impact on mining. One commenter mentioned increasing energy costs for the U.S. mining industry, resulting in fewer projects and associated jobs, as well as increasing dependence on foreign mineral resources. Commenters see mining impacts being disproportionally large for lignite mines, which are dependent on their co-located lignite-fired power plants. The commenters state that if the plant closes, there is no market for the lignite and the mine will also close, displacing plant workers. These impacts are largest in Texas, the largest coal consuming state and fifth largest coal producing state, as well as a deregulated electricity market. One commenter pointed out that the Texas coal market provided a buffer against natural gas price volatility and in particular believes the proposed rule does not take into account the emission reductions already achieved by industry in general and their company in particular. A commenter stated that impacts will be magnified in Texas, since it is the largest coal consuming state and mines lignite. A commenter indicated they believe it is unclear the extent to which EPA includes the impacts on the mining industry that will result from this rule.

Response: The Agency presents impacts on the coal mining sector from this rule in the RIA. Given the modest increase in coal and other energy costs associated with the rule, the Agency does not expect widespread impacts on coal mining. The Agency's modeling accounts for all emission controls and programs installed and/or implemented up through December 2010, including those in Texas.

f. Flexible Regulations

Comment: Several commenters expressed concern over the potential impacts of the regulation and believe that the requirements should be more flexible in order to mitigate these impacts.

Response: The EPA believes the requirements of the final rule have been made as flexible as possible consistent with the CAA. The final rule allows some flexibility, including allowing averaging across units in the same subcategory at a facility, allowing for an option of an input or output standard for existing units, and allowing for alternative compliance options (*e.g.,* for coal, filterable PM or total non-mercury metallic HAP or individual HAP metals). In addition, the Agency is not prescribing specific technologies as part of this final rule, but instead requiring emissions limitations be met. This approach allows the industry to find the most cost-effective approach to meeting the requirements while ensuring considerable public health benefits.

g. Temporary vs. Permanent Jobs

Comment: A commenter expressed disagreement with the EPA prediction of new jobs created, because the commenter believes far more plants will shut down than the EPA predicts, resulting in higher job losses. The commenter also pointed out that while jobs running power plants are permanent, the jobs predicted to be created by the proposed rule are short term construction jobs, and will all occur in the same short timeframe for compliance. The commenter also stated that the EPA estimate does not include the opportunity cost of lost construction jobs due to new power plants that will not be constructed due to the proposed rules.

Response: The Agency believes that the employment impacts of the final rule will be small, as has been the case historically with regards to environmental regulation. The Agency does provide an estimate of the long-term employment impacts to the electric power sector in the RIA for the rule, and that estimate shows a range of impacts from 15,000 net jobs lost to 30,000 net jobs gained (all annual), but also recognizes important limitations to these estimates. The Agency's estimate of impacts to short-term jobs, including those in construction, accounts for both losses and gains that result from the rule. This is shown in Chapter 6 of the RIA.

Comment: Commenters believe that installation of new pollution controls would be a job-growth opportunity in their states because money spent on controls for power plants creates high-quality jobs in steel, cement and other materials, as well as in the assembling of the equipment as well as installing and operating it. A commenter shares the Alabama Fisheries Association estimate that the water-based recreation industry brings in over $1 billion per year to the state's economy though the state ranks third for imperiled fish with 61 bodies of water cited for Hg contamination. The commenter believes the HAP accumulating in the waterways

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[353] U.S. Bureau of Labor Statistics, 2011. Extended Mass Layoffs in 2010. *http://www.bls.gov/mls/mlsreport1038.pdf.*

threatens the industry with permanent job-losses and lost revenue.

Response: The Agency agrees with the commenter that the reduction in HAP that will take place as a result of the rule over time will help to improve waterways in Alabama and thus help the water-based recreation in that state. More information on the benefits of Hg and other HAP reductions can be found in Chapter 4 of the RIA for the rule. The Agency also agrees with the commenter that the addition of control equipment for EGUs may stimulate employment in a variety of industries.

h. Natural Gas

Comment: A commenter states that natural gas use is only an option in places where infrastructure exists to supply sufficient natural gas to the EGU and other local needs and reports that year-round reliable gas delivery is rare due to requirements to meet the other needs. The commenter says that gas interruptions are prevalent in the winter, but can happen year-round, and the costs of establishing a natural gas line to a power plant can be tens of millions of dollars or more, and moving a plant to a gas source can take many years. The commenter describes the options for a Norwalk Harbor plant, and explains that the modifications are costly and difficult even before considering the modifications needed to alter the boiler and fuel supply system to allow natural gas combustion.

Response: The final rule does not prescribe either pollution control technologies to be used, nor does it dictate the types of fuels that should be burned. The requirements of the final rule are designed to allow industry to find the most cost-effective approach to addressing harmful emissions that are covered by this action. The Agency believes that cost-effective technologies exist today and have been deployed on many power plants, and utilities will be able to find intelligent solutions to address harmful emissions. The EPA has provided supporting information as part of the preamble and RIA for this rule, along with the feasibility TSD, which demonstrate the availability and performance of technologies to meet the requirements of the final rule.

Comment: A commenter discusses the factors that could lead to higher natural gas prices not currently reflected in the EPA impact projections, including industrial load and demand not rebounding to 2008 levels and the influence of liquefied natural gas exports. The commenter asks that the EPA address a variety of factors related to its natural gas assumptions.

Response: The Agency has fully documented its assumptions and framework for modeling natural gas in IPM for both the proposed and final MATS. This information can be found in Chapter 10 of the IPM documentation (*http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter10.pdf*). The documentation provides a thorough overview of the natural gas module, describes the very detailed process-engineering model and data sources used to characterize North American conventional, unconventional, and frontier natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. Also documented are the resource constraints, liquefied natural gas (LNG), demand side issues, the natural gas pipeline network and capacity, procedures used to capture pipeline transportation costs, natural gas storage, oil and natural gas liquids (NGL) assumptions, and key gas market parameters.

i. Compliance Timeline and General Timeline

Comment: A commenter states that the proposed rule will require costs be passed on to consumers, meaning state public utility commissions will be flooded with requests for rate increases from utilities trying to recover expenditures. The short deadline will also result in a large number of extension requests made to state permitting authorities, further burdening them.

Response: The compliance date for this rule for existing sources will be 3 years and 60 days after publication of the final rule in the **Federal Register**, or approximately March 2015. Thus, there will be some time before the impacts of this rule such as any increase in retail electricity prices become a concern. It also should be noted that increases in retail electricity prices will be 3.1 percent on average in 2015, with a range regionally from 1.3 percent to 6.3 percent.

Comment: A commenter reports that they will need to install add-on pollution controls to meet the proposed emission standards as well as implement other physical or operational changes. The commenter expresses concern about the number of pre-construction steps that would be required, as well as the new construction activities and the challenges of scheduling sequence relative to interconnections and other tie-in considerations involved in compliance.

Response: The Agency has addressed concerns with the feasibility and timing of control installations in its report on the subject (*see* feasibility TSD contained in the docket for this rule).

Comment: Multiple commenters do not believe that labor availability will constrain control installation in the required timeframe and cites an Institute of Clean Air Companies (ICAC) response that it will not for these reasons:

1. The power sector has demonstrated ability to install large number of systems in short time period;
2. The majority of coal plans have installed control systems already;
3. Fewer resource and labor-intensive control options being used for compliance; and
4. End users have utilized cost reducing and implementation efficiency strategies for efficient deployment of technologies.

Another commenter states that a wide range of technical and economically feasible practices and technologies are available currently to meet the emission limits and are in use around the country.

Response: These comments are generally consistent with the conclusions of the Agency's analyses on feasibility of control installations for this rule as found in the feasibility TSD in the docket for this rulemaking.

j. Burden Outweighs Environmental Gain

Comment: Several commenters state that the EPA has no data relating to benefits from reducing non-mercury HAP, so the costs of the proposed rule exceed the HAP benefits by 29,000 times. One commenter states that the impact analysis was largely focused on Hg with little support for other HAP reductions and failed to provide account of true costs and benefits.

Response: While we are not able to monetize the benefits from reductions of non-mercury HAP that will take place, these important effects are discussed qualitatively in Chapter 4 of the RIA. The quantified benefits of this rule include the reductions in non-HAP emissions such as SO_2 and $PM_{2.5}$ that will occur as a co-benefit of this rule as modeled by EPA. The total benefits are estimated to outweigh the total annual costs of the rule by a margin of either 3 to 1 or 9 to 1, depending on the benefits estimate and discount rate used. These reductions are credible and are considerable in size. The estimates of these benefits reflect the latest scientific understanding on the subject. More information on the estimates and the methodology for their preparation can be found in the RIA for the rule.

Comment: Several commenters consider the proposed rule to be the most expensive clean air rule ever. They point out the estimated $10.9 billion annual cost in 2015 and approximate 1,200 existing coal-fired EGUs affected, both of which were estimated by the EPA. Commenters believe the EPA's estimates are incorrect and the true cost will be far more, due to cumulative effects of all proposed power sector rules, and indirect costs from job losses, reduced productivity and competitiveness resulting from electricity costs. They ask the EPA to keep these high costs in mind when evaluating impacts of the proposed rule and consider the costs with respect to the benefits. One commenter requests that the EPA explain how its approach utilized ''the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible'' and includes analyses by EIA, EEI, NERC, NERA, Credit Suisse, ICF, and Burns & McDonnell.

Response: As noted earlier, the Agency did not prepare a cumulative impact analysis to accompany the rule for the following reasons: (1) The various EO requirements that the Agency must comply with require us to estimate impacts specific to this rule; (2) decisionmakers and the public need to know the impacts specific to a particular rule in order to judge the merits of the regulation; and (3) estimates specific to a particular rule are more transparent than those from a cumulative impact analysis. A cumulative impact analysis lumps several regulations together and can potentially mask a high-cost/low benefit regulation among other rules that may have large net benefits. By analyzing each regulation separately, EPA makes clear statements about the impacts, costs, and benefits that are estimated as a result of this particular regulation.

This does not, however, mean EPA has failed to incorporate these regulations into this analysis. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the IPM base case reflects the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case provides meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions, while isolating the incremental impacts of MATS. These results are presented in Chapter 3 of the RIA.

Additionally, the Agency does reflect on the cumulative impacts of our regulations. In March 2011, EPA issued the Second Clean Air Act Prospective Report which assessed the benefits and costs of regulations pursuant to the 1990 Clean Air Act Amendments. The study examines the cumulative impact of these regulations (found at *http://www.epa.gov/air/sect812/feb11/summaryreport.pdf*). As shown in the report, the direct benefits from the 1990 Clean Air Act Amendments are estimated to reach almost $2 trillion for the year 2020, a figure that dwarfs the direct costs of implementation ($65 billion). The full report is at *http://www.epa.gov/air/sect812/prospective2.html.*

The direct benefits of the 1990 Clean Air Act Amendments and associated programs are estimated to significantly exceed their direct costs, which means economic welfare and quality of life for Americans were improved by passage of the 1990 Amendments. The wide margin by which benefits are estimated to exceed costs, combined with extensive uncertainty analysis, suggest it is very unlikely this result would be reversed using any reasonable alternative assumptions or methods. The analysis presented in the RIA for the current regulation uses a similar methodology.

The techniques employed by the Agency for generating benefits and costs, and consider the most recent and complete data available to the Agency. The EPA recognizes that the analyses have caveats and limitations, and we discuss our analyses and their caveats and limitations in the RIA for the rule, as well as in the benefits section of the preamble. The Agency has also revised the cost analyses for the final rule to reflect data received in public comments on the proposed rule, and costs are lower than when the rule was proposed.

k. Impact on State Regulators

Comment: Several commenters expressed concern over the burden imposed on state regulatory agencies by the rule.

Response: The Agency has estimated the costs of implementation of the rule to states that own EGUs affected by the rule, and has included this analysis in the RIA. The Agency has updated this analysis for the final rule and it is included in the RIA. While the EPA has not prepared an analysis of the impacts of the rule on state programs, the Agency does not believe the rule will be unduly burdensome to the state regulatory agencies. The EPA works closely with state regulatory authorities to ensure that the rules are implemented properly, and the Agency will continue to do so in support of this final rule.

Comment: A commenter states that the reductions in SO_2 and $PM_{2.5}$ required by the proposed rule will assist state and local air pollution control agencies to meet health-based air quality standards, reduce haze and improve visibility. The commenter points out that substantial reduction in emissions made by the very large sources under the proposed rule will lead to fewer pollution controls needed at smaller sources to meet health-based ambient air requirements. This is a far more cost-effective approach than controls at smaller facilities and is the lowest cost path to improved public health and a cleaner environment.

Response: The EPA acknowledges that the HAP standards in this final rule will lead to considerable co-benefit reductions in PM and SO_2.

l. Miscellaneous

Comment: A few commenters discussed the impact of the rule on the federal budget deficit. One commenter points out that the proposed rule will affect the federal budget in two ways:

1. Direct compliance costs to electric generating units (EGUs) owned by federal agencies; and
2. Pass-through compliance costs paid in the form of higher prices for electricity purchased by federal agencies.

Response: The Agency estimates the direct compliance costs to EGUs that are federally owned as part of the overall cost analysis completed for the proposal and disclosed in the RIA for the rule. The Agency does not provide an estimate of the impact on federal agencies from higher electricity prices associated with the rule, however. This type of analysis is not required under EO 12866 and statutory requirements.

H. Testing and Monitoring

Comment: Commenters raised numerous issues with the testing and monitoring requirements for initial and continuous compliance. The following discussion highlights the comments and responses to a number of the critical issues and describe where the comments have resulted in a significant rule change or where we disagreed with commenters' suggestions of issues or need for changes in the rule. Additional comments and responses are addressed in the Response to Comments document included in the docket for the final rule.

Test Methods. A number of commenters suggested that we should allow for the use of Method 5B to determine compliance with the PM emission limit. In addition, a number of commenters objected to the frequency of stack testing when used as the method for demonstrating continuous compliance. Commenters also objected to the requirement for testing one pollutant when the source was complying with an optional surrogate (or vice versa); for example, commenters objected to testing for HCl if a unit was complying with the optional SO_2 limit, or testing for metals if the unit was complying with the optional PM limit.

Response: Although Method 5B is specified for wet scrubber-controlled utility boilers under 40 CFR part 60, subparts D, Da and Db, we are excluding Method 5B for demonstrating compliance with the filterable PM emissions standard in this final rule. The extended high temperature heating of the filters prior to weighing as specified in Method 5B would introduce differences between the compliance test data and the data that underlie the filterable particulate standard. Because the test data that underlie and filterable particulate standard are based primarily on Method 29 and Method 5 data collected at 320 °F or comparable filterable particulate methods, we are specifying those same methods for determining compliance with the standard.

For stack test frequency, we modified the final rule to require quarterly testing to demonstrate continuous compliance. In addition, we agree that testing should be required only for the emission limits that your source is complying with, and, thus, the final rule does not require testing of both the pollutant and the surrogate.

Comment: Fuel Analysis Methods. A number of commenters raised various concerns with the fuel analysis methods specified in the proposed rule.

Response: Based on the comments received and a further review of the technical challenges associated with the proposed fuel analysis requirements, we have not finalized the proposed fuel analysis requirements. As the rule no longer requires operating limits based on fuel content or fuel analysis, the comments on this issue are largely moot. For LEEs, we agree that the proposed LEE ongoing eligibility requirements were overly burdensome and restrictive. As a result, existing solid or liquid fired units that qualify for Hg LEE status will be required to conduct a 30-day test for Hg using Method 30B each year. Neither fuel analysis nor adherence to an operating limit will be required. Should an annual test show ineligibility for LEE status, the source will revert to the requirements for Hg monitoring using CEMS or sorbent traps or, for oil-fired units, quarterly emissions testing. Existing solid or liquid fired units that qualify for non-mercury LEE status will be required to conduct a stack test every 3 years, and neither fuel analysis nor adherence to an operating limit will be required. Should the stack test show ineligibility for LEE status, the source will revert to using CEMS or PM CPMS or conducting quarterly emissions testing.

Comment: Operating Parameter Limits: Some commenters objected to the use of enforceable operating parameter limits, requested that the rule be more consistent with the compliance assurance monitoring program, and raised specific objections to certain parameters required for certain control devices. Commenters also raised concerns about a PM CEMS operating limit establishing a de facto more stringent PM emission limit than the one being tested for under the total PM standard in the proposal.

Response: We believe that continuous monitoring in the form of CEMS, sorbent trap monitoring systems, and PM CPMS, or frequent stack emissions testing are appropriate to ensure ongoing compliance with this final rule. We also agree with commenters that some of the monitoring provisions in the proposal may have been duplicative and unnecessary. In order to provide flexibility in the final rule, we have retained a source's ability to define an operating limit and to monitor using a PM CPMS as an option to periodic filterable PM emissions testing.

The final rule establishes the PM CPMS as an operating limit monitor and not a direct filterable PM emission monitoring requirement that meets PS 11 requirements. Although we recognize the importance of continued control device performance to ensure emissions minimization, we also are aware that other rules that apply to these units including, but not limited to, the Operating Permits rule, the Compliance Assurance Monitoring rule, the ARP rules, and the NSPS already require continuous monitoring in most cases. Those rules will remain in effect so the need to impose additional operating limits monitoring or CEMS on those units is much reduced.

The final rule also provides for the use of a PM CEMS to determine compliance with the filterable PM emission limit if the source elects to use this approach. In that case, the PM CEMS is used as the direct method of compliance and no additional testing is required other than tests that are required as part of satisfying the requirements in Performance Specification 11 in Appendix B to 40 CFR part 60 and Procedure 2 in Appendix F to part 60. The EPA provided this option in response to the comments in order to provide a straightforward direct measure of compliance that some sources may want to implement.

Comment: Hg CEMS. Commenters raised a number of technical concerns about Hg CEMS. Many commenters requested modifications so that the requirements would be more consistent with 40 CFR part 75 monitoring requirements. Some commenters questioned the ability of the technology to demonstrate compliance with emission limits at very low levels especially for new sources. Commenters also opposed high data availability requirements given that the technology is new and difficult to operate and maintain.

Response: We indicated in the proposed rule the intent to adopt CAMR-based requirements for Hg monitoring in place of the general 40 CFR part 63 performance specifications and QA requirements. With CAMR, these operating and reporting requirements for Hg CEMS went through notice and comment rulemaking for the same sources as covered by this final rule. Although CAMR was set aside on other grounds, these technical specifications and QA requirements reflect significant input from stakeholders and analysis by the EPA to establish an appropriate foundation for Hg monitoring at electric utilities under the CAA. For the final rule, we have made conforming changes to ensure that this intent is carried out effectively throughout the rule text and Appendix A, as well as including certain additional clarifications based on the input received in response to the proposed rule. We have also removed a cycle time test as unworkable for certain types of Hg CEMS.

The final rule provides the option for use of either Hg CEMS or sorbent trap monitoring systems. We believe the record clearly shows these to be proven technologies each providing certain advantages. For existing and some of the new unit standards, the level of the NIST-traceable Hg gas standards will be adequate and consistent with existing applications of Hg CEMS. For the lowest limits and other applications where an integrated sampling system offers advantages, affected facilities may opt to use sorbent trap monitoring systems to comply. There are data in the recent draft report entitled ''Determining the Variability Of CMMS At Low Hg Levels,''[354] that demonstrate reasonable

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[354] *http://www.icci.org/reports/10Laudal6A-1.pdf.*

performance of at least one Hg CEMS at Hg levels below 1.0 microgram per cubic meter (μg/m^3) down to approximately 0.1 μg/m^3. Finally, there is no specific minimum data availability requirement for Hg CEMS (or any other CMS required under this final rule). This issue is discussed further below.

Comment: SO_2 CEMS: Although commenters were generally supportive of the ability to use SO_2 CEMS for units with FGD installed to demonstrate compliance with an alternate SO_2 emission limit instead of the HCl emission limit, there were some concerns with aspects of the proposal. Commenters requested that the SO_2 monitoring requirements rely on 40 CFR part 75 given that their sources were already meeting those requirements and that this rule not establish any new requirements, especially a fourth linearity level and the application of 7-day calibration error tests for units with low concentrations (where 40 CFR part 75 provides an exemption). Commenters were also concerned that the rule language only allows the option where the FGD is operated ''at all times'' which seems to imply that the option is not allowed if the source ever bypasses the FGD for start-up, shutdown, or malfunction reasons.

Response: After reviewing the comments and assessing the need for an additional calibration gas at the emissions limit, we have removed this requirement from the final rule while retaining the requirement for a linearity check even for SO_2 monitors with low span values (≤ 30 ppm). A source can already report linearity tests for these units within the context of the existing ECMPS reporting without triggering any critical errors. This test can be accommodated within the current framework without causing issues for 40 CFR part 75 reporting. The requirement for a 7-day calibration error test is removed. For the ''at all times'' language, we have clarified this in the final rule. The intent is that the FGD be operated during all routine boiler operations, and not operated intermittently, seasonally, or on some other non-fulltime basis.

Comment: HCl CEMS. In general, commenters argued that HCl CEMS do not have an approved performance specification and are not widely demonstrated as a proven technology. Those concerns were also mentioned for HF CEMS.

Response: We disagree with commenters' contention that continuous HCl monitoring is premature or not available for the measurement at the emission limits set in the final rule. HCl CEMS are being used on source categories such as municipal waste combustors and EGUs. We have reviewed HCl CEMS vendor technology claims and found sufficient capability to support this rule requirement. We are engaged with representative stakeholders to develop a generic performance specification for HCl CEMS scheduled for completion in time to be responsive to compliance with this rule.

The final rule provides several options for HCl and/or HF monitoring including:

(1) Using Fourier Transform Infrared (FTIR)-based HCl CEMS and/or HF CEMS complying with Appendix B to the rule which relies on PS 15,

(2) Seeking approval for an alternative HCl monitoring procedure through 40 CFR 63.7(f),

(3) Monitoring compliance continuously with the alternate SO_2 emission limit at coal-fired or other solid fuel affected facilities equipped with FGD technology for SO_2, and

(4) Quarterly reference method testing.

Including these options in the final rule provides flexibility to adopt CEMS monitoring options as the technology continues to mature and the new, non-technology-specific EPA performance specifications becomes available.

Comment: Bypass Stacks. Several commenters raised concerns about the technical feasibility of monitoring bypass stacks with a CEMS.

Response: We have modified the bypass stack monitoring requirements. Under 40 CFR part 75, we allow the use of a maximum potential concentration value for reporting when emissions are vented to a bypass stack. That approach works within the context of an emissions trading program, but is not appropriate when evaluating compliance with a specific emission limit. Thus, we have provided two other options. One is to monitor the bypass stack, consistent with the final rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime and hours of deviation from the monitoring requirements. Note that a source's units must continue to meet their 30-boiler operating day emissions limits during malfunction periods.

Comment: 40 CFR part 75 Issues. There were a number of general comments about the value of relying on 40 CFR part 75 requirements, including elements such as conditional data validation. The commenters generally agreed that the 40 CFR part 75 bias test and bias adjustment factor, and the 40 CFR part 75 substitute data provisions should not apply. Instead of substitute data, many commenters suggested that we needed to clarify the valid reasons for monitor downtime and establish an appropriate minimum data availability requirement.

Response: We have attempted to harmonize the CEMS requirements in this final rule with those under 40 CFR part 75 wherever appropriate. One of those examples is the inclusion of conditional data validation for Hg CEMS. We disagree that this final rule needs a minimum data availability requirement. We have not included any specific minimum data availability requirement for CEMS or other monitoring in this final rule nor do we provide a specific tool for data substitution. We believe that there are other provisions in the final rule to provide incentives to conduct monitoring in a manner consistent with good air pollution control practices and to provide data sufficient to demonstrate compliance with a relatively long-term (30-boiler operating day) emissions rate limit. We agree that data quality certainty associated with any calculated value decreases with the collection of less data such as would occur with extended periods of monitoring system downtime. Even so, we believe also that it is necessary and critical for compliance with the regulation that a source use all measured data collected during an averaging period to assess compliance regardless of any periods of missing data. Sources should not disqualify any data otherwise meeting required data quality requirements simply because there were data missing for other hours or days of the averaging period.

Instead of a minimum data availability threshold that would invalidate data collected for some averaging periods because one did not collect data for at least a specified percent of an averaging time, the final rule requires that a source report as deviations to the rule failure to collect data during required periods if these deviations are not covered by exceptions allowed in the final rule.

On the issue of applying a data substitution procedure to represent actual emissions or pollution control performance, we are not requiring data substitutions under this rule. We believe, however, that defensibility concerns make it incumbent on the source to collect and evaluate other information in accordance with 40 CFR section 63.6(f)(3) during periods of monitoring downtime to assure compliance with the applicable emissions limitations and standards.

We believe that enforcement authorities also can and should determine whether a source is meeting any monitoring system operating requirements. Should the source or the enforcement authority be concerned about the representativeness of data such as during periods of missing data, either one may consider collecting information through other means (*e.g.,* supplemental emissions testing) to fill data gaps not only because such gaps are deviations from the rule but such gaps can lead to uncertainty about compliance status.

We further believe that the final rule provides sufficient means to ensure CMS performance and ongoing compliance without specifying an arbitrary numerical minimum data availability or data substitution requirement. We believe that specifying failure to collect required or otherwise excepted data as a deviation from the rule will provide the necessary incentive to collect data sufficient to demonstrate compliance with the limits in the final rule.

Comment: Recordkeeping. Several commenters opposed the requirements related to maintaining records on site and for 5 years.

Response: We believe the recordkeeping and retention requirements are consistent with other requirements already in place, specifically 40 CFR 63.10 (b).

In addition, the 5-year retention period is the general rule for all recordkeeping for all sources under the part 70 operating permits program. Given that the General Provisions for 40 CFR part 63 and part 70 already establish a 5-year retention period, we believe it is justified in using those precedents for the retention periods under this subpart. If we stayed silent on retention period in this subpart, the General Provisions would provide for the 5-year retention as would the part 70 requirements. Thus, this action does not establish any new retention requirements, but merely confirms that the existing retention requirements apply.

Comment: Electronic Reporting. In the proposed rule, we requested comment on using ECMPS for reporting under this rule, as well as other options including the ERT. Commenters generally supported the use of ECMPS, especially for CEMS data. Some commenters requested an additional rulemaking on the specific data elements to be collected. There were some concerns raised about the ERT given experience during the 2010 ICR process during the development of this rule.

Response: We recognize that emissions reporting for continuously measured pollutants (SO_2, NO_X, etc.) and for periodically measured pollutants (PM, HAP metals, etc.) have different data demands. We recognize that minor revisions of the ECMPS will fulfill our data needs for most continuously measured pollutants and we will make these modifications for receipt of the additional CEMS data. We also recognize the need for substantial modifications to the ECMPS to accommodate the data needs for periodically measured pollutants and certain CEMS data such as PM CEMS data and possibly HAP metals CEMS data. Although major modifications of the ECMPS would be required for periodic compliance tests by isokinetic and instrumental test methods (as well as certain types of CEMS), only minor revisions are required of the ERT to receive these tests. We are implementing the changes in the ERT that are required to provide the software tools to implement the delivery of these performance test data to us.

The electronic submission of compliance test reports to us through the Central Data Exchange (CDX) is not solely for the purpose of developing improved emissions factors as some commenters assert. Although populating WebFIRE will allow us to improve emissions factors, we intend to use data stored in WebFIRE as the primary location for compliance test reports for use by regulatory authorities. The electronic submission of compliance test reports is a continuation of our efforts to bring the submission and sharing of environmental data into the modern age. The storage of this compliance data in our WebFIRE provides a convenient location which is already used to store source test data.

As federal and state and local agencies' data systems mature, information provided through the ERT will be used to populate these data systems. We are currently upgrading the AIRS Facility System and expect to replace manually entered information with electronic population from the ERT. We are also working with several state and local agencies to adopt the use of the ERT for delivery of compliance test reports. The ERT is also much improved since the version used during the 2010 ICR process, and there is no expectation that the information to be reported under this final rule will be as extensive as some of the data reported for the 2010 ICR purposes.

We disagree that a separate and independent regulatory action is required to implement electronic reporting for selected regulated sources. Each of these regulatory actions for selected source categories provides ample notice and the opportunity for individuals to provide comment. We also disagree that the system to receive the compliance data must be operational prior to establishing the requirement for regulated sources to submit compliance data electronically. We are on track to have the capability to receive electronic compliance tests through our CDX in sufficient time to receive all utility source test reports required by this final rule.

We do plan a separate and independent regulatory action to implement electronic reporting for regulated entities which are covered by past and future rules. Although we have provided draft procedures for the development of emissions factors, that effort is an ancillary effort to the electronic delivery of compliance test reports. It is our intention to convert to the electronic delivery and storage of all air emissions compliance source test data. With this transition, we believe this valuable information will be more readily available not only for compliance purposes but also for a variety of other uses.

I. Emissions Averaging

Comment: In response to our request for comments on the suitability of emissions averaging and need for a discount factor, we received a range of suggestions, including requests for clarification regarding eligibility, points for and against the need for a discount factor, and suggestions to ease implementation.

Response: We are finalizing that owners and operators of existing affected sources may demonstrate compliance by emissions averaging for EGUs at the affected source that are within a single subcategory and that rely on emissions testing as the compliance demonstration method. See section VI of thie preamble for a fuller discussion.

J. LEE Criteria

Comment: A commenter supported the LEE provisions but believed one of the LEE eligibility criteria should set at 29.0 lb/year, rather than 22.0 lb/year. The commenter suggested 29.0 lb/year to be an equally reasonable cut point, especially since that value matches the low mass emitter Hg monitoring cutoff in CAMR and the low mass emitter Hg monitoring cutoff that several states have adopted, including Illinois, 35 Ill. Admin. Code section 225.240(a)(4). (*See, e.g.,* Colorado (5 Colo. Code Regs. section 1 00 1–8, Reg. No.6, part B, Section VIII.B.l0); Michigan (Mich. Admin. Code R. 336.2160); Montana (Mont. Admin. R. 17.8771(12))). Further, a LEE cutoff of 29.0 lb would eliminate conflicts and confusion with low mass emitter provisions in existing state Hg programs and significantly reduce compliance costs and burdens for the additional qualifying units without adversely affecting compliance assurance with the EGU NESHAP Hg emission limits or materially increasing the number of potential qualifying LEEs. Given the many other costly burdens that the rule would impose, the benefit of LEE to a qualifying unit is not insignificant.

Response: The Agency reviewed the commenter's suggestions, and one of the LEE eligibility criteria in the rule has been revised from 22.0 to 29.0 lb of Hg per year. The Agency finds the result of consistency with existing state regulations outweighs the two percent difference in nationwide Hg mass emissions, from 5 percent to 7 percent, for LEE eligibility.

VIII. Background Information on the NSPS

A. What is the statutory authority for this final NSPS?

New source performance standards implement CAA section 111(b), and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. Section 111 of the CAA requires that NSPS reflect the application of the best system of emissions reductions which (taking into consideration the cost of achieving such emissions reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. The level of control prescribed by CAA section 111 historically has been referred to as ''Best Demonstrated Technology'' or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that ''best systems'' may or may not be ''technology,'' the EPA is now using the term ''best system of emission reduction'' or BSER. As was done previously in analyzing BDT, the EPA uses available information and considers the emission reductions and incremental costs for different systems available at reasonable cost. Then, the EPA determines the appropriate emission limits representative of BSER. Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

B. What is the regulatory authority for the final rule?

The current standards for steam generating units are contained in the NSPS for EGUs (40 CFR part 60, subpart Da), industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db), and small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc).

The NSPS for EGUs (40 CFR part 60, subpart Da) were originally promulgated on June 11, 1979 (44 FR 33580) and apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS for EGUs also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system. The most recent significant amendments to emission standards under 40 CFR part 60, subpart Da, were promulgated in 2006 (71 FR 9866) resulting in new PM, SO_2, and NOP_2 limitations for 40 CFR part 60, subpart Da units.

The NSPS for industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Db) apply to units for which construction, modification, or reconstruction commenced after June 19, 1984, that have a heat input capacity greater than 29 MW (100 MMBtu/h). Those standards were originally promulgated on November 25, 1986 (51 FR 42768) and also have been amended since the original promulgation to reflect changes in BSER for these sources.

The NSPS for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc) were originally promulgated on September 12, 1990 (55 FR 37674) and apply to units with a maximum heat input capacity greater than or equal to 2.9 MW (10 MMBtu/h) but less than 29 MW (100 MMBtu/h). Those standards apply to units that commenced construction, reconstruction, or modification after June 9, 1989.

IX. Summary of the Final NSPS

The final rule amends the emission standards for SO_2, NOP_2, and PM in 40 CFR part 60, subpart Da. Only those units that begin construction, modification, or reconstruction after May 3, 2011, will be affected by the final rule. Compliance with the emission limits of the final rule will be determined using testing, monitoring, and other compliance provisions similar to those set forth in the existing standards. In addition to the emissions limits contained in the final rule, we also are including several technical clarifications and corrections to existing provisions of the subparts.

A. What are the requirements for new EGUs (40 CFR part 60, subpart Da)?

The filterable PM emissions standard for new and reconstructed EGUs is 11 nanograms per joule (ng/J) (0.090 pound per megawatt hour (lb/MWh)) gross energy output regardless of the type of fuel burned. The PM emissions standard for modified EGUs is essentially equivalent to the existing requirements of 13 ng/J (0.015 lb/MWh) heat input regardless of the type of fuel burned. Compliance with this emission limit can be determined using testing, monitoring, and other compliance provisions similar to those for PM standards set forth in the existing rule. While not required, PM CEMS may be used as an alternative method to demonstrate continuous compliance and as an alternative to opacity and parameter monitoring requirements.

The SO_2 emission limit for new and reconstructed EGUs is 130 ng/J (1.0 lb/MWh) gross energy output or 97 percent reduction regardless of the type of fuel burned with one exception. The EPA neither proposed to amended the SO_2 standard for coal refuse-fired EGUs, not reopened the issue of whether coal refuse-fired EGUs is an appropriate subcategory, and, therefore, that emissions standard is unchanged. The SO_2 emission limit for modified EGUs burning any fuel is 180 ng/J (1.4 lb/MWh) gross energy output or 90 percent reduction. Compliance with the SO_2 emission limit is determined on a 30-boiler operating day rolling average basis using a CEMS to measure SO_2 emissions and following the compliance provisions in the proposed rule.

The NO_X emission limit for new and reconstructed EGUs is 88 ng/J (0.70 lb/MWh) gross energy output regardless of the type of fuel burned with one exception. The exception is that for new and reconstructed EGUs that burn over 75 percent coal refuse (by heat input), the NO_X emission limit is 110 ng/J (0.85 lb/MWh) gross energy output. The NO_X limit for modified EGUs is 140 ng/J (1.1 lb/MWh) gross energy output regardless of the type of fuel burned in the unit. Compliance with this emission limit is determined on a 30-boiler operating day rolling average basis using testing, monitoring, and other compliance provisions similar to those in the proposed rule.

As an alternative to the NO_X standard, owners/operators of new and reconstructed EGUs may elect to comply with a combined NO_X/CO standard of 140 ng/J (1.1 lb/MWh) with one exception. The exception is that for new and reconstructed EGUs that burn over 75 percent coal refuse (by heat input) on an annual basis, the NO_X/CO emission limit is 160 ng/J (1.3 lb/MWh) gross energy output. Finally, owners/operators of modified EGUs may elect to comply with a combined NO_X/CO standard of 190 ng/J (1.5 lb/MWh).

B. Additional Amendments

See the Response to Comments document.

X. Summary of Significant Changes Since Proposal

A. Emission Limits

The proposal included a combined (filterable plus condensable) PM standard. The final standard is based only on filterable PM. No standard is being established for condensable PM. The rationale for this is set forth in the Response to Comments (RTC) document for this final rule (the NSPS Final Rule RTC).

The proposal requested comment on whether the final standard should include a stand-alone NO_X standard or a combined NO_X/CO standard. In response to comments we received and our own further evaluation of the situation, the final standard includes a stand-alone NO_X standard and an optional, but not required, combined NO_X/CO standard as an alternative to the amended NO_X standard. Again, our full rationale for this is set forth in the NSPS Final Rule RTC. The proposal also included a request for comment on whether the standard should be based on gross or net output. In response to comments we received and our own further evaluation of the situation, the final standards are based on an amended definition of gross output with an optional net output-based standard. This too is addressed more fully in the NSPS Final Rule RTC.

The proposal included alternate emission standards for commercial demonstration projects. Proposed commercial demonstrations included pressurized fluidized beds, multi-pollutant control technologies, and advanced combustion controls. The final rule includes the commercial demonstration permit exemption for pressurized fluidized beds and multi-pollutant control technologies, but not advanced combustion controls. Advanced combustion controls are applicable to existing facilities and the exemption is not necessary to further the development of the technology.

B. Requirements During Startup, Shutdown, and Malfunction

For startup and shutdown, the requirements for PM have changed since proposal. For periods of startup and shutdown, the EPA is finalizing work practice standards for PM in lieu of numeric emission limits. Emissions incurred during periods of startup and shutdown for PM are not used in demonstrations of compliance with the 30-boiler operating day rolling average period applicable for numeric emission standards.

XI. Public Comments and Responses to the Proposed NSPS

See the Response to Comments document.

XII. Impacts of the Final Rule

The EPA anticipates significant public health and environmental benefits from the rule as a direct result of the substantial reduction in the emissions of several pollutants, including SO_2, Hg, acid gases and fine particles and metals. For example, exposure to Hg can damage the developing nervous system, which can impair children's ability to think and learn, and fine particles can cause adverse cardiovascular effects. Further, reducing Hg deposition to ecosystems will benefit wildlife including fish, birds, and mammals. Fish and fish-eating birds, such as the common loon, and mammals suffer reproductive, survival, and behavioral impairments due to mercury exposure. These effects have also been observed in insect-eating and wading birds, including egrets and white ibis. Reductions of emissions targeted by this rule also will slow acidification and eutrophication of water bodies.

Additionally, the EPA anticipates significant non-health, non-ecological benefits from this rule. The fine particle and SO_2 emission reductions achieved by this rule will improve visibility, which is especially important for our national parks. Emissions reductions from this rule will also avoid an estimated $360 million (in $2007) of climate-related costs, such as agricultural productivity and property damage from increased flood risks.

A. What are the air impacts?

The EPA anticipates significant emission reductions under the final rule from coal-fired EGUs, which are of particular interest due to their share of total power sector emissions. In 2015, annual HCl emissions are projected to be reduced by 88 percent, Hg emissions reduced by 75 percent, and $PM_{2.5}$ emissions reduced by 19 percent from coal-fired EGUs greater than 25 MW. In addition, the EPA projects SO_2 emission reductions of 41 percent, and annual CO_2 reductions of 1 percent from coal-fired EGUs greater than 25 MW by 2015, relative to the base case. *See* Table 7.

TABLE 7—SUMMARY OF EMISSION REDUCTIONS FROM COAL-FIRED EGUS GREATER THAN 25 MW (TPY)

	SO_2 (million tons)	NO_X (million tons)	Mercury (tons)	HCl (thousand tons)	$PM_{2.5}$ (thousand tons)	CO_2 (million metric tonnes)
Base Case	3.3	1.7	27	45	270	1,906
MATS	1.9	1.7	7	6	218	1,882
Change	−1.4	0.0	−20	−40	−52	−23

Note: Numbers may not add due to rounding.

The reductions in this table do not account for reductions in other HAP which will occur as a result of this rule. For instance, the fine particulate reductions presented above only partly reflect reductions in many heavy metal particulates, and the HCl reductions above only partly reflect reductions of all acid gases. This rule will also result in additional HAP reductions from oil-fired EGUs, which are covered by the rule but are not included in the EPA's analysis of emission reductions.

B. What are the energy impacts?

The EPA projects that approximately 4.7 GW of coal-fired generation (less than 2 percent of all coal-fired capacity and 0.5 percent of total generation capacity in 2015) may be uneconomic to maintain and may be removed from operation by 2015. These units are predominantly smaller, less frequently used, and are dispersed throughout the country. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to make further investments in these facilities and keep these units operational.

The final rule has other important energy market implications. Average nationwide retail electricity prices are projected to increase in the contiguous U.S. by 3.1 percent in 2015. The average delivered coal price is projected to increase by less than 2 percent in 2015 as a result of shifts within and across coal types. The EPA also projects that electric power sector-delivered natural gas prices will increase by between 0.3 and 0.6 percent over the 2015 to 2030 timeframe, on average, and that natural gas use for electricity generation will increase by less than 200 billion cubic feet (BCF) in 2015. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 10 million tons in 2015 from base case levels, which is about 1 percent of total coal produced for the electric power sector in that year.

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 base case and policy case in which the sector pursues pollution control approaches to meet the MATS emission standards. In simple terms, these costs are the resource costs of direct power industry expenditures to comply with the EPA's requirements.

The EPA projects that the annual incremental compliance cost of MATS is $9.6 billion in 2015 ($2007). The annualized incremental cost is the projected additional cost of complying with the rule in the year analyzed, and includes the amortized cost of capital investment and the ongoing costs of operating additional pollution controls, needed new capacity, shifts between or amongst various fuels, and other actions associated with compliance.

The total incremental compliance cost includes compliance costs modeled in IPM of $9.4 billion, costs modeled outside of IPM for oil-fired EGUs of $56 million, and monitoring, reporting, and recordkeeping costs of $158 million.

D. What are the economic impacts?

For this final rule, EPA analyzed the costs using the IPM. The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for a variety of HAP and other pollutants throughout the contiguous U.S. for the entire power system.

Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.*

The EPA performed a screening analysis for impacts on small entities by comparing compliance costs to sales/revenues (*e.g.*, sales and revenue tests). The EPA's analysis can be found in Chapter 7 of the RIA for this rule. The EPA has also prepared a Final Regulatory Flexibility Analysis (FRFA) that discusses alternative regulatory or policy options that minimize the rule's small entity impacts.

Although a stand-alone analysis of employment impacts is not included in a standard cost-benefit analysis, the current economic climate has led to heightened concerns about potential job impacts. Executive Order 13563 specifically states that our ''regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and *job creation*'' (emphasis added).

Under conditions of full employment, it is conventional to assume that regulations will merely shift jobs from one sector to another, without having a material effect on employment levels. Potential employment effects are of greater concern in the current economic climate, with high levels of employment, because of the risk that displaced workers may not find alternative jobs. In addition, regulations that result in firms hiring workers, in order to ensure compliance, may have a positive effect on employment.

During sustained periods of excess unemployment, the opportunity cost of labor required by regulated sectors to bring their facilities into compliance with an environmental regulation may be lower than it would be during a period of full employment (particularly if regulated industries employ otherwise idled labor to design, fabricate, or install the pollution control equipment required under this final rule). Consistent with EO 13563, the EPA includes estimates of job impacts associated with the final rule. In the electricity sector, the EPA estimates that the net employment effect will range from −15,000 to +30,000 jobs, with a central estimate of +8,000. The EPA also presents an estimate of short-term employment effects as a result of increased demand for pollution control equipment.

The results of this analysis, found in Chapter 6 of the RIA, indicate that the final rule has the potential to provide increases in short-term employment in the environmental industry, primarily driven by the high demand for new pollution control equipment. Overall, the results suggest that the final rule could support a net of roughly 46,000 job years[355] in direct employment impacts in 2015.

There are other employment effects that cannot be estimated quantitatively at this time. The employment gains related to the new pollution controls are likely to be tempered by some losses due to certain coal retirements. On the other hand, some of those workers who lose their jobs due to plant retirements could find alternative employment operating the replacement electricity generating equipment or new pollution controls at nearby units. Finally, job losses due to reduced coal demand may be offset by job gains due to increased natural gas demand, potentially resulting in a positive net change in employment due to fuel demand changes.

The basic approach to estimate these employment impacts involved using IPM projections from the final rule analysis, in particular the amount of existing coal-fired capacity that is projected to be retrofit with pollution control technologies. These data, along with data on labor and resource needs of new pollution controls and labor productivity from engineering studies and secondary sources, are used to estimate employment impacts for the pollution control industry in 2015. For more information, please refer to Chapter 6 and appendix 6B in the RIA.

The EPA relied on Morgenstern, *et al.,* (2002), to identify three economic mechanisms by which pollution abatement activities can influence jobs in the regulated sector separately from the short-term employment effects:

- Higher production costs raise market prices, higher prices reduce consumption, and employment within an industry falls (''demand effect'');
- Pollution abatement activities require additional labor services to produce the same level of output (''cost effect''); and
- Post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) (''factor-shift effect'').

Using plant-level Census information between the years 1979 and 1991,

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[355] Numbers of job years are not the same as numbers of individual jobs, but represents the amount of work that can be performed by the equivalent of one full-time individual for a year (or FTE). For example, 25 job years may be equivalent to five full-time workers for five years, 25 full-time workers for one year, or one full-time worker for 25 years.

Morgenstern,*et al.,* estimate the size of each effect for four polluting and regulated industries (petroleum, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million spent on pollution abatement results in a small net increase of 1.55 jobs; the estimated effect is not a statistically different from zero. As a result, the authors conclude that increases in pollution abatement expenditures may increase employment in the relevant sectors and do not necessarily cause economically significant employment changes. The conclusion is similar to that of Berman and Bui (2001) who found that increased air quality regulation in Los Angeles did not cause large employment changes.[356] For more information, please refer to Chapter 6 of the RIA for this final rule.[357]

In the directly affected sector, the EPA estimates that the net employment effect will range from −15,000 to +30,000 jobs, with a central estimate of +8,000. The ranges of job effects for the electricity sector, as calculated using the Morgenstern,*et al.,* approach are listed in Table 8.

TABLE 8—RANGE OF JOB EFFECTS FOR THE ELECTRICITY SECTOR

	Estimates using Morgenstern, *et al.,* (2001)			
	Demand effect	Cost effect	Factor shift effect	Net effect
Change in Full-Time Jobs per Million Dollars of Environmental Expenditure [a].	−3.56	2.42	2.68	1.55.
Standard Error	2.03	0.83	1.35	2.24.
EPA estimate for Final Rule [b]	−39,000 to +2,000	+4,000 to +21,000	+200 to +27,000	−15,000 to +30,000.

[a] Expressed in 1987 dollars. *See* footnote a from Table 6–2 of the RIA for inflation adjustment factor used in the analysis.

[b] According to the 2007 Economic Census, the electric power generation, transmission and distribution sector (NAICS 2211) had approximately 510,000 paid employees.

The EPA recognizes there may be other job effects that are not considered in the Morgenstern,*et al.,* study. Although EPA has considered some economy-wide changes, we do not have sufficient information to quantify other job effects associated with this rule.

E. What are the benefits of this final rule?

1. Benefits of Reducing HAP Emissions

a. Human Health and Environmental Effects Due to Exposure to MeHg. In this section, we provide a qualitative description of human health and environmental effects due to exposure to MeHg. The NAS Study (NRC, 2000) provides a thorough review of the effects of MeHg on human health. Many of the peer-reviewed articles cited in this section are publications originally cited in the NAS Study. In addition, the EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NAS in 2000.

b. Neurologic Effects of Exposure to MeHg. In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and concluded that they are appropriate for establishing an RfD (NRC, 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS Study (NRC, 2000) noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended neurodevelopmental endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: ‘‘The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school.’’

c. Cardiovascular Impacts of Exposure to MeHg. The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NAS Study concluded that ‘‘Although the data base is not as extensive for cardiovascular effects as it is for other end points (*i.e.*, neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals.’’ The report also stated that ‘‘additional studies are needed to better characterize the effect of MeHg exposure on blood pressure and cardiovascular function at various stages of life.’’

Additional cardiovascular studies have been published since 2000. The EPA did not develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail Hg levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

d. Genotoxic Effects of Exposure to MeHg. The Mercury Study noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS Study indicated that evidence that human exposure to MeHg causes genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil (Amorim*et al.,* 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes, as well as effects on chromosomes. Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those

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[356] For alternative views in economic journals, see Henderson (1996) and Greenstone (2002).

[357] It should be noted that if more labor must be used to produce a given amount of output, then this implies a decrease in labor productivity. A decrease in labor productivity will cause a short-run aggregate supply curve to shift to the left, and businesses will produce less, all other things being equal.

seen in the populations studied in the Faroe Islands and Republic of Seychelles.

e. Immunotoxic Effects to Exposure to MeHg. Although exposure to some forms of Hg can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000).

f. Other Hg-Related Human Toxicity Data. Based on limited human and animal data, MeHg is classified as a ''possible'' human carcinogen by the International Agency for Research on Cancer (IARC, 1994) and in IRIS (USEPA, 2002). The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between Hg exposure and overall cancer incidence, although a few studies have shown an association between Hg exposure and specific types of cancer incidence (*e.g.,* acute leukemia and liver cancer) (NAS, 2000).

Some evidence of reproductive and renal toxicity in humans from MeHg exposure exists. However, overall, human data regarding reproductive, renal, and hematological toxicity from MeHg are very limited and are based on studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

g. Ecological Effects of Hg. Deposition of Hg to watersheds can also have an impact on ecosystems and wildlife. Mercury contamination is present in all environmental media, with aquatic systems experiencing the greatest exposures due to bioaccumulation. Bioaccumulation refers to the net uptake of a contaminant from all possible pathways and includes the accumulation that may occur by direct exposure to contaminated media as well as uptake from food.

A review of the literature on effects of Hg on fish [358] reports results for numerous species including trout, bass (large and smallmouth), northern pike, carp, walleye, salmon, and others from laboratory and field studies. The effects of MeHg in fish are reproductive in nature. Although we cannot determine at this time whether these reproductive deficits are affecting fish populations across the U.S. it should be noted that it would seem reasonable that over time reproductive deficits would have an effect on populations.

Mercury also affects avian species. In previous reports [359] much of the focus has been on large piscivorous species, in particular the common loon. According to Evers,*et al.,* significant adverse effects from Hg on breeding loons have been found to occur, including behavioral (reduced nest-sitting), physiological (flight feather asymmetry) and reproductive (chicks fledged/territorial pair) effects and reduced survival.[360] Additionally, Evers, *et al.,* (*see* footnote 5), believe that the weight of evidence indicates that population-level effects occur in parts of Maine and New Hampshire, and potentially in broad areas of the loon's range.

Recently, attention has turned to other piscivorous species such as the white ibis and great snowy egret. These wading birds have a very wide diet including crayfish, crabs, snails, insects and frogs. White ibis have been observed to have decreased foraging efficiency[361] and have been shown to exhibit decreased reproductive success and altered pair behavior.[362] In egrets, Hg has been implicated in the decline of the species in south Florida,[363] and Hoffman[364] has shown that egrets exhibit liver and possibly kidney effects. Although ibises and egrets are most abundant in coastal areas and these studies were conducted in south Florida and Nevada, the ranges of ibises and egrets extend to a large portion of the U.S.

Insectivorous birds have also been shown to suffer adverse effects due to Hg exposure. Songbirds such as Bicknell's thrush, tree swallows, and the great tit have shown reduced reproduction, survival, and changes in singing behavior. Exposed tree swallows produced fewer fledglings,[365] had lower survival rates,[366] and had compromised immune competence.[367] The great tit has exhibited reduced singing behavior and smaller song repertoire in areas of high contamination.[368]

In mammals, adverse effects have been observed in mink and river otter, both fish eating species. For otter from Maine and Vermont, maximum concentrations of Hg in fur nearly equal or exceed a level associated with mortality and concentration in liver for mink in Massachusetts/Connecticut and the levels in fur from mink in Maine exceed concentrations associated with acute mortality.[369] Adverse sublethal effects may be associated with lower Hg concentrations and consequently may be more widespread than potential acute effects. These effects may include increased activity, poorer maze performance, abnormal startle reflex, and impaired escape and avoidance behavior.[370]

h. Methodology for Partial Hg Benefits Estimation. The EPA has conducted a national-scale analysis of the benefits to recreational anglers of avoided IQ loss related to reductions of Hg emissions

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[358] Crump, KL, and Trudeau, VL. Mercury-induced reproductive impairment in fish. Environmental Toxicology and Chemistry. Vol. 28, No. 5, 2009.

[359] U.S. Environmental Protection Agency (EPA). 1997. Mercury Study Report to Congress. Volume V: Health Effects of Mercury and Mercury Compounds. EPA–452/R–97–007. U.S. EPA Office of Air Quality Planning and Standards, and Office of Research and Development; U.S. Environmental Protection Agency (U.S. EPA). 2005. *Regulatory Impact Analysis of the Final Clean Air Mercury Rule.* Research Triangle Park, NC., March; EPA report no. EPA–452/R–05–003. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/mercury_ria_final.pdf.*

[360] Evers, DC, Savoy, LJ, DeSorbo, CR, Yates, DE, Hanson, W, Taylor, KM, Siegel, LS, Cooley, JH, Jr., Bank, MS, Major, A, Munney, K, Mower, BF, Vogel, HS, Schoch, N, Pokras, M, Goodale, MW, Fair, J. Adverse effects from environmental mercury loads on breeding common loons. Ecotoxicology. 17:69–81, 2008; Mitro, MG, Evers, DC, Meyer, MW, and Piper, WH. Common loon survival rates and mercury in New England and Wisconsin. Journal of Wildlife Management. 72(3): 665–673, 2008.

[361] Adams, EM, and Frederick, PC. Effects of methylmercury and spatial complexity on foraging behavior and foraging efficiency in juvenile white ibises (Eudocimus albus). Environmental Toxicology and Chemistry. Vol 27, No. 8, 2008.

[362] Frederick, P, and Jayasena, N. Altered pairing behavior and reproductive success in white ibises exposed to environmentally relevant concentrations of methylmercury. Proceedings of The Royal Society B. doi: 10–1098, 2010.

[363] Sepulveda, MS, Frederick, PC, Spalding, MG, and Williams, GE, Jr. Mercury contamination in free-ranging great egret nestlings (Ardea albus) from southern Florida, USA. Environmental Toxicology and Chemistry. Vol. 18, No. 5, 1999.

[364] Hoffman, DJ, Henny, CJ, Hill, EF, Grover, RA, Kaiser, JL, Stebbins, KR. Mercury and drought along the lower Carson River, Nevada: III. Effects on blood and organ biochemistry and histopathology of snowy egrets and black-crowned night-herons on Lahontan Reservoir, 2002–2006. Journal of Toxicology and Environmental Health, Part A. 72: 20, 1223–1241, 2009.

[365] Brasso, RL, and Cristol, DA. Effects of mercury exposure in the reproductive success of tree swallows (Tachycineta bicolor). Ecotoxicology. 17:133–141, 2008.

[366] Hallinger, KK, Cornell, KL, Brasso, RL, and Cristol, DA. Mercury exposure and survival in free-living tree swallows (Tachycineta bicolor). Ecotoxicology. Doi: 10.1007/s10646–010–0554–4, 2010.

[367] Hawley, DM, Hallinger, KK, Cristol, DA. Compromised immune competence in free-living tree swallows exposed to mercury. Ecotoxicology. 18:499–503, 2009.

[368] Gorissen, L, Snoeijs, T, Van Duyse, E, and Eens, M. Heavy metal pollution affects dawn singing behavior in a small passerine bird. Oecologia. 145: 540–509, 2005.

[369] Yates, DE, Mayack, DT, Munney, K, Evers DC, Major, A, Kaur, T, and Taylor, RJ. Mercury levels in mink (Mustela vison) and river otter (Lonra canadensis) from northeastern North America. Ecotoxicology. 14, 263–274, 2005.

[370] Scheuhammer, AM, Meyer MW, Sandheinrich, MB, and Murray, MW. Effects of environmental methylmercury on the health of wild birds, mammals, and fish. Ambio. Vol.36, No.1, 2007.

and subsequent deposition that will be achieved by this rule. Because the primary measurable health effect of concern—developmental neurological abnormalities in children—occurs as a result of in-utero exposures to Hg, the specific population of interest in this case is prenatally exposed children. To identify and estimate the size of this exposed population, the benefits analysis focused on pregnant women in freshwater recreational angler households. Estimating Hg exposures for this exposure pathway and population of interest requires three main components: (1) The size of the exposed population of interest (annual number of pregnant women in freshwater angler households during the year), (2) the average concentration of MeHg in noncommercial freshwater fish filets consumed, and (3) the average daily consumption rate of noncommercial freshwater fish. The Hg concentrations of fish in the waterbodies where the fish are caught are modeled using Mercury Maps to project the decline in concentrations due to the rule. To approximate the percentage of freshwater fishing trips (and exposed individuals) from each Census tract matched to each waterbody type, the EPA used state-level averages. These averages were calculated for each state, based on the portion of residents' freshwater fishing trips that are to each waterbody type, based on 2001 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation (FHWAR) data.

Data from the 1994 National Survey on Recreation and the Environment (NSRE) were used to approximate the percentage of freshwater fishing trips (and exposed individuals) matched to different distances from anglers' residential location.

To determine an appropriate daily fish consumption rate for the analysis, the EPA conducted an extensive review of existing literature characterizing self-caught freshwater fish consumption. Based on this review, it was decided that the ingestion rates for recreational freshwater fishers, specified as ''recommended'' in the EPA's ''Environmental Exposure Factors Handbook'' (EPA, 1997), represented the most appropriate values to use in this analysis.

Estimating the IQ decrements in children that result from mothers' prenatal ingestion of Hg from fish required two steps. First, based on the estimated average daily maternal ingestion rate, the expected Hg concentration in the hair of exposed pregnant women was estimated. Second, to estimate the expected IQ decrement in offspring, the following dose-response relationship was developed based on the summary findings reported in Axelrad *et al.,* (2007).

The valuation approach used to assess monetary losses due to IQ decrements is based on an approach applied in previous EPA analyses (EPA, 2008). The approach expresses the potential loss to an affected individual resulting from IQ decrements in terms of foregone future earnings (net of changes in education costs) for that individual.

The estimate for ''Present Value of Lifetime Earnings'' is derived using earnings and labor force participation rate data from the Bureau of Labor Statistics 2006 Current Population Survey. Estimates of the average effect of a 1-point increase in IQ on lifetime earnings range from a 1.76 percent increase (Schwartz, 1994) to a 2.379 percent increase (Salkever, 1995). The percentage increases in the two studies reflect both the direct impact of IQ on hourly wages and indirect effects on annual earnings as the result of additional schooling and increased labor force participation. The estimate for years of additional schooling is based on Schwartz (1994), who reports an increase of 0.131 years of schooling per IQ point.

In addition to this positive net effect on earnings, an increase in IQ is also assumed to have a positive effect on the amount of time spent in school and on associated costs. To incorporate (1) uncertainty regarding the size of the percentage change in future earnings and (2) different assumptions regarding the discount rate, the resulting value estimates for the average net loss per IQ point decrement are expressed as a range. Assuming a 3 percent discount rate, value IQ ranges from $8,013 (using the Schwartz estimates) to $11,859 (using the Salkever estimates) in increased earnings per year per 1-point IQ increase. With a 7 percent discount rate assumption, the value IQ estimates range from $893 to $1,958 in increased earnings per year per 1-point IQ increase.

The EPA analyzed the aggregate national IQ and present-value loss estimates for two base case and three emission control scenarios. The highest losses are estimated for the 2005 base case. For the population of prenatally exposed children included in the analysis (almost 240,000), Hg exposures under baseline conditions during the year 2005 are estimated to have resulted in more than 25,500 IQ points lost. Assuming a 3 percent discount rate, the present-year value of these losses ranges from $204.8 million to $292.5 million nationally.[371] These losses represent expected present value of declines in future net earnings over the entire lifetimes of the children who are prenatally exposed during the year 2005. With a 7 percent discount rate, the present-year value range is considerably lower: $22.8 million to $50.0 million.

For this rule, the EPA generated estimates of aggregate nationwide benefits associated with reductions in Hg exposures and resulting reductions in IQ losses. Most importantly, the benefits of the 2016 MATS scenario (relative to the 2016 base case) are estimated to range between $4 million and $6 million (assuming a 3 percent discount rate), because of an estimated 511 point reduction in IQ losses. The EPA recognizes that these calculated benefits are a small subset of the benefits of reducing Hg emissions.

2. Health and Welfare Co-Benefits

Emission controls installed to meet the requirements of this rule will generate co-benefits by reducing criteria pollutants including $PM_{2.5}$ and SO_2, as well as CO_2. For this rule, we were only able to estimate the mortality benefits of $PM_{2.5}$ reductions due to changes in emissions of SO_2 and direct $PM_{2.5}$ and climate benefits resulting from CO_2 reductions. Additional co-benefits may result from decreases in $PM_{2.5}$ morbidity impacts, decreases in sulfur deposition and direct health effects of SO_2, and improvements in visibility in national parks and wilderness areas. Total co-benefits may be higher than the partial estimates of co-benefits provided here. Our best estimate of the monetized health and climate co-benefits of this rule in 2016 at a 3 percent discount rate are $37 billion to $90 billion or $33 billion to $81 billion at a 7 percent discount rate (2007$). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower health co-benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[372]

a. Human Health Co-Benefits. To estimate the human health co-benefits of this rule, the EPA used benefit-per-ton

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[371] Monetized benefits estimates are for an immediate change in MeHg levels in fish. If a lag in the response of MeHg levels in fish were assumed, the monetized benefits could be significantly lower, depending on the length of the lag and the discount rate used. As noted in the discussion of the Mercury Maps modeling, the relationship between deposition and fish tissue MeHg is proportional in equilibrium, but the Mercury Maps approach does not provide any information on the time lag of response.

[372] Roman, *et al.,* 2008. Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S. Environ. Sci. Technol., 42, 7, 2268–2274.

factors to quantify the changes in $PM_{2.5}$-related health impacts and monetized benefits based on changes in SO_2 and direct $PM_{2.5}$ emissions. These benefit-per-ton factors were based on an interim baseline and policy scenario for which full-scale ambient air quality modeling and air quality-based human health benefits assessments were performed. This general approach and methodology is laid out in Fann, *et al.,* (2009),[373] but for this rule the air quality modeling used a better spatial representation of the emission changes from EGUs. Using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. For more details on the creation of the benefit-per-ton factors and their application to emission reductions under this rule, please refer to the RIA for this rule in the docket.

Table 9 presents the estimates of reduced annual incidence of $PM_{2.5}$-related health effects in 2016 resulting from this rule. Table 10 presents the estimated annual monetary value of the reduced incidence of quantified health endpoints in 2016 resulting from this rule.

The reduction in premature fatalities each year accounts for between 93 and 97 percent of the estimated health co-benefits that were monetized.

TABLE 9—ESTIMATED REDUCTIONS IN INCIDENCE OF $PM_{2.5}$-RELATED HEALTH EFFECTS IN 2016[a]

Health effect	Number of reduced cases
Adult Premature Mortality	
Pope *et al.,* (2002) (age >30)	4,200. (1,200 to 7,200).
Laden *et al.,* (2006) (age >25)	11,000. (5,000 to 17,000).
Infant Premature Mortality (<1 year)	20. (−22 to 61).
Chronic Bronchitis	2,800. (88 to 5,600).
Non-fatal heart attacks (age >18)	4,700. (1,200 to 8,300).
Hospital admissions—respiratory (all ages)	830. (330 to 1,300).
Hospital admissions—cardiovascular (age >18)	1,800. (1,200 to 2,200).
Emergency room visits for asthma (age <18)	3,100. (1,600 to 4,700).
Acute bronchitis (age 8–12)	6,300. (−1,400 to 14,000).
Lower respiratory symptoms (age 7–14)	80,000. (31,000 to 130,000).
Upper respiratory symptoms (asthmatics age 9–11)	60,000. (11,000 to 110,000).
Asthma exacerbation (asthmatics 6–18)	130,000. (4,500 to 450,000).
Lost work days (ages 18–65)	540,000. (460,000 to 620,000).
Minor restricted-activity days (ages 18–65)	3,200,000. (2,600,000 to 3,800,000).

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

TABLE 10—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS IN 2016[a]

Health effect	Monetized benefits
Adult Premature Mortality	
Pope, *et al.,* (2002) (age >30):	
3% discount rate	$34. ($2.6 to $100).
7% discount rate	$30. ($2.4 to $92).
Laden, *et al.,* (2006) (age >25):	
3% discount rate	$87. ($7.5 to $250).
7% discount rate	$78. ($6.8 to $230).
Infant Premature Mortality (<1 year)	$0.2. ($−0.2 to $0.8).
Chronic Bronchitis	$1.4. ($0.1 to $6.4).
Non-fatal heart attacks (age >18):	

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[373] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. ''The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution.'' Air Qual Atmos Health (2009) 2:169–176.

TABLE 10—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF $PM_{2.5}$-RELATED HEALTH BENEFITS IN 2016[a]—Continued

Health effect	Monetized benefits
3% discount rate	$0.5. ($0.1 to $1.3).
7% discount rate	$0.4. ($0.1 to $1.0).
Hospital admissions—respiratory (all ages)	$0.01. ($0.01 to $0.02).
Hospital admissions—cardiovascular (age >18)	$0.03. (<$0.01 to $0.05).
Emergency room visits for asthma (age <18)	<$0.01.
Acute bronchitis (age 8–12)	<$0.01.
Lower respiratory symptoms (age 7–14)	<$0.01.
Upper respiratory symptoms (asthmatics age 9–11)	<$0.01.
Asthma exacerbation (asthmatics 6–18)	<$0.01.
Lost work days (ages 18–65)	$0.1. ($0.1 to $0.1).
Minor restricted-activity days (ages 18–65)	$0.2. ($0.1 to $0.3).
Monetized Health Co-Benefits	
Pope, *et al.,* (2002):	
3% discount rate	$36. ($2.8–$110).
7% discount rate	$33. ($2.5–$100).
Laden, *et al.,* (2006):	
3% discount rate	$89. ($7.7–$260).
7% discount rate	$80. ($6.9–$240).

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

It is important to note that the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. We cite two key empirical studies, one based on the American Cancer Society cohort study[374] and the other based on the extended Six Cities cohort study.[375] The analyses upon which this rule is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects, or to assign economic values even to those health and environmental outcomes that can be quantified. The uncertainties in the underlying scientific and economics literature (that may result in overestimation or underestimation of the co-benefits) are discussed in detail in the RIA. Despite these uncertainties, we believe the benefit analysis for this rule provides a reasonable indication of the expected health co-benefits of the rulemaking in future years under a set of reasonable assumptions.

When characterizing uncertainty in the PM-mortality relationship, the EPA has historically presented a sensitivity analysis applying alternate assumed thresholds in the PM concentration-response relationship. In its synthesis of the current state of the PM science, the EPA's 2009 Integrated Science Assessment for Particulate Matter concluded that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship.

In the RIA accompanying this rulemaking, rather than segmenting out impacts predicted to be associated with levels above and below a ''bright line'' threshold, the EPA includes a ''lowest measured level'' (LML) analysis that illustrates the increasing uncertainty that characterizes exposure attributed to levels of $PM_{2.5}$ below the LML of each epidemiological study used to estimate $PM_{2.5}$-related premature death. Figures provided in the RIA show the distribution of baseline exposure to $PM_{2.5}$, as well as the lowest air quality levels measured in each of the epidemiology cohort studies. This information provides a context for considering the likely portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the size of the estimated reduction in $PM_{2.5}$-related premature mortality diminishes as baseline concentrations of $PM_{2.5}$ are lowered.

Based on the modeled interim baseline which is approximately equivalent to the final baseline (*see* Appendix A of the RIA), 11 percent and 73 percent of the estimated avoided mortality impacts occur at or above an

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[374] Pope *et al.,* 2002. ''Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.'' Journal of the American Medical Association. 287:1132–1141.

[375] Laden*et al.,* 2006. ''Reduction in Fine Particulate Air Pollution and Mortality.'' American Journal of Respiratory and Critical Care Medicine. 173:667–672.

annual mean $PM_{2.5}$ level of 10 μg/m3 (the LML of the Laden*et al.,* 2006 study)or 7.5 μg/m3 (the LML of the Pope,*et al.,* 2002 study), respectively. Although the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations. A large fraction of the $PM_{2.5}$-related benefits occur below the level of the National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$ at 15 μg/m3, which was set in 2006. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations. While benefits occurring below the standard may be less certain than those occurring above the standard, EPA considers them to be legitimate components of the total benefits estimate.

It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Benefits are shown as a range from Pope, *et al.,* (2002), to Laden, *et al.,* (2006). These studies assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because there is no clear scientific evidence that would support the development of differential effects estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between directly-emitted particles (carbonaceous and crustal particles) and SO_2 emissions that form sulfate particles, based on the location of emission changes and magnitude of population exposure changes. Regardless, however, the assumption that all fine particles are equally potent in causing premature mortality adds uncertainty to the benefits estimate.

b. Non-Climate Welfare Co-Benefits. Emission controls installed to comply with the requirements specified in this rule will also generate co-benefits by improving visibility. We anticipate that improvements in visibility in Class I areas as well as residential areas where people live, work, and recreate could be substantial. Because full-scale air quality modeling was not performed for this rule, we are unable to quantify these visibility co-benefits for this rule. However, the estimated value of visibility benefits calculated from the modeled interim baseline and policy scenario was $1.1 billion (in 2007$). These visibility benefits are not included in the total co-benefits estimate of the final policy scenario used as a basis for this final rule. The distribution of emission reductions did not change substantially in the visibility regions studied, therefore visibility benefits of the final policy scenario are likely to be of a similar magnitude.

Ecosystem and other welfare effects include reduced acidification and, in the case of NO_X, eutrophication of water bodies; possible reduced nitrate contamination of drinking water; ozone vegetation damage; a reduction in the role of sulfate in Hg methylation; and reduced acid and particulate deposition that causes damages to cultural monuments, as well as soiling and other materials damage. To illustrate the important nature of benefit categories the EPA is currently unable to monetize, we discuss the potential public welfare and environmental impacts related to reductions in emissions required by this rule in the RIA, including reduced visibility impairment, reduced effects from acid deposition, reduced effects from nutrient enrichment, and reduced vegetation effects from ambient exposure to SO_2 and NO_2.

c. Climate co-benefits. This rule is expected to reduce CO_2 emissions from the electricity sector. The EPA has assigned a dollar value to reductions in CO_2 emissions using recent estimates of the ‘‘social cost of carbon’’ (SCC). The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year or the per metric ton benefit estimate relating to decreases in CO_2 emissions. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damage from increased flood risk, and the value of ecosystem services due to climate change.

The SCC estimates used in this analysis were developed through an interagency process that included the EPA and other executive branch entities, and that concluded in February 2010. We first used these SCC estimates in the benefits analysis for the final joint EPA/DOT Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule's preamble for discussion about application of the SCC (75 FR 25324; May 7, 2010). The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates.[376]

The interagency group selected four SCC values for use in regulatory analyses, which we have applied in this analysis: $5.9, $24.3, $39, and $74.4 per metric ton of CO_2 emissions in 2016, in 2007 dollars. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent, respectively. Social cost of carbon values at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the SCC from all three values at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the extremes of the SCC distribution. Low probability, high impact events are incorporated into all of the SCC values through explicit consideration of their effects in two of the three values as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high temperature outcomes, which in turn leads to higher projections of damages.

Applying the global SCC estimates using a 3 percent discount rate, we estimate the value of the climate related benefits of this rule in 2016 is $360 million (2007$), as shown in Table 11. See the RIA for more detail on the methodology used to calculate these benefits and additional estimates of climate benefits using different discount rates and the 95th percentile of the 3 percent discount rate SCC. Important limitations and uncertainties of the SCC approach are also described in the RIA.

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[376] Docket ID EPA–HQ–OAR–2009–0472–114577, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at *http://epa.gov/otaq/climate/regulations.htm.*

TABLE 11—ESTIMATED MONETARY VALUE (BILLIONS 2007$) OF PM$_{2.5}$-RELATED HEALTH BENEFITS AND CLIMATE BENEFITS IN 2016[a]

Effect	Monetized benefits
Monetized Health Co-Benefits	
Pope, *et al.,* (2002):	
3% discount rate	$36 ($2.8–$110)
7% discount rate	$33 ($2.5–$100)
Laden, *et al.,* (2006):	
3% discount rate	$89 ($7.7–$260)
7% discount rate	$80 ($6.9–$240)
Climate-related Co-Benefits (3% discount rate)	$0.36
Monetized Total Co-Benefits	
Pope, *et al.,* (2002):	
3% discount rate	$37 ($3.2–$110)
7% discount rate	$33 ($2.9–$100)
Laden, *et al.,* (2006):	
3% discount rate	$90 ($8.0–$260)
7% discount rate	$81 ($7.3–$240)

[a] Values rounded to two significant figures. Co-benefits from reducing exposure to ozone, other criteria pollutants, and HAP, as well as reducing visibility impairment and ecosystem effects are not included here.

Our best estimate for the monetized total health and climate co-benefits of this rule in 2016 at a 3 percent discount rate is between $37 billion and $90 billion or between $33 billion and $81 billion (2007$) at a 7 percent discount rate. These estimates account for the quantified health and climate benefits described in Table 11.

XIII. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under EO 12866 (58 FR 51735; October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 and any changes in response to OMB recommendations have been documented in the docket for this action. For more information on the costs and benefits for this rule, please refer to Table 2 of this preamble.

When estimating the human health benefits and compliance costs in Table 2 of this preamble, the EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. The EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, the EPA adheres to EO 13563, ''Improving Regulation and Regulatory Review,'' (76 FR 3821; January 18, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a ''regulatory system [that] * * * promote[s] predictability and reduce[s] uncertainty'' and that ''identify[ies] and use[s] the best, most innovative, and least burdensome tools for achieving regulatory ends.'' In addition, EO 13563 states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' We recognize that the utility sector faces a variety of requirements, including ones under CAA section 110(a)(2)(D) dealing with the interstate transport of emissions contributing to ozone and PM air quality problems, with coal combustion wastes, and with the implementation of CWA section 316(b). In developing today's final rule, the EPA recognizes that it needs to approach these rulemakings in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that underlie the rulemakings.

A summary of the monetized costs, benefits, and net benefits for the final rule at discount rates of 3 percent and 7 percent is in Table 2 of this preamble. For more information on the analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the OMB under the Paperwork Reduction Act, 44

U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by the EPA has been assigned EPA ICR number 2137.06.

The information collection requirements are not enforceable until OMB approves them. The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B. This final rule requires maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subpart UUUUU. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

For this rule, EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR that shows what the notification, recordkeeping, and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $3,141, and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate no more than two such occurrences for all sources subject to 40 CFR part 63, subpart UUUUU over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and record-keeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $207.6 million. This includes 700,296 labor hours per year at a total labor cost of $49.1 million per year, annualized capital costs of $81.9 million, and annual operating and maintenance costs of $76.5 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and recordkeeping. All burden estimates are in 2007 dollars and represent the most cost effective monitoring approach for affected facilities. Burden is defined at 5 CFR 1320.3(b).

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 our regulations are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act, as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business that is an electric utility producing 4 billion kilowatt-hours or less as defined by NAICS codes 221122 (fossil fuel-fired electric utility steam generating units) and 921150 (fossil fuel-fired electric utility steam generating units in Indian country); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to RFA section 603, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the Panel Report (EPA–HQ–OAR–2009–0234–2921). A summary of the Panel's recommendations is presented at 76 FR 24975.

As required by RFA section 604, we also prepared a final regulatory flexibility analysis (FRFA) for the final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA is summarized below and in the RIA.

1. Reasons Why Action Is Being Taken

In 2000, the EPA made a finding that it was appropriate and necessary to regulate coal- and oil-fired EGUs under CAA section 112 and listed EGUs pursuant to CAA section 112(c). On March 29, 2005 (70 FR 15994), the EPA published a final rule (2005 Action) that removed EGUs from the list of sources for which regulation under CAA section 112 was required. That rule was published in conjunction with a rule requiring reductions in emissions of Hg from EGUs pursuant to CAA section 111, i.e., CAMR, May 18, 2005, 70 FR 28606). The 2005 Action was vacated on February 8, 2008, by the U.S. Court of Appeals for the District of Columbia Circuit. As a result of that vacatur, CAMR was also vacated and EGUs remain on the list of sources that must be regulated under CAA section 112. This action provides the EPA's final NESHAP and NSPS for EGUs.

2. Statement of Objectives and Legal Basis for Final Rules

The MATS will protect air quality and promote public health by reducing emissions of HAP. In the December 2000 regulatory determination, the EPA made a finding that it was appropriate and necessary to regulate EGUs under CAA section 112. The February 2008 vacatur of the 2005 Action reverted the status of the rule to the December 2000 regulatory determination. Section 112(n)(1)(A) of the CAA and the 2000 determination do not differentiate between EGUs located at major versus area sources of HAP. Thus, the NESHAP for EGUs will regulate units at both major and area sources. Major sources of HAP are those that have the potential to emit at least 10 tons per year (tpy) of any one HAP or at least 25 tpy of any combination of HAP. Area sources are any stationary sources of HAP that are not major sources.

3. Summary of Issues Raised During the Public Comment Process on the IRFA

The EPA received a number of comments related to the Regulatory Flexibility Act during the public comment process. A consolidated version of the comments received is reproduced below. These comments can also be found in their entirety in the response to comment document in the docket.

Comment: Several commenters expressed concern with the SBAR panel. Some believe Small Entity Representatives (SERs) were not provided with regulatory alternatives including descriptions of significant regulatory options, differing timetables, or simplifications of compliance and reporting requirements, and subsequently were not presented with an opportunity to respond. One commenter believes the EPA's formal SBAR Panel notification and subsequent information provided by the EPA to the Panel did not include information on the potential impacts of the rule as required by CAA section 609(b)(1). Additional commenters suggested that the EPA's rulemaking schedule put pressure on the SBAR Panel through the abbreviated preparation for the Panel. Commenters also expressed concerns that the EPA did not provide participants more than cursory background information on which to base their comments. One commenter stated that the EPA did not provide deliberative materials, including draft proposed rules or discussions of regulatory alternatives, to the SBAR Panel members. One commenter stated the SBAR Panel Report does not meet the statutory obligation to recommend less burdensome alternatives. The commenter suggested the EPA panel members declined to make recommendations that went further than consideration or investigation of broad regulatory alternatives, with the exception of those recommendations in which the EPA rejected alternative interpretations of the CAA section 112 and relevant court cases. Two stated that the EPA did not respond to the concerns of the small business community, the SBA, or OMB, ignoring concerns expressed by the SER panelists. One commenter believes the EPA failed to convene required meetings and hearings with affected parties as required by law for small business entities. One commenter stated that the SERs' input is very important because more than 90 percent of public power utility systems meet the definition and qualify as small businesses under the SBREFA.

Response: The RFA requires that SBAR Panels collect advice and recommendations from SERs on the issues related to:

—The number and description of the small entities to which the proposed rule will apply;
—The projected reporting, recordkeeping and other compliance requirements of the proposed rule;
—Duplication, overlap or conflict between the proposed rule and other federal rules; and
—Alternatives to the proposed rule that accomplish the stated statutory objectives and minimize any significant economic impact on small entities.

The RFA does not require a covered agency to create or assemble information for SERs or for the government panel members. Although CAA section 609(b)(4) requires that the government Panel members review any material the covered agency has prepared in connection with the RFA, the law does not prescribe the materials to be reviewed. The EPA's policy, as reflected in its RFA guidance, is to provide as much information as possible, given time and resource constraints, to enable an informed Panel discussion. In this rulemaking, because of a court-ordered deadline, the EPA was unable to hold a pre-panel meeting but still provided SERs with the information available at the time, held a standard Panel Outreach meeting to collect verbal advice and recommendations from SERs, and provided the standard 14-day written comment period to SERs. The EPA received substantial input from the SERs, and the Panel report describes recommendations made by the Panel on measures the Administrator should consider that would minimize the economic impact of the proposed rule on small entities. The EPA complied with the RFA. In addition, we met with representatives of small businesses, small rural cooperatives, and small governments a number of times during the regulatory development process to discuss their issues and concerns regarding the proposed MATS rule for EGUs.

Comment: One commenter requested that the EPA work with utilities such that new regulations are as flexible and cost efficient as possible.

Response: In developing the final rule, the EPA has considered all information provided prior to, as well as in response to, the proposed rule. The EPA has endeavored to make the final regulations flexible and cost-efficient while adhering to the requirements of the CAA. The final rule includes a number of flexibilities, such as those related to monitoring requirements, that will lower costs and simplify compliance for small businesses and local governments.

Comment: One commenter was concerned about the ability of small entities or nonprofit utilities such as those owned and/or operated by rural electric co-op utilities, and municipal utilities to comply with the proposed standards within 3 years. The commenter believes that the EPA disregarded the SER panelists who explained that under these current economic conditions they have constraints on their ability to raise capital for the construction of control projects and to acquire the necessary resources in order to meet a 3-year compliance deadline. Two commenters expressed concern that smaller utilities and those in rural areas will be unable to get vendors to respond to their requests for proposals, because they will be able to make more money serving larger utilities.

Response: The preamble to the proposed rule (76 FR 25054; May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed (and final) rule. The EPA has provided pursuant to CAA section 112(i)(3)(A) the maximum 3-year period for sources to come into compliance. Sources may also seek a 1-year extension of the compliance period from their Title V permitting authority if the source needs that time to install controls. *See* CAA section 112(i)(3)(B). If the situation described by commenters (*i.e.,* where small entities or nonprofit utilities constraints on ability to raise capital for construction of control projects and to acquire necessary resources) results in the source needing additional time to install controls, they would be in a position to request the 1-year extension.

Comment: Several commenters believe the EPA did not adequately consider the disproportionately large impact on smaller generating units. The commenters note the diseconomies in scale for pollution controls for such units. One commenter noted the rule will create a more serious compliance hurdle for small communities that depend on coal-fired generation to meet their base load demand. The commenter notes that by not subcategorizing units, the EPA is dictating a fuel switch due to the disproportionately high cost on small communities. The other commenter believes the MACT and NSPS standards are unachievable by going too far without really considering the impacts on small municipal units, as public power is critical to communities, jobs, economic viability and electric reliability. A generating and transmissions electric cooperative which qualifies as a small entity believes the rule will ultimately result in increased electricity costs to its members and will negatively impact the economies of the primarily rural areas that they serve. Another commenter believes there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units, particularly given the current market situation and applicable equitable factors. The commenter suggests both the EPA's and SBA's analyses focus exclusively on the effects on entities causing HAP emissions and primarily on those operating obsolete EGUs, and fail to consider either impacts on downwind businesses and governments or the positive impacts on small entities and governments owning and operating competing, clean and modern EGUs.

Response: The EPA disagrees with the commenters' belief that the impacts on smaller generating units were not adequately considered when developing the rule. The EPA determined the number of potentially impacted small entities and assessed the potential impact of the proposed action on small entities, including municipal units. A similar assessment was conducted in support of the final action. Specifically, the EPA estimated the incremental net annualized compliance cost, which is a function of the change in capital and operating costs, fuel costs, and change in revenue. The projected compliance cost was considered relative to the projected revenue from generation. Thus, the EPA's analysis accounts not only for the additional costs these entities face resulting from compliance, but also the impact of higher electricity prices. The EPA evaluated suggestions from SERs, including subcategorization recommendations. In the preamble to the proposed rule, the EPA explains that, normally, any basis for subcategorizing must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not see a distinction between emissions from smaller generating units versus larger units. The EPA acknowledges the comment that there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units.

Comment: One commenter notes that the EPA recognizes LEEs in the rule such that they should receive less onerous monitoring requirements; however, the EPA does not recognize that small and LEEs also need and merit more flexible and achievable pollution control requirements. The commenter notes that the capital costs for emissions control at small utility units is disproportionately high due to inefficiencies in Hg removal, space constraints for control technology retrofits, and the fact that small units have fewer rate base customers across which to spread these costs. The commenter cites the Michigan Department of Environmental Quality report titled ''Michigan's Mercury Electric Utility Workgroup, Final Report on Mercury Emissions from Coal-Fired Power Plants,'' (June 2005). The commenter notes that the EPA has addressed such concerns previously, citing the RIA for the 1997 8-hour ozone standard. The commenter also suggests smaller utility systems generally have less capital to invest in pollution control than larger, investor-owned systems, due to statutory inability to borrow from the private capital markets, statutory debt ceilings, limited bonding capacity, borrowing limitations related to fiscal strain posed by other, non-environmental factors, and other limitations.

Response: The EPA acknowledges that the rule contains reduced monitoring requirements for existing units that qualify as LEEs. Although the EPA does not believe that reduced pollution control requirements are warranted for LEEs, including small entity LEEs, we believe that flexible and achievable pollution control requirements are promoted through alternative standards, alternative compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs.

Comment: One commenter believes that the EPA should develop more limited monitoring requirements for small EGUs. The commenter notes small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as Hg CEMS and PM CEMS. The commenter notes the EPA could have identified monitoring alternatives to the SER panel for consideration.

Response: The EPA provided monitoring alternatives to using PM CEMS, HCl CEMS, and Hg CEMS in its proposed standards and in this final rule. The continuous compliance alternatives are available to all affected sources, including small entities. As alternatives to the use of PM CEMS and HCl CEMS, sources are allowed to conduct additional performance testing. Sorbent trap monitoring is allowed in lieu of Hg CEMS.

Comment: Several commenters believe the EPA has not sufficiently complied with the requirements of the RFA or adequately considered the impact this rulemaking would have on small entities. One commenter believes the EPA has not engaged in meaningful outreach and consultation with small entities and therefore recommends that the EPA seek to revise the court-ordered deadlines to which this rulemaking is subject, re-convene the SBAR panel, prepare a new initial regulatory flexibility analysis (IRFA), and issue it for additional public comment prior to final rulemaking. The commenter believes the IRFA does not sufficiently consider impacts on small entities as identified in the SBAR Panel Report. The commenter believes it is not apparent that the EPA considered the recommendations of the Panel. The commenter believes the description of significant alternatives in the IRFA is almost entirely quoted from the SBAR Panel Report, which the commenter does not believe is an adequate substitute for the EPA's own analysis of alternatives. The commenter also notes the EPA does not discuss the potential impacts of its decisions on small entities or the impacts of possible flexibilities. Where the EPA does consider regulatory alternatives in principle, the commenter believes it does not provide sufficient support for its decisions to understand on what basis the EPA rejected alternatives that may or may not have reduced burden on small entities while meeting the stated objectives of the rule. Additionally, the commenter notes that the EPA did not evaluate the economic or environmental impacts of significant alternatives to the proposed rule. One commenter believes that the EPA's stated reasons for declining to specify or analyze an area source standard are inadequate under the RFA. The commenter believes the EPA must give serious consideration to regulatory alternatives that accomplish the stated objectives of the CAA while minimizing any significant economic impacts on small entities and that the EPA has a duty to specify and analyze this option or to more clearly state its policy reasons for excluding serious consideration of a separate standard for area sources. A commenter believes the EPA did not fully consider the subcategorization of sources such as boilers designed to burn lignite coals versus other fossil fuels, especially in regard to non-mercury metal and acid gas emissions. The commenter references the SBAR Panel Report suggestion provided in the preamble of the proposed rule that the EPA consider developing an area source vs. major source distinction for the source category and the EPA's response. Another commenter is concerned that the recommendations made by the SER participants were ignored and not discussed in the rulemaking. Specifically, the commenter notes the EPA did not discuss subcategorizing by age, type of plant, fuel, physical space constraints or useful anticipated life of the plant. Nor did the EPA establish GACT for smaller emitters to alleviate regulatory costs and operational difficulties. A commenter believes it is likely that different numerical or work practice standards are appropriate for area sources of HAP.

Response: The EPA disagrees with one commenter's assertion that the agency has not complied with the requirements of the RFA. The EPA complied with both the letter and spirit of the RFA, notwithstanding the constraints of the court-ordered deadline. For example, the EPA notified the Chief Counsel for Advocacy of the SBA of its intent to convene a Panel; compiled a list of SERs for the Panel to consult with; and convened the Panel. The Panel met with SERs to collect their advice and recommendations; reviewed the EPA materials; and drafted a report of Panel findings. The EPA further disagrees with the commenter's assertion that the EPA's IRFA does not sufficiently consider impacts on small entities. The EPA's IRFA, which is included in chapter 10 of the RIA for the proposed rule, addresses the statutorily required elements of an IRFA, such as the economic impact of the proposed rule on small entities and the Panel's findings.

The EPA disagrees with the comment that recommendations made by the SERs were not considered or discussed in the proposed rulemaking such as recommendations regarding subcategorization and separate GACT standards for area sources. The preamble to the proposed standards includes a detailed discussion of how the EPA determined which subcategories and sources would be regulated (76 FR 25036–25037; May 3, 2011). In that discussion, the EPA explains the rationale for its proposed subcategories based on five unit design types. In addition, the EPA acknowledges the subcategorization suggestions from the SERs and explains its reasons for not subcategorizing on those bases. The preamble to the proposed standards also includes a discussion of the SERs' suggestion that area source EGUs be distinguished from major-source EGUs and the EPA's reasons for not making that distinction (76 FR 25020–25021; May 3, 2011).

The EPA also disagrees with the suggestion that the Agency pursue an extension of the timeline for final rulemaking such that the SBAR Panel can be reconvened and a new IRFA can be prepared and released for public comment prior to the final rulemaking. The EPA entered into a Consent Decree to resolve litigation alleging that the EPA failed to perform a non-discretionary duty to promulgate CAA section 112(d) standards for EGUs. *See American Nurses Ass'n* v. *EPA,* 08–2198 (D.D.C.). That Decree required the EPA to sign the final MATS rule by November 16, 2011, unless the agency sought to extend the deadline consistent with the requirements of the modification provision of the Consent Decree. The EPA and Plaintiffs stipulated to a 30-day extension consistent with the modification provisions of the Consent Decree and the rule must be signed no later than December 16, 2011. If plaintiffs in the *American Nurses* litigation objected to an additional extension request, which we believe would have been likely, the Agency would have had to file a motion with the Court seeking an extension of the deadline. Consistent with governing case law, the Agency would have been required to demonstrate in its motion for extension that it was impossible to finalize the rule by the deadline provided in the Consent Decree. *See Sierra Club* v. *Jackson,* Civil Action No. 01–1537 (D.D.C.) (Opinion of the Court denying EPA's motion to extend a consent decree deadline). The EPA negotiated a 30-day extension and was able to complete the rule by December 16, 2011; accordingly, the Agency had no basis for seeking a further extension of time.

A detailed description of the changes made to the rule since proposal, including those made as a result of feedback received during the public comment process can be found in sections VI (NESHAP) and X (NSPS) of this preamble. Changes explained in the identified sections include those related to applicability; subcategorization; work practices; periods of startup, shutdown, and malfunction; initial testing and compliance; continuous compliance; and notification, recordkeeping, and reporting.

4. Description and Estimate of the Affected Small Entities

For the purposes of assessing the impacts of MATS on small entities, a small entity is defined as:

(1) A small business according to the Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for electric utilities is 4 billion kilowatt hours (kWh) of production or less;

(2) A small government jurisdiction that is a government of a city, county, town, district, or special district with a population of less than 50,000; and

(3) A small organization that is any not for profit enterprise that is independently owned and operated and is not dominant in its field.

The EPA examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected entities will install control technologies in compliance with MATS. This analysis does not examine potential indirect economic impacts associated with this rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

The EPA used Velocity Suite's Ventyx data as a basis for identifying plant ownership and compiling the list of potentially affected small entities. The Ventyx dataset contains detailed ownership and corporate affiliation information. The analysis focused only on those EGUs affected by the rule, which includes units burning coal, oil, petroleum coke, or coal refuse as the primary fuel, and excludes any combustion turbine units or EGUs burning natural gas. Also, because the rule does not affect combustion units with an equivalent electricity generating capacity up to 25 MW, small entities that do not own at least one combustion unit with a capacity greater than 25 MW were removed from the dataset. For the affected units remaining, boiler and generator capacity, heat input, generation, and emissions data were aggregated by owner and then by parent company. Entities with more than 4 billion kWh of annual electricity generation were removed from the list, as were municipal owned entities with a population greater than 50,000. For cooperatives, investor owned utilities, and subdivisions that generate less than 4 billion kWh of electricity annually but which may be part of a large entity, additional research on power sales, operating revenues, and other business activities was performed to make a final determination regarding size. Finally, small entities for which the IPM does not project generation in 2015 in the base case were omitted from the analysis because they are not projected to be operating and, thus, are not projected to face the costs of compliance with the rule. After omitting entities for the reasons above, the EPA identified a total of 82 potentially affected small entities that are affiliated with 102 EGUs.

5. Compliance Cost Impacts

The number of potentially affected small entities by ownership type and potential impacts of MATS are presented in Chapter 7 of the RIA and summarized here. The EPA estimated the annualized net compliance cost to small entities to be approximately $106 million in 2015 (2007$).

The EPA assessed the economic and financial impacts of the final rule using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent. Of the 82 small entities identified, The EPA's analysis shows 40 entities may experience compliance costs greater than 1 percent of base generation revenues in 2015, and 35 may experience compliance costs greater than 3 percent of base revenues. Also, all generating capacity at 3 small entities is projected to be uneconomic to maintain. In this analysis, the cost of withdrawing a unit as uneconomic is estimated as the base case profit that is forgone by not operating under the policy case. Because 35 of the 82 total units, or more than 40 percent, are estimated to incur compliance cost greater than 3 percent of base revenues, the EPA has concluded that it cannot certify that there will be no significant economic impact on a substantial number of small entities (SISNOSE) for this rule. Results for small entities discussed here do not account for the reality that electricity markets are regulated in parts of the country. Entities operating in regulated or cost-of-service markets should be able to recover all of their costs of compliance through rate adjustments.

Note that the estimated costs for small entities are significantly lower than those estimated by the EPA for the MATS proposal (which were $379 million). This is driven by a small group of units (less than 6 percent) which were projected to be uneconomic to operate under the proposal (and hence incurred lost profits due to lost electricity revenues), but are now projected to continue their operations under MATS. In addition, the EPA's modeling indicates one unit that would have operated at a low capacity factor under the base case would find it economical to increase its generation significantly under MATS to meet electricity demand in its region. Excluding this unit, the total cost impacts across all entities would be roughly $175 million. Changes in compliance behavior for this small group of units, in particular the one unit which operates at a higher capacity factor, has a substantial impact on total costs as their increased generation revenues offsets a large portion of the compliance costs.

The most significant components of incremental costs to these entities are changes in electricity revenues, followed by the increased capital and operating costs for retrofits. Capital and operating costs increase across all ownership types, but the direction of changes in electricity revenues varies among ownership types. All ownership types, with the exception of private entities, experience a net gain in electricity revenues under the MATS, unlike projections from the EPA's modeling during the proposal, where only municipals benefitted from higher electricity revenues. The change in electricity revenue takes into account both the profit lost from units that do not operate under the policy case and the difference in revenue for operating units under the policy case. According to the EPA's modeling, an estimated 274 MW of capacity owned by small entities are considered uneconomic to operate under the policy case, resulting in a net loss of $13 million (in 2007$) in profits. On the other hand, many operating units actually increase their electricity revenue due to higher electricity prices under MATS. In addition, as mentioned above, the EPA's modeling indicates one unit finds it economical to increase its capacity factor significantly under the policy case which results in significantly higher revenues offsetting the costs.

6. Description of Steps To Minimize Impacts on Small Entities

Consistent with the requirements of the RFA and SBREFA, the EPA has taken steps to minimize the significant economic impact on small entities. Because this rule does not affect units with a generating capacity of less than 25 MW, small entities that do not own at least one generating unit with a capacity greater than 25 MW are not subject to the rule. According to the EPA's analysis, among the coal- and oil-fired EGUs (*i.e.,* excluding combined cycle gas turbines and gas combustion turbines) about 26 potentially small entities only own EGUs with a capacity less than or equal to 25 MW, and none of those entities are subject to the final rule based on the statutory definition of potentially regulated units.

For units affected by the proposed rule, the EPA considered a number of comments received, both during the Small Business Advocacy Review (SBAR) Panel and the public comment period. While none of the alternatives adopted is specifically applied to small entities, the EPA believes these modifications will make compliance less onerous for all regulated units, including those owned by small entities.

a. Work practice standards. The EPA proposed numerical emission standards that would apply at all times, including during periods of startup and shutdown. After reviewing comments and other data regarding the nature of these periods of operation, the EPA is finalizing a work practice standard for periods of startup and shutdown. The EPA is also finalizing work practice standards for organic HAP from all subcategories of EGUs. Descriptions of the work practice requirements for startup and shutdown, as well as organic HAP and limited-use liquid oil-fired EGUs, can be found in section VI.D–E. of the preamble.

b. Continuous compliance and notification, record-keeping, and reporting. The final rule greatly simplifies the continuous compliance requirements and provides two basic approaches for most situations: use of continuous monitoring and periodic testing. The frequency of periodic testing has been decreased from monthly in the proposal to quarterly in the final rule. In addition to simplifying compliance, the EPA believes these changes considerably reduce the overall burden associated with recordkeeping and reporting. These changes to the final rule are described in more detail in Section VI.G–H of this preamble.

c. Subcategorization. The Small Entity Representatives on the SBAR Panel were generally supportive of subcategorization and suggested a number of additional subcategories the EPA should consider when developing the final rule. Although it was not consistent with the statute to adopt the proposed subcategories, the EPA maintained the existing subcategories and split the ‘‘liquid oil-fired units’’ subcategory into three subcategories—continental, non-continental units, and limited-use units.

d. MACT floor calculations. As recommended by the EPA SBAR Panel representative, the EPA established the MACT floors using all the available ICR data that was received to the maximum extent possible consistent with the CAA requirements. The Agency believes this approach reasonably ensures that the emission limits selected as the MACT floors adequately represent the level of emissions actually achieved by the average of the units in the top 12 percent, considering operational variability of those units.

e. Alternatives not adopted. The EPA did not adopt several of the suggestions posed either during the SBAR Panel or public comment period. The EPA did not propose a percent reduction standard as an alternative to the concentration-based MACT floor. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's consideration of coal preparation practices that remove Hg and other HAP before firing. Also, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s), and such an approach would be difficult to implement and enforce. Furthermore, the EPA does not believe the percent reduction standard is in line with the Court's interpretation of the CAA section 112 requirements. Even if we believed it was appropriate to establish a percent reduction standard, we do not have the data necessary to establish percent reduction standards for HAP, as explained further in the response to comments document.

The EPA determined not to establish GACT standards for area sources for a number of reasons. The data show that similar HAP emissions and control technologies are found on both major and area sources greater than 25 MW, and some large units are synthetic area sources. In fact, because of the significant number of well-controlled EGUs of all sizes, we believe it would be difficult to make a distinction between MACT and GACT. Moreover, the EPA believes the standards for area source EGUs should reflect MACT, rather than GACT, because there is no essential difference between area source and major source EGUs with respect to emissions of HAP.

The EPA determined not to exercise its discretionary authority to establish health-based emission standards for HCl and other HAP acid gases. Given the limitations of the currently available information (*e.g.,* the HAP mix where EGUs are located, and the cumulative impacts of respiratory irritants from nearby sources), the environmental effects of HCl and the other acid gas HAP, and the significant co-benefits from reductions in criteria pollutants the EPA determined that setting a conventional MACT standard for HCl and the other acid gas HAP was the appropriate course of action.

As required by SBREFA section 212, the EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. Small entities will be able to obtain a copy of the Small Entity Compliance guide at the following Web site: *http://www.epa.gov/airquality/powerplanttoxics/actions.html.*

D. Unfunded Mandates Reform Act of 1995

Title II of the UMRA of 1995, Public Law 104–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under UMRA section 202, we generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ‘‘Federal mandates’’ that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating a rule for which a written statement is needed, UMRA section 205 generally requires us to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of UMRA section 205 do not apply when they are inconsistent with applicable law. Moreover, UMRA section 205 allows us to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before we establish any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, we must develop a small government agency plan under UMRA section 203. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

We have determined that this rule contains a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any 1 year. Accordingly, we have prepared a written statement entitled ‘‘Unfunded Mandates Reform Act Analysis’’ under

UMRA section 202 that is within the RIA and which is summarized below.

1. Statutory Authority

As discussed elsewhere in this preamble, the statutory authority for this rulemaking is CAA section 112. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. CAA section 112(b) lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

CAA section 112(d) directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT-based standards. This NESHAP applies to all coal- and oil-fired EGUs.

In compliance with UMRA section 205(a), we identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives were presented in the RIA for the rulemaking.

The regulatory alternative upon which this rule is based represents the MACT floor for all regulated pollutants for all but one EGU subcategory for all but one regulated pollutant for that subcategory. These MACT floor-based standards represent the least costly and least burdensome alternative. Beyond-the-floor emission limits for Hg are for existing coal-fired EGUs in the subcategory for low rank virgin coal EGUs.

2. Social Costs and Benefits

The RIA prepared for this rule including the Agency's assessment of costs and benefits is in the docket.

It is estimated that HAP would be reduced by thousands of tons in 2015, relative to the base case, including reductions in HCl, HF, metallic HAP (including Hg), and several other organic HAP from EGUs. Studies have determined a relationship between exposure to certain of these HAP and the onset of cancer; however, the Agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, significant reductions in $PM_{2.5}$ and SO_2 will occur, including approximately 53 thousand tons of $PM_{2.5}$ and over 1 million tons of SO_2. These reductions will occur by 2016 and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) is a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks, and work-lost days (*i.e.,* days when employees are unable to work). Although we are unable to monetize the benefits associated with the HAP emissions reductions other than for Hg or all benefits associated with Hg reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2016 associated with the implementation of the final rule range from $37 billion to $90 billion (2007 dollars) when using a 3 percent discount rate or from $33 billion to $81 billion (2007 dollars) when using a 7 percent discount rate). Our estimate of costs is $9.6 billion (2007 dollars). For more detailed information on the benefits and costs estimated for this rulemaking, refer to the RIA in the docket.

3. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of this rule are discussed previously in this preamble.

The EPA assessed the economic and financial impacts of the rule on government-owned entities using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent of base revenues. The EPA projects that 42 government entities will have compliance costs greater than 1 percent of base generation revenue in 2016, and 32 may experience compliance costs greater than 3 percent of base revenues. Overall, 6 units owned by government entities are expected to retire. The most significant components of incremental costs to these entities are the increased capital and operating costs, followed by changes in electricity revenues. For more details on these results and the methodology behind their estimation, see the results included in chapter 7 of the RIA.

4. Effects on the National Economy

The UMRA requires that we estimate the effect of this rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this rule is presented in the RIA in the docket. This analysis provides estimates of the effect of this rule on some of the categories mentioned above.

The results of the economic impact analysis are summarized previously in this preamble. The results show that, relative to baseline, there will be an average 3.1 percent increase in electricity price on average nationwide in 2016, with the range of increases from 1.3 percent to 6.3 percent in regions throughout the U.S., and a less than 1 percent increase in natural gas price nationwide in 2016. The roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[377] Power generation from coal-fired plants will fall by about 2 percent nationwide in 2016. No region of the U.S. is expected to experience a double-digit increase in retail electricity prices in 2015 or in any year later than that, according to the Agency's analysis, as a result of this rule. To put the electricity price effects in context, the roughly 3 percent incremental increase in aggregate end-user electricity prices projected to occur over the next 4 years is about the same as the 3 percent absolute average change in total end-user electricity prices observed on an annual basis.[378] Furthermore, the roughly 3 percent incremental price effect of this rule is small relative to the changes observed in the absolute levels of electricity prices over the last 50 years, which have ranged from as much as 23 percent lower (in 1969) to as much as 23 percent higher (in 1982) than prices observed in 2010.[379] Even with this rule in effect, electricity prices are projected to be lower in 2015 and 2020 than they were in 2010.[380]

5. Consultation With Government

The UMRA requires that we describe the extent of the Agency's prior consultation with affected state, local,

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[377] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 to 2010, Table 8–10.

[378] EIA Annual Energy Outlook 2010 annual total electricity prices from 1960 t0 2010, Table 8–10.

[379] Ibid.

[380] Ibid., EIA AEO 2010, Table–10 for price levels; and Chapterr 3 of the RIA for electricity price differential.

and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, UMRA section 203 requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a regulatory action. Consistent with the intergovernmental consultation provisions of UMRA section 204, the EPA initiated consultations with governmental entities affected by this rule. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting held on October 27, 2010, in Washington, DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations of elected state and local officials have been identified by the EPA as the ''Big 10'' organizations appropriate to contact for purpose of consultation with elected officials. The purposes of the consultation were to provide general background on the rule, answer questions, and solicit input from state/local governments. During the meeting, officials asked clarifying questions regarding CAA section 112 requirements and central decision points presented by the EPA (*e.g.,* use of surrogate pollutants to address HAP, subcategorization of source category, assessment of emissions variability). They also expressed uncertainty with regard to how utility boilers owned/operated by state and local entities would be impacted, as well as with regard to the potential burden associated with implementing the rule on state and local entities (*i.e.,* burden to re-permit affected EGUs or update existing permits). Officials requested, and the EPA provided, addresses associated with the 112 state and local governments estimated to be potentially impacted by the rule. The EPA has not received additional questions or requests from state or local officials.

Consistent with UMRA section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Because the potential existed for a significant impact for substantial number of small entities, the EPA convened a SBAR Panel to obtain advice and recommendation of representatives of the small entities that potentially would be subject to the requirements of the rule. As part of that process, the EPA considered several options, which are discussed previously in this preamble. Those options included establishing emission limits, establishing work practice standards, establishing subcategories, and consideration of monitoring options. The regulatory alternative selected is a combination of the options considered and includes provisions regarding a number of the recommendations resulting from the SBAR Panel process as described below (see the Regulatory Flexibility Act discussion in this section of the preamble for more detail).

E. Executive Order 13132, Federalism

Under EO 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or the EPA consults with state and local officials early in the process of developing the final action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. Accordingly, the EPA provides the following federalism summary impact statement as required by section 6(b) of EO 13132.

Based on estimates in the RIA, provided in the docket, the final rule may have federalism implications because the rule may impose approximately $294 million in annual direct compliance costs on an estimated 96 state or local governments. Specifically, we estimate that there are 80 municipalities, 5 states, and 11 political subdivisions (*i.e.,* a public district with territorial boundaries embracing an area wider than a single municipality and frequently covering more than one county for the purpose of generating, transmitting and distributing electric energy) that may be directly impacted by this final rule. Responses to the EPA's 2010 ICR were used to estimate the nationwide number of potentially impacted state or local governments. As previously explained, this 2010 survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of DOE/EIA's ''Annual Electric Generator Report,'' and ''Power Plant Operations Report.''

The EPA consulted with state and local officials in the process of developing the rule to permit them to have meaningful and timely input into its development. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the rule, answer questions, and solicit input. In the final rule, EPA has provided flexibilities that will lower compliance costs for these entities. The EPA also recognizes that municipalities may need a longer compliance timeframe because of required approval processes.

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

Subject to EO 13175 (65 FR 67249; November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. Executive Order 13175 requires the EPA to develop an accountable process to ensure ''meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.''

The EPA has concluded that this action may have tribal implications. The EPA offered consultation with tribal officials early in the regulation development process to permit them an opportunity to have meaningful and timely input. Consultation letters were sent to 584 tribal leaders and provided information regarding the EPA's development of this rule and offered consultation. At the request of the tribes, three consultation meetings were held: December 7, 2010, with the Upper Sioux Community of Minnesota; December 13, 2010, with Moapa Band of Paiutes, Forest County Potawatomi, Standing Rock Sioux Tribal Council, and Fond du Lac Band of Chippewa; January 5, 2011, with the Forest County Potawatomi, and a representative from the National Tribal Air Association (NTAA). In these meetings, the EPA presented the authority under the CAA used to develop these rules and an overview of the industry and the industrial processes that have the potential for regulation. Tribes expressed concerns about the impact of EGUs in Indian country. Specifically, they were concerned about potential Hg deposition and the impact on the water resources of the tribes, with particular concern about the impact on subsistence lifestyles for fishing communities, the cultural impact of impaired water quality for ceremonial purposes, and the economic impact on tourism. In light of these concerns, the tribes expressed interest in an expedited implementation of the rule. Other concerns expressed by tribes related to how the Agency would consider variability in setting the standards, and the use of tribal-specific fish consumption data from the tribes in our assessments. They were not supportive of using work practice standards as part of the rule, and asked the Agency to consider going beyond the MACT floor to offer more protection for the tribal communities.

In addition to these consultations, the EPA also conducted outreach on this rule through presentations at the National Tribal Forum in Milwaukee, WI; phone calls with the NTAA; and a webinar for tribes on the proposed rule. The EPA specifically requested tribal data that could support the appropriate and necessary analyses and the RIA for this rule. In addition, the EPA held individual consultations with the Navajo Nation on October 12, 2011; as well as the Gila River Indian Community, Ak-Chin Indian Community, and the Hopi Nation on October 14, 2011. These tribes expressed concerns about the impact of the rule on the Navajo Generating Station (NGS), the impact on the cost of the water allotted to the tribes from the Central Arizona Project (CAP), the impact on tribal revenues from the coal mining operations (*i.e.,* assumptions about reduced mining if NGS were to retire one or more units), and the impacts on employment of tribal members at both the NGS and the mine. More specific comments can be found in the docket.

The EPA will continue to work with these and other potentially affected tribes as this final rule is implemented.

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

This final rule is subject to EO 13045 (62 FR 19885; April 23, 1997) because it is an economically significant regulatory action as defined by EO 12866, and EPA believes that the environmental health or safety risk addressed by this action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of the standards on children.

Although this final rule is based on technology performance, the standards are designed to protect against hazards to public health with an adequate margin of safety as described in Section III of this preamble. The protection offered by this rule is particularly important for children, especially the developing fetus. As referenced in Chapter 4 of the RIA, ''Mercury and Other HAP Benefits Analysis,'' children are more vulnerable than adults to many HAP emitted by EGUs due to differential behavior patterns and physiology. These unique susceptibilities were carefully considered in a number of different ways in the analyses associated with this rulemaking, and are summarized in the RIA. We also estimate substantial health improvements for children in the form of 130,000 fewer asthma attacks, 3,100 fewer emergency room visits due to asthma, 6,300 fewer cases of acute bronchitis, and approximately 140,000 fewer cases of upper and lower respiratory illness.

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

Executive Order 13211 (66 FR 28355; May 22, 2001) requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, OMB, for actions identified as ''significant energy actions.'' This action, which is a significant regulatory action under EO 12866, is likely to have a significant adverse effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows.

We estimate a 3.1 percent price increase for electricity nationwide in 2016 and a less than 2 percent percentage fall in coal-fired power production as a result of this rule. The EPA projects that electric power sector-delivered natural gas prices will increase by about 0.6 percent over the 2015 to 2030 timeframe. For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 2, 2A, 2C, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 23, 26, 26A, 29, 30B of 40 CFR part 60 and Method 320 of 40 CFR part 63. Consistent with the NTTAA, the EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the proposed rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the final rule.

The voluntary consensus standard American National Standards Institute (ANSI)/American Society of Mechanical Engineers (ASME) PTC 19–10–1981, ''Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus]'' is cited in the final rule for its manual method for measuring the O_2, CO_2, and CO content of exhaust gas. This part of ANSI/ASME PTC 19–10–1981 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6348–03 (Reapproved 2010), ''Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy'' is acceptable as an alternative to Method 320 and is cited in the final rule, but with several conditions: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; and (2) In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be $70\% \geq R \leq 130\%$. If the %R value does not meet this criterion for a target compound, the test data are not acceptable for that compound and the test must be repeated for that analyte (*i.e.,* the sampling and/or analytical procedure should be adjusted before a retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following equation: *Reported Result = (Measured Concentration in the Stack × 100)/% R.*

The voluntary consensus standard ASTM D6784–02, ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method),'' is an acceptable alternative to use of EPA Method 29 for Hg only or Method 30B for the purpose of conducting relative accuracy tests of Hg continuous monitoring systems under this final rule. Because of the limitations of this method in terms of total sampling volume, it is not appropriate for use in performance testing under this rule. In addition to the voluntary consensus standards the EPA used in the final rule, the search for emissions measurement procedures identified 16 other voluntary consensus standards. The EPA determined that 14 of these 16 standards identified for measuring emissions of the HAP or other pollutants subject to emission standards in the final rule were impractical alternatives to EPA test methods for the purposes of this final rule. Therefore, the EPA did not adopt these standards for this purpose. The reasons for this determination for the 14 methods are discussed below, and the remaining 2 methods are discussed later in this section.

The voluntary consensus standard ASTM D3154–00, ''Standard Method for Average Velocity in a Duct (Pitot Tube Method),'' is impractical as an alternative to EPA Methods 1, 2, 3B, and 4 for the purposes of this rulemaking because the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154–00 does not include the following: (1) proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (*e.g.,* magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard ASTM D3464–96 (Reapproved 2001), ''Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer,'' is impractical as an alternative to EPA Method 2 for the purposes of this rule primarily because applicability specifications are not clearly defined, *e.g.,* range of gas composition, temperature limits. Also, the lack of supporting quality assurance data for the calibration procedures and specifications, and certain variability issues that are not adequately addressed by the standard limit the EPA's ability to make a definitive comparison of the method in these areas.

The voluntary consensus standard ISO 10780:1994, ''Stationary Source Emissions—Measurement of Velocity and Volume Flowrate of Gas Streams in Ducts,'' is impractical as an alternative to EPA Method 2 in this rule. The standard recommends the use of an L-shaped pitot, which historically has not been recommended by the EPA. The EPA specifies the S-type design which has large openings that are less likely to plug up with dust.

The voluntary consensus standard, CAN/CSA Z223.2–M86 (1999), ''Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams,'' is unacceptable as a substitute for EPA Method 3A because it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are non-mandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods require drift checks after each run.

Two very similar voluntary consensus standards, ASTM D5835–95 (Reapproved 2001), ''Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration,'' and ISO 10396:1993, ''Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations,'' are impractical alternatives to EPA Method 3A for the purposes of this final rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) Sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, ''Stationary Source Emissions—Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen—Automated Methods,'' is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error, calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

The voluntary consensus standard ASTM D6522–00, ''Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers'' is not an acceptable alternative to EPA Method 3A for measuring CO and O_2 concentrations for this final rule as the method is designed for application to sources firing natural gas.

The voluntary consensus standard ASME PTC–38–80 R85 (1985), ''Determination of the Concentration of Particulate Matter in Gas Streams,'' is not acceptable as an alternative for EPA Method 5 because ASTM PTC–38–80 is not specific about equipment requirements, and instead presents the options available and the pros and cons of each option. The key specific differences between ASME PTC–38–80 and the EPA methods are that the ASME standard: (1) Allows in-stack filter placement as compared to the out-of-stack filter placement in EPA Methods 5 and 17; (2) allows many different types of nozzles, pitots, and filtering equipment; (3) does not specify a filter weighing protocol or a minimum allowable filter weight fluctuation as in the EPA methods; and (4) allows filter paper to be only 99 percent efficient, as compared to the 99.95 percent efficiency required by the EPA methods.

The voluntary consensus standard ASTM D3685/D3685M–98, ''Test Methods for Sampling and Determination of Particulate Matter in Stack Gases,'' is similar to EPA Methods 5 and 17, but is lacking in the following areas that are needed to produce quality, representative particulate data: (1) Requirement that the filter holder temperature should be between 120°C and 134°C, and not just ''above the acid dew-point''; (2) detailed specifications for measuring and monitoring the filter holder temperature during sampling; (3) procedures similar to EPA Methods 1, 2, 3, and 4, that are required by EPA Method 5; (4) technical guidance for performing the Method 5 sampling procedures, *e.g.,* maintaining and monitoring sampling train operating temperatures, specific leak check guidelines and procedures, and use of reagent blanks for determining and subtracting background contamination; and (5) detailed equipment and/or operational requirements, *e.g.,* component exchange leak checks, use of glass cyclones for heavy particulate loading and/or water droplets, operating under a negative stack pressure, exchanging particulate loaded filters, sampling preparation and implementation guidance, sample recovery guidance, data reduction guidance, and particulate sample calculations input.

The voluntary consensus standard ISO 9096:1992, ''Determination of Concentration and Mass Flow Rate of Particulate Matter in Gas Carrying Ducts—Manual Gravimetric Method,'' is not acceptable as an alternative for EPA Method 5. Although sections of ISO 9096 incorporate EPA Methods 1, 2, and 5 to some degree, this ISO standard is not equivalent to EPA Method 5 for collection of PM. The standard ISO 9096 does not provide applicable technical guidance for performing many of the integral procedures specified in Methods 1, 2, and 5. Major performance and operational details are lacking or nonexistent, and detailed quality assurance/quality control guidance for the sampling operations required to produce quality, representative particulate data (*e.g.,* guidance for maintaining and monitoring train operating temperatures, specific leak check guidelines and procedures, and sample preparation and recovery procedures) are not provided by the standard, as in EPA Method 5. Also, details of equipment and/or operational requirements, such as those specified in EPA Method 5, are not included in the ISO standard, *e.g.,* stack gas moisture measurements, data reduction guidance, and particulate sample calculations.

The voluntary consensus standard CAN/CSA Z223.1–M1977, ''Method for the Determination of Particulate Mass Flows in Enclosed Gas Streams,'' is not acceptable as an alternative for EPA Method 5. Detailed technical procedures and quality control measures that are required in EPA Methods 1, 2, 3, and 4 are not included in CAN/CSA Z223.1. Second, CAN/CSA Z223.1 does not include the EPA Method 5 filter weighing requirement to repeat weighing every 6 hours until a constant weight is achieved. Third, EPA Method 5 requires the filter weight to be reported to the nearest 0.1 milligram (mg), while CAN/CSA Z223.1 requires reporting only to the nearest 0.5 mg. Also, CAN/CSA Z223.1 allows the use of a standard pitot for velocity measurement when plugging of the tube opening is not expected to be a problem. The EPA Method 5 requires an S-shaped pitot.

The voluntary consensus standard EN 1911–1,2,3 (1998), ''Stationary Source Emissions-Manual Method of Determination of HCl-Part 1: Sampling of Gases Ratified European Text-Part 2: Gaseous Compounds Absorption Ratified European Text-Part 3: Adsorption Solutions Analysis and Calculation Ratified European Text,'' is impractical as an alternative to EPA Methods 26 and 26A. Part 3 of this standard cannot be considered equivalent to EPA Method 26 or 26A because the sample absorbing solution (water) would be expected to capture both HCl and chlorine gas, if present, without the ability to distinguish between the two. The EPA Methods 26 and 26A use an acidified absorbing solution to first separate HCl and chlorine gas so that they can be selectively absorbed, analyzed, and reported separately. In addition, in EN 1911 the absorption efficiency for chlorine gas would be expected to vary as the pH of the water changed during sampling.

The voluntary consensus standard EN 13211 (1998), is not acceptable as an alternative to the Hg portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the method describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

Two of the 16 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, ''Flow Measurement by Velocity Traverse,'' for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, ''Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters,'' for EPA Method 2.

Finally, in addition to the three voluntary consensus standards identified as acceptable alternatives to EPA methods required in the final rule, the EPA is also specifying four voluntary consensus standards in the rule for use in sampling and analysis of liquid oil samples for moisture content. These standards are: ASTM D95–05 (Reapproved 2010), ''Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation,'' ASTM D4006–11, ''Standard Test Method for Water in Crude Oil by Distillation,'' ASTM D4177–95 (Reapproved 2010), ''Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,'' and ASTM D4057–06 (Reapproved 2011), ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products.''

Table 5, section 4.1.1.5 of appendix A, and section 3.1.2 of appendix B to subpart UUUUU, 40 CFR part 63, list the EPA testing methods included in the final rule. Under section 63.7(f) and section 63.8(f) of subpart A of the General Provisions, a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures specified.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low income, and indigenous populations.

This final rule establishes national emission standards for new and existing EGUs that combust coal and oil. The EPA estimates that there are approximately 1,400 units located at 600 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from EGUs. This includes metals (Hg, As, Be, Cd, Cr, Pb, Mn, Ni, and Se), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), and acid gases (HCl and HF). At sufficient levels of exposure, these pollutants can cause a range of health effects including cancer; irritation of the lungs, skin, and mucous membranes; effects on the central nervous system such as memory and IQ loss and learning disabilities; damage to the kidneys; and other acute health disorders.

The final rule will also result in substantial reductions of criteria pollutants such as CO, PM, and SO_2. Sulfur dioxide is a precursor pollutant that is often transformed into fine PM ($PM_{2.5}$) in the atmosphere. Reducing direct emissions of $PM_{2.5}$ and SO_2 will, as a result, reduce concentrations of $PM_{2.5}$ in the atmosphere. These reductions in $PM_{2.5}$ will provide large health benefits, such as reducing the risk of premature mortality for adults, chronic and acute bronchitis, childhood asthma attacks, and hospitalizations for other respiratory and cardiovascular diseases. (For more details on the health effects of metals, organics, and $PM_{2.5}$, please refer to the RIA contained in the docket for this rulemaking.) This final rule will also have a small effect on electricity and natural gas prices but has the potential to affect the cost structure of the utility industry and could lead to shifts in how and where electricity is generated.

This final rule is one of a group of regulatory actions that the EPA has taken and will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to HAP and $PM_{2.5}$, as well as to other pollutants, from EGUs and other sources. In addition, the EPA will pursue energy efficiency improvements throughout the economy, along with other federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in many, if not most, of these actions from EJ communities, among many others.

1. Key EJ Aspects of the Rule

This is an air toxics rule; therefore, it does not permit emissions trading among sources. Instead, this final rule will place a limit on the rates of Hg and other HAP emitted from each affected EGU. As a result, emissions of Hg and other HAP such as HCl will be substantially reduced in the vast majority of states. In some states, however, there may be small increases in Hg and other HAP emissions due to shifts in electricity generation from EGUs with higher emission rates to EGUs with already low emission rates. Hydrogen chloride emissions are projected to increase at a small number of sources but that does not lead to any increased emissions at the state level.

The primary risk analysis to support the finding that this final rule is both appropriate and necessary includes an analysis of the effects of Hg from EGUs on people who rely on freshwater fish they catch as a regular and frequent part of their diet. These groups are characterized as subsistence level fishing populations or fishers. A significant portion of the data in this analysis came from published studies of EJ communities where people frequently consume locally-caught freshwater fish. These communities included: (1) White and black populations (including female and poor strata) surveyed in South Carolina; (2) Hispanic, Vietnamese and Laotian populations surveyed in California; and (3) Great Lakes tribal populations (Chippewa and Ojibwe) active on ceded territories around the Great Lakes. These data were used to help estimate risks to similar populations beyond the areas where the study data were collected. For example, while the Vietnamese and Laotian survey data were collected in California, given the ethnic (heritage) nature of these high fish consumption rates, we assumed that they could also be associated with members of these ethnic groups living elsewhere in the U.S. Therefore, the high-end consumption rates referenced in the California study for these ethnic groups were used to model risk at watersheds elsewhere in the U.S. As a result of this approach, the specific fish consumption patterns of several different EJ groups are fundamental to the EPA's assessment of both the underlying risks that make this final rule appropriate and necessary, and of the analysis of the benefits of reducing exposure to Hg and the other HAP.

The EPA's full analysis of risks from consumption of Hg-contaminated fish is contained in the RIA for this rule. The effects of this final rule on the health risks from Hg and other HAP are presented in the preamble and in the RIA for this rule.

2. Potential Environmental and Public Health Impacts to Minority, Low Income, or Tribal Populations

The EPA has conducted several analyses that provide additional insight on the potential effects of this rule on EJ communities. These include: (1) The socio-economic distribution of people living close to affected EGUs who may be exposed to pollution from these sources; and (2) an analysis of the distribution of health effects expected from the reductions in $PM_{2.5}$ that will result from implementation of this final rule (co-benefits).

a. Socio-Economic Distribution. As part of the analysis for this final rule, the EPA reviewed the aggregate demographic makeup of the communities near EGUs covered by this final rule. Although this analysis gives some indication of populations that may be exposed to levels of pollution that cause concern, it does not identify the demographic characteristics of the most highly affected individuals or communities. Electric generating units usually have very tall emission stacks; this tends to disperse the pollutants emitted from these stacks fairly far from the source. In addition, several of the pollutants emitted by these sources, such as a common form of Hg and SO_2, are known to travel long distances and contribute to adverse impacts on both the environment and human health hundreds or even thousands of miles from where they were emitted (in the case of elemental Hg, globally).

The proximity-to-the-source review is included in the analysis for this final rule because some EGUs emit enough HAP such as Ni or Cr(VI) to cause elevated lifetime cancer risks greater than 1 in a million in nearby communities. In addition, the EPA's analysis indicates that there are localized areas with potential for elevated levels of Hg deposition around most U.S. EGUs.[381]

The analysis of demographic data used proximity-to-the-source as a surrogate for exposure to identify those populations considered to be living near affected sources, such that they have notable exposures to current HAP

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[381] See Excess Local Deposition TSD for more detail.

emissions from these sources. The demographic data for this analysis were extracted from the 2000 census data which were provided to the EPA by the U.S. Census Bureau. Distributions by race are based on demographic information at the census block level, and all other demographic groups are based on the extrapolation of census block group level data to the census block level. The socio-demographic parameters used in the analysis included the following categories: Racial (White, African American, Native American, Other or Multiracial, and All Other Races); Ethnicity (Hispanic); and Other (Number of people below the poverty line, Number of people with ages between 0 and 18, Number of people greater than or equal to 65, Number of people with no high school diploma).

In determining the aggregate demographic makeup of the communities near affected sources, the EPA focused on those census blocks within three miles of affected sources and determined the demographic composition (*e.g.,* race, income, etc.) of these census blocks and compared them to the corresponding compositions nationally. The radius of 3 miles (or approximately 5 kilometers) is consistent with other demographic analyses focused on areas around potential sources. In addition, air quality modeling experience has shown that the area within three miles of an individual source of emissions can generally be considered the area with the highest ambient air levels of the primary pollutants being emitted for most sources, both in absolute terms and relative to the contribution of other sources (assuming there are other sources in the area, as is typical in urban areas). Although facility processes and fugitive emissions may have more localized impacts, the EPA acknowledges that because of various stack heights there is the potential for dispersion beyond 3 miles. To the extent that any minority, low income, and indigenous subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also stands to see increased environmental and health benefit from the emissions reductions called for by this rule. The results of the EPA's demographic analysis for affected sources are shown in the following table:[382] [383]

TABLE 12—COMPARATIVE SUMMARY OF THE DEMOGRAPHICS WITHIN 5 KM (3 MILES) OF THE AFFECTED SOURCES

[Population in millions][382]

	White	African American	Native American	Other and multiracial	Hispanic	Minority[383]	Below poverty line
Near Source Total (3 mi)	8.78	2.51	0.10	2.52	2.86	5.13	2.43
% of Near Source Total	63	18	1	18	21	37	17
National Total	215	35	2.49	33.3	39.1	70.8	37.1
% of National Total	75	12	1	12	14	25	13

[382] Racial and ethnic categories overlap and cannot be summed.

[383] The "Minority" population is the overall population (in the first row) minus white population (in the second row).

The data indicate that coal-fired EGUs are located in areas where the minority share of the population living within a three mile buffer is higher than the national average by 12 percentage points or 48 percent. For these same areas, the percent of the population below the poverty line is also higher than the national average by 4 percentage points or 31 percent. These results are presented in more detail in the ''Review of Proximity Analysis,'' February 2011, a copy of which is available in the docket.

b. $PM_{2.5}$ (Co-Benefits) Analysis. As mentioned above, many of the steps EGUs will take to reduce their emissions of air toxics as required by this final rule will also reduce emissions of PM and SO_2. As a result, this final rule will reduce concentrations of $PM_{2.5}$ in the atmosphere. Exposure to $PM_{2.5}$ can cause or contribute to adverse health effects, such as asthma and heart disease, that significantly affect many minority, low-income, and tribal individuals and their communities. Fine PM ($PM_{2.5}$) is particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure can cause premature death and trigger heart attacks, asthma attacks in children and adults with asthma, chronic and acute bronchitis, and emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. Missing work due to illness or the illness of a child is a particular problem for people who have jobs that do not provide paid sick days. Low-wage employees also risk losing their jobs if they are absent too often, even if it is due to their own illness or the illness of a child or other relative. Finally, many individuals in these communities lack access to high quality health care to treat these types of illnesses. Due to all these factors, many minority and low-income communities are particularly susceptible to the health effects of $PM_{2.5}$ and receive a variety of benefits from reducing it.

We estimate that in 2016 the annual PM-related benefits of the final rule for adults include approximately 4,200 to 11,000 fewer premature mortalities, 2,900 fewer cases of chronic bronchitis, 4,800 fewer non-fatal heart attacks, 2,600 fewer hospitalizations (for respiratory and cardiovascular disease combined), 3.2 million fewer days of restricted activity due to respiratory illness and approximately 540,000 fewer lost work days. As described in EO 13045, Protection of Children from Environmental Health Risks and Safety Risks, we also estimate substantial health improvements for children.

We also examined the $PM_{2.5}$ mortality risks according to race, income, and educational attainment. We then estimated the change in $PM_{2.5}$ mortality risk as a result of this final rule among people living in the counties with the highest (top 5 percent) $PM_{2.5}$ mortality risk in 2005. We then compared the change in risk among the people living in these ''high-risk'' counties with people living in all other counties.

In 2005, people living in the highest risk counties and in the poorest counties had a substantially higher risk of $PM_{2.5}$-related death than people living in the other 95 percent of counties. This was true regardless of race; the difference between the groups of counties for each race was large while the differences among races in both groups of counties was very small. In contrast, the analysis found that people with less than high school education had a significantly greater risk from $PM_{2.5}$ mortality than people with a greater than high school education. This was true both for the highest-risk counties and for the other counties. In summary, the analysis indicates that in 2005, educational status, living in one of the poorest counties, and living in a high-risk county are associated with higher $PM_{2.5}$ mortality risk while race is not.

Our analysis demonstrates that this final rule will significantly reduce the $PM_{2.5}$ mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2016 pre-rule (*i.e.,* base case) levels. The analysis indicates that people living in counties with the highest rates (top 5 percent) of $PM_{2.5}$ mortality risk in 2005 receive the largest reduction in mortality risk after this rule takes effect. We also find that people living in the poorest 5 percent of the counties receive a larger reduction in $PM_{2.5}$ mortality risk than all other counties. More information can be found in Section 7.11 of the RIA.

The EPA estimates that the benefits of the final rule are distributed among races, income levels, and levels of education fairly evenly. However, the analysis does indicate that this final rule in conjunction with the implementation of existing or final rules (*e.g.,* the CSAPR) will reduce the disparity in risk between those in the highest-risk counties and the other 95 percent of counties for all races and educational levels. In addition, in many cases implementation of this final rule and other rules will, together, reduce risks in the highest-risk counties to the approximate level of risk for the rest of the counties as it existed before implementation of the rule.

These results are presented in more detail in Section 7.11 of the RIA.

3. Meaningful Public Participation

The EPA defines ''environmental justice'' to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. To promote meaningful involvement, the EPA publicized the rulemaking via newsletters, EJ listserves, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). During the comment period, the EPA discussed the proposed rule via a conference call with communities, conducted a community-oriented webinar on the proposed rule, and posted the webinar presentation online. The EPA also held three public hearings to receive additional input on the proposal.

There will continue to be opportunities for public notice and comment as the utilities move forward with implementation of this rule. Once the rule is finalized, affected EGUs will need to update their Title V operating permits to reflect their new emission limits, any other new applicable requirements, and the associated monitoring and recordkeeping from this rule. The Title V permitting process provides that when most permits are reopened (for example, to incorporate new applicable requirements) or renewed, there must be opportunity for public review and comments. In addition, after the public review process, the EPA has an opportunity to review the proposed permit and object to its issuance if it does not meet CAA requirements.

4. Additional Analysis

In addition to the previously described assessment of EJ impacts, the EPA conducted an analysis of sub-populations with particularly high potential risks of Hg exposure due to high rates of fish consumption. These populations overlap in many cases with traditional EJ populations and would benefit from Hg reductions resulting from this rule. The EPA also conducted an analysis of the distribution of $PM_{2.5}$-related mortality risk according to the race, income and education of the population and how MATS changes this distribution. These analyses can be found in Section 7.12 of the RIA.

5. Summary

This final rule strictly limits the emissions rate of Hg and other HAP from every affected EGU. The EPA's analysis indicates substantial health benefits, including for minority, low income, and indigenous populations, from reductions in $PM_{2.5}$.

The EPA's analysis also indicates reductions in risks for individuals, including for members of minority populations, who eat fish frequently from U.S. lakes and rivers and who live near affected sources. Based on all the available information, the EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, and indigenous populations. The EPA is providing multiple opportunities for EJ communities to both learn about and comment on this rule and welcomes their participation as implementation of the rule proceeds.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the U.S. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective April 16, 2012.

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

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

Dated: December 16, 2011.

Lisa P. Jackson,
Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of the Federal Regulations is amended as follows:

PART 60—[AMENDED]

■ 1. The authority citation for part 60 continues to read as follows:

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

Subpart A—[Amended]

■ 2. Section 60.17 is amended:

■ a. By redesignating paragraph (a)(93), added March 21, 2011, at 76 FR 15750, and delayed indefinitely at 76 FR 28664, May 18, 2011, as paragraph (a)(96);

■ b. By redesignating paragraphs (a)(91) and (a)(92) as paragraphs (a)(94) and (a)(95);
■ c. By redesignating paragraphs (a)(89) and (a)(90) as paragraphs (a)(91) and (a)(92);
■ d. By redesignating paragraphs (a)(54) through (a)(88) as paragraphs (a)(55) through (a)(89);
■ e. By adding paragraph (a)(54);
■ f. By adding paragraph (a)(90); and
■ g. By adding paragraph (a)(93) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(54) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, approved September 1, 2008, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(90) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, approved July 15, 2011, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

(93) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, approved August 1, 2010, IBR approved for §§ 60.41b of subpart Db of this part and 60.41c of subpart Dc of this part.

* * * * *

Subpart B—[Amended]

■ 3. Section 60.21 is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (f).
■ c. By removing paragraph (k).

§ 60.21 Definitions.

* * * * *

(a) *Designated pollutant* means any air pollutant, the emissions of which are subject to a standard of performance for new stationary sources, but for which air quality criteria have not been issued and that is not included on a list published under section 108(a) or section 112(b)(1)(A) of the Act.

* * * * *

(f) *Emission standard* means a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions.

* * * * *

■ 4. Section 60.24 is amended as follows:
■ a. By revising paragraph (b)(1).
■ b. By removing paragraph (h).

§ 60.24 Emission standards and compliance schedules.

* * * * *

(b) * * *

(1) Emission standards shall either be based on an allowance system or prescribe allowable rates of emissions except when it is clearly impracticable. Such cases will be identified in the guideline documents issued under § 60.22. Where emission standards prescribing equipment specifications are established, the plan shall, to the degree possible, set forth the emission reductions achievable by implementation of such specifications, and may permit compliance by the use of equipment determined by the State to be equivalent to that prescribed.

* * * * *

Subpart D—[Amended]

■ 5. The subpart heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators

■ 6. Section 60.40 is amended by revising paragraph (e) to read as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(e) Any facility subject to either subpart Da or KKKK of this part is not subject to this subpart.

■ 7. Section 60.41 is amended by adding the definition of ''natural gas'' in alphabetical order to read as follows:

§ 60.41 Definitions.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

* * * * *

■ 8. Section 60.42 is amended as follows:
■ a. By revising paragraph (a) introductory text.
■ b. By adding paragraph (d).
■ c. By adding paragraph (e).

§ 60.42 Standard for particulate matter (PM).

(a) Except as provided under paragraphs (b), (c), (d), and (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

* * * * *

(d) An owner or operator of an affected facility that combusts only natural gas is exempt from the PM and opacity standards specified in paragraph (a) of this section.

(e) An owner or operator of an affected facility that combusts only gaseous or liquid fossil fuel (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM is exempt from the PM standards specified in paragraph (a) of this section.

■ 9. Section 60.45 is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (b) introductory text.
■ c. By revising paragraphs (b)(1) through (5).
■ d. By revising paragraph (b)(6) introductory text.
■ e. By revising paragraphs (b)(7)(i)(A) through (C).
■ f. By revising paragraph (b)(7)(ii)(B).
■ g. By adding paragraph (b)(8).

§ 60.45 Emissions and fuel monitoring.

(a) Each owner or operator of an affected facility subject to the applicable emissions standard shall install, calibrate, maintain, and operate continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring SO_2 emissions, NO_X emissions, and either oxygen (O_2) or carbon dioxide (CO_2) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS and COMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that combusts only gaseous or liquid fossil fuel (excluding residual oil)

with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and that does not use post-combustion technology to reduce emissions of SO_2 or PM, COMS for measuring the opacity of emissions and CEMS for measuring SO_2 emissions are not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis or fuel receipts.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring SO_2 emissions is not required if the owner or operator monitors SO_2 emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NO_X may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO_X are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NO_X emissions is not required. If the initial performance test results show that NO_X emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO_X within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator is not required to and elects not to install any CEMS for either SO_2 or NO_X, a CEMS for measuring either O_2 or CO_2 is not required.

(5) For affected facilities using a PM CEMS, a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in § 60.48Da of this part, or an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part a COMS is not required.

(6) A COMS for measuring the opacity of emissions is not required for an affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

* * * * *

(7) * * *

(i) * * *

(A) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(C) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(ii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(8) A COMS for measuring the opacity of emissions is not required for an affected facility at which the owner or operator installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

* * * * *

Subpart Da—[Amended]

■ 10. The subpart heading for Subpart Da is revised to read as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

■ 11. Section 60.40Da is amended by revising paragraphs (b)(1) and (e) to read as follows:

§ 60.40Da Applicability and designation of affected facility.

* * * * *

(b) * * *

(1) The IGCC electric utility steam generating unit is capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) in the combustion turbine engine and associated heat recovery steam generator; and

* * * * *

(e) Applicability of this subpart to an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit is as specified in paragraphs (e)(1) through (3) of this section.

(1) Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part.

(2) For heat recovery steam generators use with duct burners subject to this subpart, only emissions resulting from the combustion of fuels in the steam generating unit (*i.e.* duct burners) are subject to the standards under this subpart. (The emissions resulting from the combustion of fuels in the stationary combustion turbine engine are subject to subpart GG or KKKK, as applicable, of this part.)

(3) Any affected facility that meets the applicability requirements and is subject to subpart Eb or subpart CCCC of this part is not subject to the emission standards under subpart Da.

■ 12. Section 60.41Da is amended as follows:

■ a. By revising the definitions of ''boiler operating day'', ''gaseous fuel'', ''integrated gasification combined cycle electric utility steam generating unit'', ''natural gas'', ''petroleum'', ''potential combustion concentration'', and ''steam generating unit''.

■ b. By adding the definitions of ''affirmative defense'', ''combined heat and power'', ''gross energy output'', ''net energy output'', ''out-of-control period'', and ''petroleum coke'' in alphabetical order.

■ c. By removing the definitions of ''available purchase power'', ''cogeneration'', ''dry flue gas desulfurization technology '', ''electric utility company'', ''emergency condition'', ''emission rate period'', ''gross output'', ''interconnected'', ''net system capacity'', ''principal company'', ''responsible official'', ''spare flue gas desulfurization system module'', ''spinning reserve'', ''system emergency reserves'', and ''system load''.

§ 60.41Da Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Boiler operating day for units constructed, reconstructed, or modified before February 29, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

* * * * *

Combined heat and power, also known as ''cogeneration,'' means a steam-generating unit that simultaneously produces both electric (and mechanical) and useful thermal energy from the same primary energy source.

* * * * *

Gaseous fuel means any fuel that is present as a gas at standard conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

* * * * *

Gross energy output means:

(1) For facilities constructed, reconstructed, or modified before May 4, 2011, the gross electrical or mechanical output from the affected facility plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(2) For facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(3) For combined heat and power facilities constructed, reconstructed, or modified after May 3, 2011, the gross electrical or mechanical output from the affected facility divided by 0.95 minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process);

(4) For a IGCC electric utility generating unit that coproduces chemicals constructed, reconstructed, or modified after May 3, 2011, the gross useful work performed is the gross electrical or mechanical output from the unit minus electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) that are associated with power production plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process). Auxiliary loads that are associated with power production are determined based on the energy in the coproduced chemicals compared to the energy of the syngas combusted in combustion turbine engine and associated duct burners.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction or repair. No solid fuel is directly burned in the unit during operation.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net energy output means the gross energy output minus the parasitic load associated with power production. Parasitic load includes, but is not limited to, the power required to operate the equipment used for fuel delivery systems, air pollution control systems, wastewater treatment systems, ash handling and disposal systems, and other controls (*i.e.,* pumps, fans, compressors, motors, instrumentation, and other ancillary equipment required to operate the affected facility).

* * * * *

Out-of-control period means any period beginning with the quadrant corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications and ending with the quadrant corresponding to the completion of an additional calibration error, linearity check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Petroleum for facilities constructed, reconstructed, or modified before May 4, 2011, means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, and residual oil. For units constructed, reconstructed, or modified after May 3, 2011, *petroleum* means crude oil or a fuel derived from crude oil, including, but not limited to, distillate oil, residual oil, and petroleum coke.

Petroleum coke, also known as ''petcoke,'' means a carbonization product of high-boiling hydrocarbon fractions obtained in petroleum processing (heavy residues). *Petroleum* *coke* is typically derived from oil refinery coker units or other cracking processes.

Potential combustion concentration means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems. For sulfur dioxide (SO_2) the potential combustion concentration is determined under § 60.50Da(c).

* * * * *

Steam generating unit for facilities constructed, reconstructed, or modified before May 4, 2011, means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included). For units constructed, reconstructed, or modified after May 3, 2011, *steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated combustion turbines and fuel cells.

* * * * *

■ 13. Section 60.42Da is revised to read as follows:

§ 60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input.

(b) Except as provided in paragraphs (b)(1) and (b)(2) of this section, on and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(1) An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart is exempt from the opacity standard specified in this paragraph (b) of this section.

(2) An owner or operator of an affected facility that combusts only natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

(c) Except as provided in paragraphs (d) and (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of:

(1) 13 ng/J (0.030 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) For an affected facility that commenced construction or reconstruction, 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) when combusting solid, liquid, or gaseous fuel, or

(3) For an affected facility that commenced modification, 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) when combusting solid, liquid, or gaseous fuel.

(e) Except as provided in paragraph (f) of this section, the owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall meet the requirements specified in paragraphs (e)(1) and (2) of this section.

(1) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator shall cause to be discharged into the atmosphere from that affected facility at all times except during periods of startup and shutdown, any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction, any gases that contain PM in excess of either:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

(ii) For an affected facility which commenced modification, any gases that contain PM in excess of 13 ng/J (0.015 lb/MMBtu) heat input.

(2) During periods of startup and shutdown, the owner or operator shall meet the work practice standards specified in Table 3 to subpart UUUUU of part 63.

(f) An owner or operator of an affected facility that meets the conditions in either paragraphs (f)(1) or (2) of this section is exempt from the PM emissions limits in this section.

(1) The affected facility combusts only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and that does not use a post-combustion technology to reduce emissions of SO_2 or PM.

(2) The affected facility is operated under a PM commercial demonstration permit issued by the Administrator according to the provisions of § 60.47Da.

■ 14. Section 60.43Da is amended as follows:

■ a. The section heading is revised.

■ b. By revising paragraphs (a)(1) and (2).

■ c. By adding paragraphs (a)(3) and (4).

■ d. By removing and reserving paragraph (c).

■ e. By revising paragraph (f).

■ f. By revising paragraph (i).

■ g. By revising paragraph (k).

■ h. By adding paragraph (l).

■ i. By adding paragraph (m).

§ 60.43Da Standards for sulfur dioxide (SO_2).

(a) * * *

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction);

(2) 30 percent of the potential combustion concentration (70 percent

reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input;

(3) 180 ng/J (1.4 lb/MWh) gross energy output; or

(4) 65 ng/J (0.15 lb/MMBtu) heat input.

* * * * *

(f) The SO_2 standards under this section do not apply to an owner or operator of an affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

* * * * *

(i) Except as provided in paragraphs (j) and (k) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility which commenced construction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction).

(2) For an affected facility which commenced reconstruction, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction).

(3) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction).

* * * * *

(k) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after February 28, 2005, but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

(l) Except as provided in paragraphs (j) and (m) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility, any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (l)(1) and (2) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain SO_2 in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 140 ng/J (1.2 lb/MWh) net energy output; or

(iii) 3 percent of the potential combustion concentration (97 percent reduction).

(2) For an affected facility which commenced modification, any gases that contain SO_2 in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 10 percent of the potential combustion concentration (90 percent reduction).

(m) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility located in a noncontinental area for which construction, reconstruction, or modification commenced after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the applicable emissions limit specified in paragraphs (m)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 230 ng/J (0.54 lb/MMBtu) heat input.

■ 15. Section 60.44Da is revised to read as follows:

§ 60.44Da Standards for nitrogen oxides (NO_X).

(a) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before July 10, 1997 any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit in paragraphs (a)(1) and (2) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emissions limit listed in the following table as applicable to the fuel type combusted and as determined on a 30-boiler operating day rolling average basis.

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Gaseous fuels:		
Coal-derived fuels	210	0.50
All other fuels	86	0.20
Liquid fuels:		

Fuel type	Emission limit for heat input	
	ng/J	lb/MMBtu
Coal-derived fuels	210	0.50
Shale oil	210	0.50
All other fuels	130	0.30
Solid fuels:		
Coal-derived fuels	210	0.50
Any fuel containing more than 25%, by weight, coal refuse	(1)	(1)
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace [2]	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit [2]	260	0.60
Subbituminous coal	210	0.50
Bituminous coal	260	0.60
Anthracite coal	260	0.60
All other fuels	260	0.60

[1] Exempt from NO_X standards and NO_X monitoring requirements.

[2] Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) When two or more fuels are combusted simultaneously in an affected facility, the applicable emissions limit (E_n) is determined by proration using the following formula:

$$En = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

En = Applicable NO_X emissions limit when multiple fuels are combusted simultaneously (ng/J heat input);
w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;
x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;
y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;
z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and
v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(b) [Reserved]

(c) [Reserved]

(d) Except as provided in paragraph (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after July 9, 1997, but before March 1, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (d)(1) and (2) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 200 ng/J (1.6 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of 65 ng/J (0.15 lb/MMBtu) heat input.

(e) Except as provided in paragraphs (f) and (h) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 but before May 4, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (e)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction, any gases that contain NO_X in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) For an affected facility which commenced reconstruction, any gases that contain NO_X in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input.

(f) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005 but before May 4, 2011, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

(3) In cases when during a 30-boiler operating day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the

30-day compliance period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain NO_X (expressed as NO_2) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

(g) Except as provided in paragraphs (h) of this section and § 60.45Da, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X in excess of either:

(i) 88 ng/J (0.70 lb/MWh) gross energy output; or

(ii) 95 ng/J (0.76 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_X in excess of either:

(i) 110 ng/J (0.85 lb/MWh) gross energy output; or

(ii) 120 ng/J (0.92 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X in excess of 140 ng/J (1.1 lb/MWh) gross energy output.

(h) The NO_X emissions limits under this section do not apply to an owner or operator of an affected facility which is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

■ 16. Section 60.45Da is revised to read as follows:

§ 60.45Da Alternative standards for combined nitrogen oxides (NO_X) and carbon monoxide (CO).

(a) The owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011 as alternate to meeting the applicable NO_X emissions limits specified in § 60.44Da may elect to meet the applicable standards for combined NO_X and CO specified in paragraph (b) of this section.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8 no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) plus CO in excess of the applicable emissions limit specified in paragraphs (b)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NO_X plus CO in excess of either:

(i) 140 ng/J (1.1 lb/MWh) gross energy output; or

(ii) 150 ng/J (1.2 lb/MWh) net energy output.

(2) For an affected facility which commenced construction or reconstruction and that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis, any gases that contain NO_X plus CO in excess of either:

(i) 160 ng/J (1.3 lb/MWh) gross energy output; or

(ii) 170 ng/J (1.4 lb/MWh) net energy output.

(3) For an affected facility which commenced modification, any gases that contain NO_X plus CO in excess of 190 ng/J (1.5 lb/MWh) gross energy output.

■ 17. Section 60.47Da is amended as follows:

■ a. By revising paragraph (c).
■ b. By adding paragraph (f).
■ c. By adding paragraph (g).
■ d. By adding paragraph (h).
■ e. By adding paragraph (i).

§ 60.47Da Commercial demonstration permit.

* * * * *

(c) An owner or operator of an affected facility that uses fluidized bed combustion (atmospheric or pressurized) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43Da(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

* * * * *

(f) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the total PM emission reduction requirements under § 60.42Da but must, as a minimum, reduce PM emissions to less than 6.4 ng/J (0.015 lb/MMBtu) heat input.

(g) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions controls system who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 standards or emission reduction requirements under § 60.43Da but must, as a minimum, reduce SO_2 emissions to 5 percent of the potential combustion concentration (95 percent reduction) or to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(h) An owner or operator of an affected facility that uses a pressurized fluidized bed or a multi-pollutant emissions control system or advanced combustion controls who is issued a commercial demonstration permit by the Administrator is not subject to the NO_X standards or emission reduction requirements under § 60.44Da but must, as a minimum, reduce NO_X emissions to less than 130 ng/J (1.0 lb/MWh) or the combined NO_X plus CO emissions to less than 180 ng/J (1.4 lb/MWh) gross energy output on a 30-boiler operating day rolling average basis.

(i) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category listed in the following table.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	SO_2	1,000

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Multi-pollutant Emission Control	NO_X	1,000
Multi-pollutant Emission Control	PM	1,000
Pressurized Fluidized Bed Combustion	SO_2	1,000
Pressurized Fluidized Bed Combustion	NO_X	1,000
Pressurized Fluidized Bed Combustion	PM	1,000
Advanced Combustion Controls	NO_X	1,000

■ 18. Section 60.48Da is amended as follows:

■ a. By revising paragraphs (a) through (g).

■ b. By revising paragraph (i).

■ c. By revising paragraph (k)(1)(i).

■ d. By revising paragraph (k)(2)(i).

■ e. By revising paragraph (k)(2)(iv).

■ f. By removing and reserving paragraph (l).

■ g. By revising paragraph (m).

■ h. By revising paragraph (n).

■ i. By revising paragraphs (p)(5), (7), and (8).

■ j. By adding paragraph (r).

■ k. By adding paragraph (s).

§ 60.48Da Compliance provisions.

(a) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the applicable PM emissions limit and opacity standard under § 60.42Da, SO_2 emissions limit under § 60.43Da, and NO_X emissions limit under § 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO_2 emissions limit under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da apply at all times. The applicable PM emissions limit and opacity standard under § 60.42Da apply at all times except during periods of startup and shutdown.

(b) After the initial performance test required under § 60.8, compliance with the applicable SO_2 emissions limit and percentage reduction requirements under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for both SO_2, NO_X or NO_X plus CO as applicable, and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards.

(c) For the initial performance test required under § 60.8, compliance with the applicable SO_2 emissions limits and percentage reduction requirements under § 60.43Da, the NO_X emissions limits under § 60.44Da, and the NO_X plus CO emissions limits under § 60.45Da is based on the average emission rates for SO_2, NO_X, CO, and percent reduction for SO_2 for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(d) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_X for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by dividing the sum of the SO_2 and NO_X emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

(e) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable SO_2 percentage reduction requirements is determined based on the ''as fired'' total potential emissions and the total outlet SO_2 emissions for the 30 successive boiler operating days.

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with applicable daily average PM emissions limits is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Daily averages are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable daily average PM emissions limits is determined by dividing the sum of the PM emissions for the 30 successive boiler operating days by the sum of the gross useful output or net energy output, as applicable, for the 30 successive boiler operating days.

(g) For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average NO_X plus CO emissions limit is determined by dividing the sum of the NO_X plus CO emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, as applicable, for the 30 successive boiler operating days.

* * * * *

(i) Compliance provisions for sources subject to § 60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), (f), or (g). The owner or operator shall calculate NO_X emissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_X output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, NO_X emissions may be calculated by multiplying the hourly NO_X emission rate in lb/MMBtu (measured by the CEMS required under § 60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(k) * * *

(1) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 2 in this section:

$$\mathbf{E} = \frac{(Csg \times Qsg) - (Cte \times Qte)}{(Osg \times \mathbf{h})} \qquad (\mathbf{Eq.\,2})$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

C_{te} = Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h);

Q_{te} = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/h (dscf/h);

O_{sg} = Average hourly gross energy output from steam generating unit, J/h (MW); and

h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

* * * * *

(2) * * *

(i) The emission rate (E) of NO_X shall be computed using Equation 3 in this section:

$$\mathbf{E} = \frac{(Csg \times Qsg)}{Occ} \qquad (\mathbf{Eq.\,3})$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

C_{sg} = Average hourly concentration of NO_X exiting the steam generating unit, ng/dscm (lb/dscf);

Q_{sg} = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/h (dscf/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in § 60.49Da(l), determine the mass rate (lb/h) of NO_X emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of NO_X shall be computed using Equation 4 in this section:

$$\mathbf{E} = \frac{(\mathbf{ER}sg \times Hcc)}{Occ} \qquad (\mathbf{Eq.\,4})$$

Where:

E = Emission rate of NO_X from the duct burner, ng/J (lb/MWh) gross energy output;

ER_{sg} = Average hourly emission rate of NO_X exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);

H_{cc} = Average hourly heat input rate of entire combined cycle unit, J/h (MMBtu/h); and

O_{cc} = Average hourly gross energy output from entire combined cycle unit, J/h (MW).

* * * * *

(m) Compliance provisions for sources subject to § 60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), (j)(3)(i), (l)(1)(i), (l)(1)(ii), or (l)(2). The owner or operator shall calculate SO_2 emissions as 1.660×10^{-7} lb/scf-ppm times the average hourly SO_2 output concentration in ppm (measured according to the provisions of § 60.49Da(b)), times the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable. Alternatively, for oil-fired and gas-fired units, SO_2 emissions may be calculated by multiplying the hourly SO_2 emission rate (in lb/MMBtu), measured by the CEMS required under § 60.49Da, by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(n) Compliance provisions for sources subject to § 60.42Da(c)(1) or (e)(1)(i). The owner or operator shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of § 60.49Da(t)), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

* * * * *

(p) * * *

(5) At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-boiler operating day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

* * * * *

(7) All non-out-of-control CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, non-out-of-control emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-boiler operating day rolling average.

* * * * *

(r) Compliance provisions for sources subject to § 60.45Da. To determine compliance with the NO_X plus CO emissions limit, the owner or operator shall use the procedures specified in paragraphs (r)(1) through (3) of this section.

(1) Calculate NO_X emissions as 1.194×10^{-7} lb/scf-ppm times the average hourly NO_X output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(2) Calculate CO emissions by multiplying the average hourly CO output concentration (measured according to the provisions of § 60.49Da(u), by the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)) or the average hourly net energy output, as applicable.

(3) Calculate NO_X plus CO emissions by summing the NO_X emissions results from paragraph (r)(1) of this section plus the CO emissions results from paragraph (r)(2) of this section.

(s) Affirmative defense for exceedance of emissions limit during malfunction. In response to an action to enforce the standards set forth in paragraph §§ 60.42Da, 60.43Da, 60.44Da, and 60.45Da, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense as specified in paragraphs (s)(1) and (2) of this section. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (s)(2) of this section, and must prove by a preponderance of evidence that:

(i) The excess emissions:

(A) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when the applicable emissions limits were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount, and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(iv) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(2) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (s)(1) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

■ 19. Section 60.49Da is amended as follows:

■ a. By revising paragraphs (a)(1) and (2).

■ b. By revising paragraph (a)(3) introductory text.
■ c. By revising paragraph (a)(3)(ii).
■ d. By revising paragraph (a)(3)(iii)(B).
■ e. By adding paragraph (a)(4).
■ f. By revising paragraph (b) introductory text.
■ g. By revising paragraph (b)(2).
■ h. By revising paragraph (e).
■ i. By revising paragraph (k) introductory text.
■ j. By revising paragraph (k)(3).
■ k. By revising paragraph (l).
■ l. By removing and reserving paragraph (p).
■ m. By removing and reserving paragraph (q).
■ n. By removing and reserving paragraph (r).
■ o. By revising paragraph (t).
■ p. By revising paragraph (u)(1)(iii).
■ q. By revising paragraph (v)(4).

§ 60.49Da Emission monitoring.

(a) * * *

(1) Except as provided for in paragraphs (a)(2) and (4) of this section, the owner or operator of an affected facility subject to an opacity standard, shall install, calibrate, maintain, and operate a COMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the SO_2 control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), or (iv) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

(i) The affected facility uses a fabric filter (baghouse) to meet the standards in § 60.42Da and a bag leak detection system is installed and operated according to the requirements in paragraphs § 60.48Da(o)(4)(i) through (v);

(ii) The affected facility burns only gaseous or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less, and does not use a post-combustion technology to reduce emissions of SO_2 or PM;

(iii) The affected facility meets all of the conditions specified in paragraphs (a)(2)(iii)(A) through (C) of this section.

(A) No post-combustion technology (except a wet scrubber) is used for reducing PM, SO_2, or CO emissions;

(B) Only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur are burned; and

(C) Emissions of CO discharged to the atmosphere are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis as demonstrated by the use of a CEMS measuring CO emissions according to the procedures specified in paragraph (u) of this section; or

(iv) The affected facility uses an ESP and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part.

(3) The owner or operator of an affected facility that meets the conditions in paragraph (a)(2) of this section may, as an alternative to using a COMS, elect to monitor visible emissions using the applicable procedures specified in paragraphs (a)(3)(i) through (iv) of this section. The opacity performance test requirement in paragraph (a)(3)(i) must be conducted by April 29, 2011, within 45 days after stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later.

* * * * *

(ii) Except as provided in paragraph (a)(3)(iii) or (iv) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A–4 of this part performance tests using the procedures in paragraph (a)(3)(i) of this section according to the applicable schedule in paragraphs (a)(3)(ii)(A) through (a)(3)(ii)(C) of this section, as determined by the most recent Method 9 of appendix A–4 of this part performance test results.

(A) If the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(B) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(C) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(iii) * * *

(B) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(4) An owner or operator of an affected facility that is subject to an opacity standard under § 60.42a(b) is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

(i) The affected facility combusts only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.51a(d).

(ii) The owner or operator of the affected facility installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where natural gas and/or liquid fuels (excluding residual oil) with potential SO_2 emissions rates of 26 ng/J (0.060 lb/

MMBtu) or less are the only fuels combusted, as follows:

* * * * *

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere.

* * * * *

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

* * * * *

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross energy output for sources demonstrating compliance with an output-based standard.

* * * * *

(3) For an affected facility generating process steam in combination with electrical generation, the gross energy output is determined according to the definition of ''gross energy output'' specified in § 60.41Da that is applicable to the affected facility.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the calibration drift (CD) assessment, relative accuracy test audit (RATA), and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected facility demonstrating compliance with the input-based emissions limit in § 60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) * * *

(1) * * *

(iii) At a minimum, non-out-of-control 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-boiler operating day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

* * * * *

(v) * * *

(4) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFire database.

* * * * *

■ 20. Section 60.50Da is amended as follows:
■ a. By revising paragraph (b).
■ b. By removing paragraph (g).
■ c. By removing paragraph (h).
■ d. By removing paragraph (i).

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(b) In conducting the performance tests to determine compliance with the PM emissions limits in § 60.42Da, the owner or operator shall meet the requirements specified in paragraphs (b)(1) through (3) of this section.

(1) The owner or operator shall measure filterable PM to determine compliance with the applicable PM emissions limit in § 60.42Da as specified in paragraphs (b)(1)(i) through (ii) of this section.

(i) The dry basis F factor (O_2) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(ii) For the PM concentration, Method 5 of appendix A of this part shall be used for an affected facility that does not use a wet FGD. For an affected facility that uses a wet FGD, Method 5B of appendix A of this part shall be used downstream of the wet FGD.

(A) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ± 14 °C (320 ± 25 °F).

(B) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the O_2 concentration. The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 O_2 traverse points. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(2) In conjunction with a performance test performed according to the requirements in paragraph (b)(1) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after May 3, 2011, shall measure condensable PM using Method 202 of appendix M of part 51.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

* * * * *

■ 21. Section 60.51Da is amended as follows:
■ a. By revising paragraph (a).
■ b. By revising paragraph (b)(5).
■ c. By revising paragraph (d).
■ d. By removing and reserving paragraph (g).
■ e. By revising paragraph (k).

§ 60.51Da Reporting requirements.

(a) For SO_2, NO_X, PM, and NO_X plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) must be reported to the Administrator.

(b) * * *

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, or malfunction.

* * * * *

(d) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) and conducting performance tests using Method 9 of appendix A–4 of this part shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraph (d)(1) of this section.

(1) For each performance test conducted using Method 9 of appendix

A–4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets.

(2) [Reserved]

* * * * *

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (b) and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period.

§60.52Da [Amended]

■ 22. Section 60.52Da is amended by removing and reserving paragraph (a).

Subpart Db—[Amended]

■ 23. Section 60.40b is amended as follows:
■ a. By revising paragraph (c).
■ b. By revising paragraph (h).
■ c. By revising paragraph (i).
■ d. By adding paragraph (1).
■ e. By adding paragraph (m).

§60.40b Applicability and delegation of authority.

* * * * *

(c) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

* * * * *

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, subpart AAAA, or subpart CCCC of this part is not subject to this subpart.

(i) Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (*i.e.* heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (*i.e.* heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

* * * * *

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

(m) Temporary boilers are not subject to this subpart.

24. Section 60.41b is amended by revising the definition of ''distillate oil'', and adding the definition of ''temporary boiler'' in alphabetical order to read as follows:

§60.41b Definitions.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17), diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see §60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see §60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see §60.17).

* * * * *

Temporary boiler means any gaseous or liquid fuel-fired steam generating unit that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

■ 25. Section 60.43b is amended by revising paragraph (f) to read as follows:

§60.43b Standard for particulate matter (PM).

* * * * *

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

* * * * *

■ 26. Section 60.44b is amended as follows:
■ a. The section heading is revised.
■ b. By revising paragraph (b) introductory text.
■ c. By revising paragraph (c).
■ d. By revising paragraph (d).
■ e. By revising paragraph (e).
■ f. By revising paragraph (l)(1).

§60.44b Standard for nitrogen oxides (NO_X).

* * * * *

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

* * * * *

(c) Except as provided under paragraph (d) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section. This standard does not apply to an affected facility that is subject to and in compliance with a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, natural gas (or any combination of the three).

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas and/or distillate oil with a potential SO_2 emissions rate of 26 ng/J (0.060 lb/MMBtu) or less with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas, distillate oil, or a mixture of these fuels of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas, distillate oil, or a mixture of these fuels.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts only coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

* * * * *

(l) * * *

(1) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal, oil, or natural gas (or any combination of the three), alone or with any other fuels. The affected facility is not subject to this limit if it is subject to and in compliance with a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas (or any combination of the three); or

* * * * *

■ 27. Section 60.46b is amended by revising paragraph (j)(14) to read as follows:

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

* * * * *

(j) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

■ 28. Section 60.48b is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraphs (a)(1)(i) through (iii) .

■ c. By revising paragraph (a)(2)(ii).

■ d. By revising paragraph (j) introductory text.

■ e. By revising paragraph (j)(5).

■ f. By revising paragraph (j)(6).

■ g. By adding paragraph (j)(7).

■ h. By adding paragraph (l).

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under § 60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

* * * * *

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section § 60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section § 60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

* * * * *

(l) An owner or operator of an affected facility that is subject to an opacity standard under § 60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.49b(h).

■ 29. Section 60.49b is amended by revising paragraph (r)(1) to read as follows.

§ 60.49b Reporting and recordkeeping requirements.

* * * * *

(r) * * *

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in § 60.42b(j) or § 60.42b(k) shall obtain and maintain at the affected facility fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

* * * * *

Subpart Dc—[Amended]

■ 30. Section 60.40c is amended as follows:

■ a. By revising paragraph (a).
■ b. By revising paragraph (e).
■ c. By revising paragraph (f).
■ d. By revising paragraph (g).
■ e. By adding paragraph (h).
■ f. By adding paragraph (i).

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

* * * * *

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

■ 31. Section 60.41c is amended as follows:

■ a. By removing the definition of ‘‘Cogeneration.’’
■ b. By revising the definition of ‘‘Distillate oil.’’
■ c. By adding a definition of ‘‘Temporary boiler’’ in alphabetical order.

§ 60.41c Definitions.

* * * * *

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

* * * * *

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

* * * * *

■ 32. Section 60.42c is amended as follows:

■ a. By revising paragraph (c)(1) and (3).

■ b. By revising paragraph (d).

■ c. By revising paragraph (e)(1)(ii).

■ d. By revising paragraph (h) introductory text.

■ e. By revising paragraph (h)(3).

■ f. By adding paragraph (h)(4).

§ 60.42c Standard for sulfur dioxide (SO_2).

* * * * *

(c) * * *

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

* * * * *

(3) Affected facilities located in a noncontinental area; or

* * * * *

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) * * *

(1) * * *

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

* * * * *

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

* * * * *

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

* * * * *

■ 33. Section 60.43c is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraph (b) introductory text.

■ c. By revising paragraph (c).

■ d. By revising paragraphs (e)(1), (3), and (4).

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

* * * * *

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

* * * * *

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

* * * * *

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

* * * * *

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur

or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

■ 34. Section 60.45c is amended as follows:

■ a. By revising paragraph (c)(14).

■ b. By revising paragraph (d).

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

* * * * *

(c) * * *

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

■ 35. Section 60.47c is amended as follows:

■ a. By revising paragraph (a) introductory text.

■ b. By revising paragraphs (a)(1)(i) through (iii).

■ c. By revising paragraph (a)(2)(ii).

■ d. By revising paragraph (f).

■ e. By removing paragraph (g).

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A–4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A–4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) * * *

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A–4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

* * * * *

(2) * * *

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

* * * * *

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

Subpart HHHH—[Removed and Reserved]

■ 36. Subpart HHHH is removed and reserved.

PART 63—[AMENDED]

■ 37. The authority citation for 40 CFR Part 63 continues to read as follows:

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

Subpart A—[Amended]

■ 38. Section 63.14 is amended as follows:

■ a. By adding paragraphs (b)(19) and (20).

■ b. By adding paragraphs (b)(22) and (23).

■ c. By adding paragraphs (b)(69) through (72).

■ d. By revising paragraph (i)(1).

§ 63.14 Incorporation by reference.

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(b) * * *

(19) ASTM D95–05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(i).

(20) ASTM Method D388–05, Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.10042.

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(22) ASTM Method D396–10, Standard Specification for Fuel Oils, including Appendix X1, approved October 1, 2010, IBR approved for § 63.10042.

(23) ASTM D4006–11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(ii).

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(69) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, approved June 1, 2011, IBR approved for § 63.10005(i)(4)(iv).

(70) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, approved May 1, 2010, IBR approved for § 63.10005(i)(4)(iii).

(71) ASTM D6348–03 (Reapproved 2010), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, approved October 1, 2010, IBR approved for table 1 to subpart UUUUU of this part, table 2 to subpart UUUUU of this part, table 5 to subpart UUUUU of this part, and appendix B to subpart UUUUU of this part.

(72) ASTM D6784–02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 5 to subpart UUUUU of this part, and appendix A to subpart UUUUU of this part.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, ‘‘Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus],’’ IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, table 4 to subpart JJJJJJ of this part, and table 5 to subpart UUUUU of this part.

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■ 39. Part 63 is amended by adding subpart UUUUU to read as follows:

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

Sec.

What This Subpart Covers

Emission Limitations and Work Practice Standards

General Compliance Requirements

Testing and Initial Compliance Requirements

Continuous Compliance Requirements

Notifications, Reports, and Records

Other Requirements and Information

Tables to Subpart UUUUU of Part 63

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

What This Subpart Covers

§ 63.9980 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in § 63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations.

§ 63.9981 Am I subject to this subpart?

You are subject to this subpart if you own or operate a coal-fired EGU or an oil-fired EGU as defined in § 63.10042 of this subpart.

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, and existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

(1) The affected source of this subpart is the collection of all existing coal- or oil-fired EGUs, as defined in 63.10042, within a subcategory.

(2) The affected source of this subpart is each new or reconstructed coal- or oil-fired EGU as defined in 63.10042.

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011, and you meet the applicability criteria at the time you commence construction.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after May 3, 2011, and you meet the applicability criteria at the time you commence reconstruction.

(d) An EGU is existing if it is not new or reconstructed. An existing electric steam generating unit that meets the applicability requirements after the effective date of this final rule due to a change process (*e.g.,* fuel or utilization) is considered to be an existing source under this subpart.

§ 63.9983 Are any EGUs not subject to this subpart?

The types of electric steam generating units listed in paragraphs (a) through (d) of this section are not subject to this subpart.

(a) Any unit designated as a stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and combusts natural gas for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but did not fire coal or oil for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

(d) Any electric steam generating unit combusting solid waste is a solid waste incineration unit subject to standards established under sections 129 and 111 of the Clean Air Act.

§ 63.9984 When do I have to comply with this subpart?

(a) If you have a new or reconstructed EGU, you must comply with this subpart by April 16, 2012 or upon startup of your EGU, whichever is later, and as further provided for in § 63.10005(g).

(b) If you have an existing EGU, you must comply with this subpart no later than April 16, 2015.

(c) You must meet the notification requirements in § 63.10030 according to the schedule in § 63.10030 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(d) An electric steam generating unit that does not meet the definition of an EGU subject to this subpart on April 16, 2012 for new sources or April 16, 2015 for existing sources must comply with the applicable existing source provisions of this subpart on the date such unit meets the definition of an EGU subject to this subpart.

(e) If you own or operate an electric steam generating unit that is exempted from this subpart under § 63.9983(d), if the manner of operating the unit changes such that the combustion of waste is discontinued and the unit becomes a coal-fired or oil-fired EGU (as defined in § 63.10042), you must be in compliance with this subpart on April 16, 2015 or on the effective date of the switch from waste combustion to coal or oil combustion, whichever is later.

(f) You must demonstrate that compliance has been achieved, by conducting the required performance tests and other activities, no later than 180 days after the applicable date in paragraph (a), (b), (c), (d), or (e) of this section.

§ 63.9985 What is a new EGU?

(a) A new EGU is an EGU that meets any of the criteria specified in paragraph (a)(1) through (a)(2) of this section.

(1) An EGU that commenced construction after May 3, 2011.

(2) An EGU that commenced reconstruction or modification after May 3, 2011.

(b) [Reserved]

Emission Limitations and Work Practice Standards

§ 63.9990 What are the subcategories of EGUs?

(a) Coal-fired EGUs are subcategorized as defined in paragraphs (a)(1) through (a)(2) of this section and as defined in § 63.10042.

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and

(2) EGUs designed for low rank virgin coal.

(b) Oil-fired EGUs are subcategorized as noted in paragraphs (b)(1) through (b)(4) of this section and as defined in § 63.10042.

(1) Continental liquid oil-fired EGUs

(2) Non-continental liquid oil-fired EGUs,

(3) Limited-use liquid oil-fired EGUs, and

(4) EGUs designed to burn solid oil-derived fuel.

(c) IGCC units combusting either gasified coal or gasified solid oil-derived fuel. For purposes of compliance, monitoring, recordkeeping, and reporting requirements in this subpart, IGCC units are subject in the same manner as coal-fired units and solid oil-derived fuel-fired units, unless otherwise indicated.

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

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Table 1 through 3 to this subpart that applies to your EGU, for each EGU at your source, except as provided under § 63.10009.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your EGU.

(b) As provided in § 63.6(g), the Administrator may approve use of an alternative to the work practice standards in this section.

(c) You may use the alternate SO_2 limit in Tables 1 and 2 to this subpart only if your coal-fired EGU:

(1) Has a system using wet or dry flue gas desulfurization technology and SO_2 continuous emissions monitoring system (CEMS) installed on the unit; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology installed on the unit consistent with § 63.10000(b).

General Compliance Requirements

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

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, you are required to meet the work practice requirements in Table 3 to this subpart during periods of startup or shutdown.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(c)(1) For coal-fired units and solid oil-derived fuel-fired units, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(i) For a coal-fired or solid oil-derived fuel-fired EGU or IGCC EGU, you may conduct the initial performance testing in accordance with § 63.10005(h), to determine whether the unit qualifies as a low emitting EGU (LEE) for one or more applicable emissions limits, with two exceptions:

(A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration, and

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-fired fuel fired EGU or IGCC EGU is new.

(ii) 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.

(iii) 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.

(iv) If your coal-fired or solid oil-derived fuel-fired EGU or IGCC 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 compliance performance testing repeated quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total non-mercury HAP metals, individual non-mercury HAP metals or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) You may also opt to install and operate a particulate matter CEMS certified in accordance with Performance Specification 11 and Procedure 2 of 40 CFR part 60, Appendices B and F, respectively, in accordance with § 63.10010(i).

(v) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for hydrogen chloride (HCl), you may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B to this subpart. As an alternative to HCl CEMS, you may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If your EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), you may apply a second alternative to HCl CEMS by installing and operating a sulfur dioxide (SO_2) CEMS installed and operated in accordance with part 75 of this chapter to demonstrate compliance with the applicable SO_2 emissions limit.

(vi) If your coal-fired or solid oil-derived fuel-fired EGU does not qualify as a LEE for Hg, you must demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with appendix A to this subpart.

(2) For liquid oil-fired EGUs, except limited use liquid oil-fired EGUs, initial performance testing is required for all pollutants, to demonstrate compliance with the applicable emission limits.

(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.

(ii) If your existing 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 performance testing conducted quarterly.

(A) If you elect to use PM CPMS, you will establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply: total HAP metals, individual HAP metals, or filterable PM. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. If you elect to use a PM CPMS, you must repeat the performance test at least annually for the selected pollutant limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(B) If you elect to use a PM CEMS, you will use the CEMS in accordance with § 63.10010(i) to demonstrate initial and continuous compliance with the filterable PM emission limit.

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance by conducting periodic quarterly performance stack tests for HCl and HF. If you elect to demonstrate compliance through quarterly performance testing, then you must also develop a site-specific monitoring plan to ensure that the operations of the unit remain consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

(iv) If your unit qualifies as a limited-use liquid oil-fired as defined in § 63.10042, then you are not subject to the emission limits in Tables 1 and 2, but must comply with the performance tune-up work practice requirements in Table 3.

(d)(1) If you demonstrate compliance with any applicable emissions limit through use of a continuous monitoring system (CMS), where a CMS includes a continuous parameter monitoring system (CPMS) as well as a continuous emissions monitoring system (CEMS), you must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation (where applicable) of your CMS. This requirement also applies to you if you petition the Administrator for alternative monitoring parameters under § 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B to part 60 or part 75 of this chapter, and that meet the requirements of § 63.10010. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in your site-specific monitoring plan. The monitoring plan must address the provisions in paragraphs (d)(2) through (5) of this section.

(2) The site-specific monitoring plan shall include the information specified in paragraphs (d)(5)(i) through (d)(5)(vii) of this section. Alternatively, the requirements of paragraphs (d)(5)(i) through (d)(5)(vii) are considered to be met for a particular CMS or sorbent trap monitoring system if:

(i) The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to part 75 of this chapter, or appendix A or B to this subpart; and

(ii) The recordkeeping and reporting requirements of part 75 of this chapter, or appendix A or B to this subpart, that pertain to the CMS are met.

(3) If requested by the Administrator, you must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of § 63.10010 (*e.g.,* if the CMS was previously certified under another program).

(4) You must operate and maintain the CMS according to the site-specific monitoring plan.

(5) The provisions of the site-specific monitoring plan must address the following items:

(i) Installation of the CEMS 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 CPMS installations, follow the procedures in § 63.10010(h).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Schedule for conducting initial and periodic performance evaluations.

(iv) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations), including ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(v) On-going operation and maintenance procedures, in accordance with the general requirements of §§ 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

(vi) Conditions that define a CMS that is out of control consistent with § 63.8(c)(7)(i) and for responding to out of control periods consistent with §§ 63.8(c)(7)(ii) and (c)(8).

(vii) On-going recordkeeping and reporting procedures, in accordance with the general requirements of §§ 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under this subpart.

(e) As part of your demonstration of continuous compliance, you must perform periodic tune-ups of your EGU(s), according to § 63.10021(e).

(f) You are subject to the requirements of this subpart for at least 6 months following the last date you met the definition of an EGU subject to this subpart (*e.g.*, 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). You may opt to remain subject to the provisions of this subpart beyond 6 months after the last date you met the definition of an EGU subject to this subpart, unless you are a solid waste incineration unit subject to standards under CAA section 129 (*e.g.*, 40 CFR part 60, subpart CCCC (New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incineration Units, or Subpart DDDD (Emissions Guidelines (EG) for Existing Commercial and Industrial Solid Waste Incineration Units). Notwithstanding the provisions of this subpart, an EGU that starts combusting solid waste is immediately subject to standards under CAA section 129 and the EGU remains subject to those standards until the EGU no longer meets the definition of a solid waste incineration unit consistent with the provisions of the applicable CAA section 129 standards.

(g) If you no longer meet the definition of an EGU subject to this subpart you must be in compliance with any newly applicable standards on the date you are no longer subject to this subpart. The date you are no longer subject to this subpart is a date selected by you, that must be at least 6 months from the date that you last met the definition of an EGU subject to this subpart or the date you begin combusting solid waste, consistent with § 63.9983(d). Your source must remain in compliance with this subpart until the date you select to cease complying with this subpart or the date you begin combusting solid waste, whichever is earlier.

(h)(1) If you own or operate an EGU that does not meet the definition of an EGU subject to this subpart on April 16, 2015, and you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart, you are subject to the provisions of this subpart, including, but not limited to, the emission limitations and the monitoring requirements, as of the first day you meet the definition of an EGU subject to this subpart. You must complete all initial compliance demonstrations for this subpart applicable to your EGU within 180 days after you commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart.

(2) You must provide 30 days prior notice of the date you intend to commence or recommence operations that cause you to meet the definition of an EGU subject to this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU, the location of the facility, the unit(s) that will commence or recommence operations that will cause the unit(s) to meet the definition of an EGU subject to this subpart, and the date of the notice;

(ii) The 40 CFR part 60, part 62, or part 63 subpart and subcategory currently applicable to your unit(s), and the subcategory of this subpart that will be applicable after you commence or recommence operation that will cause the unit(s) to meet the definition of an EGU subject to this subpart;

(iii) The date on which you became subject to the currently applicable emission limits;

(iv) The date upon which you will commence or recommence operations that will cause your unit to meet the definition of an EGU subject to this subpart, consistent with paragraph (f) of this section.

(i)(1) If you own or operate an EGU subject to this subpart, and it has been at least 6 months since you operated in a manner that caused you to meet the definition of an EGU subject to this subpart, you may, consistent with paragraph (g) of this section, select the date on which your EGU will no longer be subject to this subpart. You must be in compliance with any newly applicable section 112 or 129 standards on the date you selected.

(2) You must provide 30 days prior notice of the date your EGU will cease complying with this subpart. The notification must identify:

(i) The name of the owner or operator of the EGU(s), the location of the facility, the EGU(s) that will cease complying with this subpart, and the date of the notice;

(ii) The currently applicable subcategory under this subpart, and any 40 CFR part 60, part 62, or part 63 subpart and subcategory that will be applicable after you cease complying with this subpart;

(iii) The date on which you became subject to this subpart;

(iv) The date upon which you will cease complying with this subpart, consistent with paragraph (g) of this section.

(j) All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart.

(k) All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause your EGU to meet the definition of an EGU subject to this subpart must be installed and operational as of the date your source ceases to be or becomes subject to this subpart. All calibration and drift checks must be performed as of the date your source ceases to be or becomes subject to this subpart. You must also comply with provisions of §§ 63.10010, 63.10020, and 63.10021 of this subpart. Relative accuracy tests must be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under this subpart.

§ 63.10001 Affirmative defense for exceedence of emission limit during malfunction.

In response to an action to enforce the standards set forth in § 63.9991 you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the affected source experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction or, if it is not possible to determine within two business days whether the malfunction caused or contributed to an exceedance, no later than two business days after the owner or operator knew or should have known that the malfunction caused or contributed to an exceedance, but, in no event later than two business days after the end of the averaging period, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.9991 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

Testing and Initial Compliance Requirements

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

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (e.g., a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the applicable date in paragraph (f) of this section for tune-up work practices for existing EGUs, in § 63.9984 for other requirements for existing EGUs, and in paragraph (g) of this section for all requirements for new EGUs.

(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. 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. Also, if you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the test period.

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.*, an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test consists of 30 boiler operating days of data collected by the initial compliance demonstration date specified in § 63.10005 with the certified monitoring system.

(i) The 30-boiler operating day CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

(ii) If you choose to comply with an electrical output-based emission limit, you must collect hourly electrical load data during the performance 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 § 63.10007 and Table 5 to this subpart. 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 § 63.9984, provided that the following conditions are fully met:

(1) For a performance test based on stack test data, the test was conducted no more than 12 calendar months prior to the date on which compliance is required as specified in § 63.9984;

(2) For a performance test based on data from a certified CEMS or sorbent trap monitoring system, the test consists of all valid data CMS data recorded in the 30 boiler operating days immediately preceding that date;

(3) The performance test was conducted in accordance with all applicable requirements in § 63.10007 and Table 5 to this subpart;

(4) A record of all parameters needed to convert pollutant concentrations to units of the emission standard (e.g., stack flow rate, diluent gas concentrations, hourly electrical loads) is available for the entire performance test period; and

(5) For each performance test based on stack test data, you certify, and keep documentation demonstrating, that the EGU configuration, control devices, and fuel(s) have remained consistent with conditions since the prior performance test was conducted.

(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.

(d) *CMS requirements.* If, for a particular emission or operating limit, you are required to (or elect to) demonstrate initial compliance using a continuous monitoring system, the CMS must pass a performance evaluation prior to the initial compliance demonstration. If a CMS has been previously certified under another state or federal program and is continuing to meet the on-going quality-assurance (QA) requirements of that program, then, provided that the certification and QA provisions of that program meet the applicable requirements of §§ 63.10010(b) through (h), an additional performance evaluation of the CMS is not required under this subpart.

(1) For an affected coal-fired, solid oil-derived fuel-fired, or liquid oil-fired EGU, you may demonstrate initial compliance with the applicable SO_2, HCl, or HF emissions limit in Table 1 or 2 of this subpart through use of an SO_2, HCl, or HF CEMS installed and operated in accordance with part 75 of this chapter or Appendix B to this subpart, as applicable. You may also demonstrate compliance with a filterable PM emission limit in Table 1 or 2 of this subpart through use of a PM CEMS installed, certified, and operated in accordance with § 63.10010(i). Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS data, expressed in units of the standard (see § 63.10007(e)), meets the applicable SO_2, PM, HCl, or HF emissions limit in Table 1 or 2 to this subpart. Use Equation 19–19 of Method 19 in appendix A–7 to part 60 of this chapter to calculate the 30-boiler operating day average emissions rate. (Note: for this calculation, the term E_{hj} in Equation 19–19 must be in the same units of measure as the applicable HCl or HF emission limit in Table 1 or 2 to this subpart).

(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:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the pollutant with which you choose to comply.

(iii) You must repeat the performance test annually for the selected pollutant emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this

subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30-boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) For affected liquid oil-fired EGUs that demonstrate compliance with the applicable emission limits for HCl or HF listed in Table 1 or 2 to this subpart using quarterly testing and continuous monitoring with a CMS:

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984 for existing EGUs and in paragraph (g) of this section for new EGUs.

(ii) You must demonstrate continuous compliance with the CMS site-specific operating limit that corresponding to the results of the performance test demonstrating compliance with the HCl or HF emissions limit.

(iii) You must repeat the performance test annually for the HCl or HF emissions limit and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(e) *Tune-ups.* All affected EGUs are subject to the work practice standards in Table 3 of this subpart. As part of your initial compliance demonstration, you must conduct a performance tune-up of your EGU according to § 63.10021(e).

(f) For existing affected sources a tune-up may occur prior to April 16, 2012, so that existing sources without neural networks have up to 42 calendar months (3 years from promulgation plus 180 days) or, in the case of units employing neural network combustion controls, up to 54 calendar months (48 months from promulgation plus 180 days) after the date that is specified for your source in § 63.9984 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 9 to this subpart to demonstrate compliance with this requirement. If a tune-up occurs prior to such date, the source must maintain adequate records to show that the tune-up met the requirements of this standard.

(g) If your new or reconstructed affected source commenced construction or reconstruction between May 3, 2011, and July 2, 2011, you must demonstrate initial compliance with either the proposed emission limits or the promulgated emission limits no later than 180 days after April 16, 2012 or within 180 days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(1) For the new or reconstructed affected source described in this paragraph (g), if you choose to comply with the proposed emission limits when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits within 3 years after April 16, 2012 or within 3 years after startup of the affected source, whichever is later.

(2) If your new or reconstructed affected source commences construction or reconstruction after April 16, 2012, you must demonstrate initial compliance with the promulgated emission limits no later than 180 days after startup of the source.

(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. You may not pursue this compliance option if your existing EGU is equipped with an acid gas scrubber and has a main stack and bypass stack exhaust configuration.

(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), and if those data demonstrate:

(i) For all pollutants except Hg, performance test emissions results less than 50 percent of the applicable emissions limits in Table 1 or 2 to this subpart for all required testing for 3 consecutive years; or

(ii) For Hg emissions from an existing EGU, either:

(A) Average emissions less than 10 percent of the applicable Hg emissions limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh); or

(B) Potential Hg mass emissions of 29.0 or fewer pounds per year and compliance with the applicable Hg emission limit in Table 2 to this subpart (expressed either in units of lb/TBtu or lb/GWh).

(2) For all pollutants except Hg, you must conduct all required performance tests described in § 63.10007 to demonstrate that a unit qualifies for LEE status.

(i) When conducting emissions testing to demonstrate LEE status, you must increase the minimum sample volume specified in Table 1 or 2 nominally by a factor of two.

(ii) Follow the instructions in § 63.10007(e) and Table 5 to this subpart to convert the test data to the units of the applicable standard.

(3) For Hg, you must conduct a 30-boiler operating day performance test using Method 30B in appendix A–8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within the 10 percent centroidal area of the duct at a location that meets Method 1 in appendix A–1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures), under all process operating conditions. You may use a pair of sorbent traps to sample the stack gas for no more than 10 days.

(i) Depending on whether you intend to assess LEE status for Hg in terms of the lb/TBtu or lb/GWh emission limit in Table 2 to this subpart or in terms of the annual Hg mass emissions limit of 29.0 lb/year, you will have to collect some or all of the following data during the 30-boiler operating day test period (see paragraph (h)(3)(iii) of this section):

(A) Diluent gas (CO_2 or O_2) data, using either Method 3A in appendix A–3 to part 60 of this chapter or a diluent gas monitor that has been certified according to part 75 of this chapter.

(B) Stack gas flow rate data, using either Method 2, 2F, or 2G in appendices A–1 and A–2 to part 60 of this chapter, or a flow rate monitor that has been certified according to part 75 of this chapter.

(C) Stack gas moisture content data, using either Method 4 in appendix A–1 to part 60 of this chapter, or a moisture monitoring system that has been certified according to part 75 of this chapter. Alternatively, an appropriate fuel-specific default moisture value from § 75.11(b) of this chapter may be used in the calculations or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units.

(D) Hourly electrical load data (megawatts), from facility records.

(ii) If you use CEMS to measure CO_2 (or O_2) concentration, and/or flow rate, and/or moisture, record hourly average values of each parameter throughout the 30-boiler operating day test period. If you opt to use EPA reference methods rather than CEMS for any parameter, you must perform at least one representative test run on each operating day of the test period, using the applicable reference method.

(iii) Calculate the average Hg concentration, in µg/m^3 (dry basis), for the 30-boiler operating day performance test, as the arithmetic average of all Method 30B sorbent trap results. Also calculate, as applicable, the average values of CO_2 or O_2 concentration, stack gas flow rate, stack gas moisture content, and electrical load for the test period. Then:

(A) To express the test results in units of lb/TBtu, follow the procedures in § 63.10007(e). Use the average Hg concentration and diluent gas values in the calculations.

(B) To express the test results in units of lb/GWh, use Equations A–3 and A–4 in section 6.2.2 of appendix A to this subpart, replacing the hourly values ‘‘C_h’’, ‘‘Q_h’’, ‘‘B_{ws}’’ and ‘‘$(MW)_h$’’ with the average values of these parameters from the performance test.

(C) To calculate pounds of Hg per year, use one of the following methods:

(*1*) Multiply the average lb/TBtu Hg emission rate (determined according to paragraph (h)(3)(iii)(A) of this section) by the maximum potential annual heat input to the unit (TBtu), which is equal to the maximum rated unit heat input (TBtu/hr) times 8,760 hours. If the maximum rated heat input value is expressed in units of MMBtu/hr, multiply it by 10^6 to convert it to TBtu/hr; or

(*2*) Multiply the average lb/GWh Hg emission rate (determined according to paragraph (h)(3)(iii)(B) of this section) by the maximum potential annual electricity generation (GWh), which is equal to the maximum rated electrical output of the unit (GW) times 8,760 hours. If the maximum rated electrical output value is expressed in units of MW, multiply it by 10^3 to convert it to GW; or

(*3*) If an EGU has a federally-enforceable permit limit on either the annual heat input or the number of annual operating hours, you may modify the calculations in paragraph (h)(3)(iii)(C)(1) of this section by replacing the maximum potential annual heat input or 8,760 unit operating hours with the permit limit on annual heat input or operating hours (as applicable).

(4) For a group of affected units that vent to a common stack, you may either assess LEE status for the units individually by performing a separate emission test of each unit in the duct leading from the unit to the common stack, or you may perform a single emission test in the common stack. If you choose the common stack testing option, the units in the configuration qualify for LEE status if:

(i) The emission rate measured at the common stack is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section (with some modifications), are less than or equal to 29.0 pounds times the number of units sharing the common stack. Base your calculations on the combined heat input capacity of all units sharing the stack (i.e., either the combined maximum rated value or, if applicable, a lower combined value restricted by permit conditions or operating hours).

(5) For an affected unit with a multiple stack or duct configuration in which the exhaust stacks or ducts are downstream of all emission control devices, you must perform a separate emission test in each stack or duct. The unit qualifies for LEE status if:

(i) The emission rate, based on all test runs performed at all of the stacks or ducts, is less than 50 percent (10 percent for Hg) of the applicable emission limit in Table 1 or 2 to this subpart; or

(ii) For Hg from an existing EGU, the applicable Hg emission limit in Table 2 to this subpart is met and the potential annual mass emissions, calculated according to paragraph (h)(3)(iii) of this section, are less than or equal to 29.0 pounds. Use the average Hg emission rate from paragraph (h)(5)(i) of this section in your calculations.

(i) Liquid-oil fuel moisture measurement. If your EGU combusts liquid fuels, if your fuel moisture content is no greater than 1.0 percent by weight, and if you would like to demonstrate initial and ongoing compliance with HCl and HF emissions limits, you must meet the requirements of paragraphs (i)(1) through (5) of this section.

(1) Measure fuel moisture content of each shipment of fuel if your fuel arrives on a batch basis; or

(2) Measure fuel moisture content daily if your fuel arrives on a continuous basis; or

(3) Obtain and maintain a fuel moisture certification from your fuel supplier.

(4) Use one of the following methods to determine fuel moisture content:

(i) ASTM D95–05 (Reapproved 2010), ‘‘Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation,’’ or

(ii) ASTM D4006–11, ‘‘Standard Test Method for Water in Crude Oil by Distillation,’’ including Annex A1 and Appendix A1, or

(iii) ASTM D4177–95 (Reapproved 2010), ‘‘Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,’’ including Annexes A1 through A6 and Appendices X1 and X2, or

(iv) ASTM D4057–06 (Reapproved 2011), ‘‘Standard Practice for Manual Sampling of Petroleum and Petroleum Products,’’ including Annex A1.

(5) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

(j) Startup and shutdown for coal-fired or solid oil derived-fired units. You must follow the requirements given in Table 3 to this subpart.

(k) You must submit a Notification of Compliance Status summarizing the results of your initial compliance demonstration, as provided in § 63.10030.

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

(a) For liquid oil-fired, solid oil-derived fuel- and coal-fired EGUs and IGCC units using PM CPMS 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.

(b) For affected units meeting the LEE requirements of § 63.10005(h), you must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 and § 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur:

(1) For all pollutant emission limits except for Hg, you must conduct emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1).

(2) For Hg, you must install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with appendix A to this subpart, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, you must conduct Hg emissions testing quarterly, except as otherwise provided in § 63.10021(d)(1). You must have 3 calendar years of testing and CEMS or

sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status.

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emission limit, for liquid oil-fired EGUs, you must conduct all applicable periodic emissions tests for filterable PM, or individual or total HAP metals emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(d) Except where paragraph (b) of this section applies, for solid oil-derived fuel- and coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, you must conduct all applicable periodic HCl emissions tests according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1).

(e) Except where paragraph (b) of this section applies, for liquid oil-fired EGUs without HCl CEMS, HF CEMS, or HCl and HF CEMS, you must conduct all applicable emissions tests for HCl, HF, or HCl and HF emissions according to Table 5 to this subpart and § 63.10007 at least quarterly, except as otherwise provided in § 63.10021(d)(1), and conduct site-specific monitoring under a plan as provided for in § 63.10000(c)(2)(iii).

(f) Unless you follow the requirements listed in paragraphs (g) and (h) of this section, performance tests required at least every 3 calendar years must be completed within 35 to 37 calendar months after the previous performance test; performance tests required at least every year must be completed within 11 to 13 calendar months after the previous performance test; and performance tests required at least quarterly must be completed within 80 to 100 calendar days after the previous performance test, except as otherwise provided in § 63.10021(d)(1).

(g) If you elect to demonstrate compliance using emissions averaging under § 63.10009, you must continue to conduct performance stack tests at the appropriate frequency given in section (c) through (f) of this section.

(h) If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if you choose to reapply for LEE status, you must conduct performance tests at the appropriate frequency given in section (c) through (e) of this section for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria.

(i) If you are required to meet an applicable tune-up work practice standard, you must conduct a performance tune-up according to § 63.10021(e).

(1) For EGUs not employing neural network combustion optimization during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 36 calendar months after the previous performance tune-up.

(2) For EGUs employing neural network combustion optimization systems during normal operation, each performance tune-up specified in § 63.10021(e) must be no more than 48 calendar months after the previous performance tune-up.

(j) You must report the results of performance tests and performance tune-ups within 60 days after the completion of the performance tests and performance tune-ups. The reports for all subsequent performance tests must include all applicable information required in § 63.10031.

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

(a) Except as otherwise provided in this section, you must conduct all required performance tests according to § 63.7(d), (e), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(1) If you use CEMS (Hg, HCl, SO_2, or other) to determine compliance with a 30-boiler operating day rolling average emission limit, you must collect data for all nonexempt unit operating conditions (see § 63.10011(g) and Table 3 to this subpart).

(2) If you conduct performance testing with test methods in lieu of continuous monitoring, operate the unit at maximum normal operating load conditions during each periodic (*e.g.,* quarterly) performance test. 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.

(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, 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.

(b) You must conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements in Table 5 to this subpart.

(c) If you choose to comply with the filterable PM emission limit and demonstrate continuous performance using a PM CPMS for an applicable emission limit as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b)(5) 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.

(d) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, you must conduct a minimum of three separate test runs for each performance test, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling time or volume specified in Table 1 or 2 to this subpart. Sections 63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or sorbent trap monitoring systems, and for conducting emission tests for LEE qualification.

(e) To use the results of performance testing to determine compliance with the applicable emission limits in Table 1 or 2 to this subpart, proceed as follows:

(1) Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (*e.g.,* laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (*e.g.,* analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

(2) If the limits are expressed in lb/MMBtu or lb/TBtu, you must use the F-factor methodology and equations in

sections 12.2 and 12.3 of EPA Method 19 in appendix A–7 to part 60 of this chapter. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Use the following factors to convert the pollutant concentrations measured during the initial performance tests to units of lb/scf, for use in the applicable Method 19 equations:

(i) Multiply SO_2 ppm by 1.66×10^{-7};

(ii) Multiply HCl ppm by 9.43×10^{-8};

(iii) Multiply HF ppm by 5.18×10^{-8};

(iv) Multiply HAP metals concentrations (mg/dscm) by 6.24×10^{-8}; and

(v) Multiply Hg concentrations (μg/scm) by 6.24×10^{-11}.

(3) To determine compliance with emission limits expressed in lb/MWh or lb/GWh, you must first calculate the pollutant mass emission rate during the performance test, in units of lb/h. For Hg, if a CEMS or sorbent trap monitoring system is used, use Equation A–2 or A–3 in appendix A to this subpart (as applicable). In all other cases, use an equation that has the general form of Equation A–2 or A–3, replacing the value of K with 1.66×10^{-7} lb/scf-ppm for SO_2, 9.43×10^{-8} lb/scf-ppm for HCl (if an HCl CEMS is used), 5.18×10^{-8} lb/scf-ppm for HF (if an HF CEMS is used), or 6.24×10^{-8} lb-scm/mg-scf for HAP metals and for HCl and HF (when performance stack testing is used), and defining C_h as the average SO_2, HCl, or HF concentration in ppm, or the average HAP metals concentration in mg/dscm. This calculation requires stack gas volumetric flow rate (scfh) and (in some cases) moisture content data (see §§ 63.10005(h)(3) and 63.10010). Then, if the applicable emission limit is in units of lb/GWh, use Equation A–4 in appendix A to this subpart to calculate the pollutant emission rate in lb/GWh. In this calculation, define $(M)_h$ as the calculated pollutant mass emission rate for the performance test (lb/h), and define $(MW)_h$ as the average electrical load during the performance test (megawatts). If the applicable emission limit is in lb/MWh rather than lb/GWh, omit the 10^3 term from Equation A–4 to determine the pollutant emission rate in lb/MWh.

(f) Upon request, you shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of this section.

§ 63.10008 [Reserved]

§ 63.10009 May I use emissions averaging to comply with this subpart?

(a) *General eligibility.* (1) You may use emissions averaging as described in paragraph (a)(2) of this section as an alternative to meeting the requirements of § 63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if:

(i) You have more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control); and

(ii) You use CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance.

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the ‘‘unit designed for coal ≥ 8,300 Btu/lb’’ subcategory are equal to or less than 1.0 lb/TBtu or 1.1E–2 lb/GWh or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2, according to the procedures in this section. Note that except for Hg emissions from EGUs in the ‘‘unit designed for coal ≥ 8,300 Btu/lb’’ subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for Hg from EGUs in the ‘‘unit designed for coal ≥ 8,300 Btu/lb’’ subcategory is 90 days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-day) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross electrical output basis (MWh or GWh, as appropriate for the pollutant).

(ii) You may not mix bases within your EGU emissions averaging group.

(iii) You may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see paragraph (m) of this section).

(b) *Equations.* Use the following equations when performing calculations for your EGU emissions averaging group:

(1) *Group eligibility equations.*

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Herm_i \times Rmm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Rmt_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n} Rmm_i\right]_p\right] + \sum_{i=1}^{m} Rmt_i} \quad (Eq.\ 1a)$$

Where:

WAERm = Weighted average emissions rate maximum in terms of lb/heat input or lb/gross electrical output,

$Herm_i$ = Hourly emissions rate (*e.g.,* lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i,

Rmm_i = Maximum rated heat input or gross electrical output of unit i in terms of heat input or gross electrical output,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent test of unit i in terms of lb/heat input or lb/gross electrical output,

Rmt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAERm = \frac{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Herm_i \times Smm_i \times Cfm_i)\right]_p\right] + \sum_{i=1}^{m}(Ter_i \times Smt_i \times Cft_i)}{\left[\sum_{i=1}^{p}\left[\sum_{i=1}^{n} Smm_i \times Cfm_i\right]_p\right] + \sum_{i=1}^{m} Smt_i \times Cft_i} \quad (Eq.\ 1b)$$

Where:

variables with similar names share the descriptions for Equation 1a,

Smm_i = maximum steam generation in units of pounds from unit i that uses CEMS or sorbent trap monitoring,

Cfm_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring,

Smt_i = maximum steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(2) Weighted 30-day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.2a)$$

Where:

Her_i = hourly emission rate (*e.g.,* lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.2b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Maximum rated heat input or gross electrical output of unit i in terms of lb/heat input or lb/gross electrical output, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.3b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(c) *Separate stack requirements.* For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, you may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (d) through (j) of this section.

(d) For each existing EGU in the averaging group:

(1) The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 180 days after April 16, 2015, or the date on which emissions testing done to support your emissions averaging plan is complete (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; or

(2) The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(e) The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified 180 days after April 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier.

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum normal operating load of each EGU and the results of the initial performance tests. For this demonstration and prior to submitting your emissions averaging plan, if requested, you must conduct required emissions monitoring for 30 days of boiler operation and any required manual performance testing to calculate an initial weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before April 16, 2015. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

(1) You must use Equation 1a in paragraph (b) of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 to this subpart.

(2) If you are not capable of monitoring heat input or gross electrical output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

(g) You must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 day rolling average (90 day rolling average for Hg) basis according to paragraphs (f)(1) through (3) of this section. The first averaging period begins on 30 (or 90 for Hg) days after February 16, 2015 or the date that you begin emissions averaging, whichever is earlier.

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross electrical output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross electrical output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

(h) *CEMS (or sorbent trap monitoring) use.* If an EGU in your emissions averaging group uses CEMS (or a sorbent trap monitor for Hg emissions) to demonstrate compliance, you must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate.

(i) *Emissions testing.* If you use manual emissions testing to demonstrate compliance for one or more EGUs in your emissions averaging group, you must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. You may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate.

(j) *Emissions averaging plan.* You must develop an implementation plan for emissions averaging according to the following procedures and requirements in paragraphs (j)(1) and (2) of this section.

(1) You must include the information contained in paragraphs (j)(1)(i) through (v) of this section in your implementation plan for all the emissions units included in an emissions averaging:

(i) The identification of all existing EGUs in the emissions averaging group, including for each either the applicable HAP emission level or the control technology installed as of 180 days after February 16, 2015, or the date on which you complete the emissions measurements used to support your emissions averaging plan (if the Administrator does not require submission and approval of your emissions averaging plan), or the date that you begin emissions averaging, whichever is earlier; and the date on which you are requesting emissions averaging to commence;

(ii) The process weighting parameter (heat input, gross electrical output, or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission EGU in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple EGUs, you must identify each EGU;

(iv) The means of measurement (*e.g.,* CEMS, sorbent trap monitoring, manual performance test) of filterable PM, SO_2, HF, HCl, individual or total non-Hg HAP metals, or Hg emissions in accordance with the requirements in § 63.10007 and to be used in the emissions averaging calculations; and

(v) A demonstration that emissions averaging can produce compliance with each of the applicable emission limit(s) in accordance with paragraph (b)(1) of this section.

(2) If the Administrator requests you to submit the plan for review and approval, you must submit a complete implementation plan at least 120 days before April 16, 2015. If the Administrator requests you to submit the plan for review and approval, you must receive approval before initiating emissions averaging.

(i) The Administrator shall use following criteria in reviewing and approving or disapproving the plan:

(A) Whether the content of the plan includes all of the information specified in paragraph (h)(1) of this section; and

(B) Whether the plan presents information sufficient to determine that compliance will be achieved and maintained.

(ii) The Administrator shall not approve an emissions averaging implementation plan containing any of the following provisions:

(A) Any averaging between emissions of different pollutants or between units located at different facilities; or

(B) The inclusion of any emissions unit other than an existing unit in the same subcategory.

(k) *Common stack requirements.* For a group of two or more existing affected units, each of which vents through a single common stack, you may average emissions to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraph (l) or (m) of this section.

(l) For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(m) For all other groups of units subject to paragraph (k) of this section, you may elect to conduct manual performance tests according to procedures specified in § 63.10007 in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (*e.g.,* in a different subcategory) or other nonaffected units all vent to the common stack, you must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, you may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. You may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis.

(n) Combination requirements. The common stack of a group of two or more existing EGUs in the same subcategory subject to paragraph (k) of this section may be treated as a single stack for purposes of paragraph (c) of this section and included in an emissions averaging group subject to paragraph (c) of this section.

§ 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, 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:

(1) *Single unit-single stack configurations.* For an affected unit that exhausts to the atmosphere through a single, dedicated stack, you shall either install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere.

(2) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more other affected units, but no non-affected units, you shall either:

(i) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the duct leading to the common stack from each unit; or

(ii) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the common stack.

(3) *Unit(s) utilizing common stack with non-affected unit(s).*

(i) When one or more affected units shares a common stack with one or more non-affected units, you shall either:

(A) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems in the ducts leading to the common stack from each affected unit; or

(B) Install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in this section in the common stack and attribute all of the emissions measured at the common stack to the affected unit(s).

(ii) If you choose the common stack monitoring option:

(A) For each hour in which valid data are obtained for all parameters, you must calculate the pollutant emission rate and

(B) You must assign the calculated pollutant emission rate to each unit that shares the common stack.

(4) *Unit with a main stack and a bypass stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack, or, if it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall install a CEMS only on the main stack and count bypass hours of deviation from the monitoring requirements.

(5) *Unit with a common control device with multiple stack or duct configuration.* If the flue gases from an affected unit, which is configured such that emissions are controlled with a common control device or series of control devices, are discharged to the atmosphere through more than one stack or are fed into a single stack through two or more ducts, you may:

(i) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the multiple stacks;

(ii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in each of the ducts that feed into the stack;

(iii) Install required CEMS, PM CPMS, and sorbent trap monitoring systems in one of the multiple stacks or ducts and monitor the flows and dilution rates in all multiple stacks or ducts in order to determine total exhaust gas flow rate and pollutant mass emissions rate in accordance with the applicable limit; or

(iv) In the case of multiple ducts feeding into a single stack, install CEMS, PM CPMS, and sorbent trap monitoring systems in the single stack as described in paragraph (a)(1) of this section.

(6) *Unit with multiple parallel control devices with multiple stacks.* If the flue gases from an affected unit, which is configured such that emissions are controlled with multiple parallel control devices or multiple series of control devices are discharged to the atmosphere through more than one stack, you shall install the required CEMS, PM CPMS, and sorbent trap monitoring systems described in each of the multiple stacks. You shall calculate hourly flow-weighted average pollutant emission rates for the unit as follows:

(i) Calculate the pollutant emission rate at each stack or duct for each hour in which valid data are obtained for all parameters;

(ii) Multiply each calculated hourly pollutant emission rate at each stack or duct by the corresponding hourly stack gas flow rate at that stack or duct;

(iii) Sum the products determined under paragraph (a)(5)(iii)(B) of this section; and

(iv) Divide the result obtained in paragraph (a)(5)(iii)(C) of this section by the total hourly stack gas flow rate for the unit, summed across all of the stacks or ducts.

(b) If you use an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.,* at the outlet of the EGU, downstream of all emission control devices. You must install, certify, maintain, and operate the CEMS according to part 75 of this chapter. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use part 75 substitute data values.

(c) If you are required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 1 or 2 to this subpart, you must install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to part 75 of this chapter. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations.

(d) If you are required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 1 of 2 to this subpart, you must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, for coal-fired units, you may use appropriate fuel-specific default moisture values from § 75.11(b) of this chapter to estimate the moisture content of the stack gas or you may petition the Administrator under § 75.66 of this chapter for use of a default moisture value for non-coal-fired units. If you install and operate a moisture monitoring system, do not use substitute moisture data in the emissions calculations.

(e) If you use an HCl and/or HF CEMS, you must install, certify, operate, maintain, and quality-assure the data from the monitoring system in accordance with appendix B to this subpart. Calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of appendix B to this subpart).

(f)(1) If you use an SO_2 CEMS, you must install the monitor at the outlet of the EGU, downstream of all emission control devices, and you must certify, operate, and maintain the CEMS according to part 75 of this chapter.

(2) For on-going QA, the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30 boiler operating days.

(4) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

(g) If you use a Hg CEMS or a sorbent trap monitoring system, you must install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with appendix A to this subpart. You must calculate and record a 30-boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate, calculated according to section 6.2 of appendix A to the subpart, is the average of all of the valid hourly Hg emission rates in the preceding 30 boiler operating days. Section 7.1.4.3 of appendix A to this subpart explains how to reduce sorbent trap monitoring system data to an hourly basis.

(h) If you use a PM CPMS to demonstrate continuous compliance with an operating limit, 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.

(1) Install, calibrate, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.10000(d), and meet the requirements in paragraphs (h)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of the exhaust gas or representative sample. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration, or other raw data signal.

(ii) The PM CPMS must have a cycle time (*i.e.*, period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable, at a minimum, of detecting and responding to particulate matter concentrations of 0.5 mg/acm.

(2) For a new unit, complete the initial PM CPMS performance evaluation no later than October 13, 2012 or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than October 13, 2015.

(3) Collect PM CPMS hourly average output data for all boiler operating hours except as indicated in paragraph (h)(5) of this section. Express the PM CPMS output as milliamps, PM concentration, or other raw data signal value.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CPMS output collected during all nonexempt boiler operating hours data (*e.g.*, milliamps, PM concentration, raw data signal).

(5) You must collect data using the PM CPMS at all times the process unit is operating and at the intervals specified in paragraph (h)(1)(ii) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), and any scheduled maintenance as defined in your site-specific monitoring plan.

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

(i) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions are not used in calculations (report any such periods in your annual deviation report);

(ii) 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 are not used in calculations (report emissions or operating levels and report any such periods in your annual deviation report);

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

(7) You must record and make available upon request results of PM CPMS system performance audits, as well as the dates and duration of periods from when the PM CPMS is out of control until completion of the corrective actions necessary to return the PM CPMS to operation consistent with your site-specific monitoring plan.

(i) If you choose to comply with the PM filterable emissions limit in lieu of metal HAP limits, you may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of this section. 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 to this subpart.

(1) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A–3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ± 14°C (320° ± 25°F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (*e.g.*, lb/MMBtu, lb/MWh).

(2) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(i) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(ii) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(3) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(4) Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.

(5) You must collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

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

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(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 control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

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

(ii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(j) You may choose to comply with the metal HAP emissions limits using CEMS 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 CEMS, 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 CEMS and record the output of the HAP metals CEMS as specified in paragraphs (j)(1) through (5) of this section.

(1)(i) Install and certify your HAP metals CEMS according to the procedures and requirements in you approved site specific test plan as required in § 63.7(e). The reportable measurement output from the HAP metals CEMS 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 CEMS 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 CEMS 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 CEMS output data collected during all nonexempt boiler operating hours data.

(4) You must collect data using the HAP metals CEMS at all times the process unit is operating and at the intervals specified in paragraph (a) of this section, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(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 monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(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 control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

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

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

(k) If you demonstrate compliance with the HCl and HF emission limits for a liquid oil-fired EGU by conducting quarterly testing, you must also develop a site-specific monitoring plan as provided for in § 63.10000(c)(2)(iii) and Table 7 to this subpart.

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

(a) You must demonstrate initial compliance with each emissions limit that applies to you by conducting performance testing.

(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, or if, for a liquid oil-fired 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 Table 4 to this subpart, § 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.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.*, Hg or HCl) directly, the first 30-boiler operating day rolling average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For a unit that uses a CEMS to measure SO_2 or PM emissions for initial compliance, the first 30 boiler operating day average emission rate obtained with certified CEMS after the applicable date in § 63.9984 (or, if applicable, prior to that date, as described in § 63.10005(b)(2)), expressed in units of the standard, is the initial performance test. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or filterable PM emission limit in Table 1 or 2 to this subpart.

(d) For candidate LEE units, use the results of the performance testing described in § 63.10005(h) to determine initial compliance with the applicable emission limit(s) in Table 1 or 2 to this subpart and to determine whether the unit qualifies for LEE status.

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, according to § 63.10030(e).

(f)(1) You must determine the fuel whose combustion produces the least uncontrolled emissions, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown.

(2) Your cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account.

(g) You must follow the startup or shutdown requirements given in Table 3 for each coal-fired, liquid oil-fired, and solid oil-derived fuel-fired EGU.

Continuous Compliance Requirements

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

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10000(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. You are required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during EGU startup or shutdown or monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

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

(a) You must demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you, according to the monitoring specified in Tables 6 and 7 to this subpart and paragraphs (b) through (g) of this section.

(b) Except as otherwise provided in § 63.10020(c), if you use a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg emissions, you must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (*e.g.,* flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 to determine the 30-boiler operating day rolling average.

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \quad (Eq.\ 8)$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30 boiler operating days.

(c) If you use a PM CPMS data 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.

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

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.

(d) If you use quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 1 or 2 to this subpart, you

(1) May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year.

(2) Must conduct the performance test as defined in Table 5 to this subpart and calculate the results of the testing in units of the applicable emissions standard; and

(3) Must conduct site-specific monitoring for a liquid oil-fired unit to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020(a).

(e) If you must conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section, perform the first tune-up as part of your initial compliance demonstration. Notwithstanding this requirement, you may delay the first burner inspection until the next scheduled unit outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

(1) As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows:

(i) Burner or combustion control component parts needing replacement that affect the ability to optimize NO_X and CO must be installed within 3 calendar months after the burner inspection,

(ii) Burner or combustion control component parts that do not affect the ability to optimize NO_X and CO may be installed on a schedule determined by the operator;

(2) As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type;

(3) As applicable, observe the damper operations as a function of mill and/or cyclone loadings, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors;

(4) As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors;

(5) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary;

(6) Optimize combustion to minimize generation of CO and NO_X. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_X optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles;

(7) While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_X in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). You may use portable CO, NO_X and O_2 monitors for this measurement. EGU's employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system;

(8) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (e)(1) through (e)(9) of this section including:

(i) The concentrations of CO and NO_X in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems;

(ii) A description of any corrective actions taken as a part of the combustion adjustment; and

(iii) The type(s) and amount(s) of fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period; and

(9) Report the dates of the initial and subsequent tune-ups as follows:

(i) If the first required tune-up is performed as part of the initial compliance demonstration, report the date of the tune-up in hard copy (as specified in § 63.10030) and electronically (as specified in § 63.10031). Report the date of each subsequent tune-up electronically (as specified in § 63.10031).

(ii) If the first tune-up is not conducted as part of the initial compliance demonstration, but is postponed until the next unit outage, report the date of that tune-up and all subsequent tune-ups electronically, in accordance with § 63.10031.

(f) You must submit the reports required under § 63.10031 and, if applicable, the reports required under appendices A and B to this subpart. The electronic reports required by appendices A and B to this subpart must be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in § 63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under § 63.10031.

(g) You must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031.

(h) You must keep records as specified in § 63.10032 during periods of startup and shutdown.

(i) You must provide reports as specified in § 63.10031 concerning activities and periods of startup and shutdown.

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

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (3) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);

(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;

(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.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

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

(a) During the initial performance test or any such subsequent performance test that demonstrates compliance with the filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 1 or 2, record all hourly average output values (*e.g.*, milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (*e.g.*, nine 1-hour average PM CPMS output values for three 3-hour test runs).

(b) Determine your operating limit as the highest 1-hour average PM CPMS output value recorded during the performance test. You must verify an existing or establish a new operating limit after each repeated performance test.

(c) You must operate and maintain your process and control equipment such that the 30 operating day average PM CPMS output does not exceed the operating limit determined in paragraphs (a) and (b) of this section.

Notification, Reports, and Records

§ 63.10030 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) When you are required to conduct an initial compliance demonstration as specified in § 63.10011(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (7), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests and fuel analyses and calculations conducted to demonstrate initial compliance including all established operating limits.

(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); CEMS; or a sorbent trap monitoring system.

(4) Identification of whether you plan to demonstrate compliance by emissions averaging.

(5) A signed certification that you have met all applicable emission limits and work practice standards.

(6) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation in the Notification of Compliance Status report.

(7) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following:

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(i), the date of the last three stack tests, a comparison of the emission level you achieved in the last three stack tests to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

(ii) Certifications of compliance, as applicable, and must be signed by a responsible official stating:

(A) ''This EGU complies with the requirements in § 63.10021(a) to demonstrate continuous compliance.'' and

(B) ''No secondary materials that are solid waste were combusted in any affected unit.''

§ 63.10031 What reports must I submit and when?

(a) You must submit each report in Table 8 to this subpart that applies to you. If you are required to (or elect to) continuously monitor Hg and/or HCl and/or HF emissions, you must also submit the electronic reports required under appendix A and/or appendix B to the subpart, at the specified frequency.

(b) Unless the Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 8 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.9984 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in § 63.9984.

(2) The first compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.9984.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (4) of this section.

(1) The information required by the summary report located in 63.10(e)(3)(vi).

(2) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(3) Indicate whether you burned new types of fuel during the reporting period. If you did burn new types of fuel you must include the date of the performance test where that fuel was in use.

(4) Include the date of the most recent tune-up for each unit subject to the requirement to conduct a performance tune-up according to § 63.10021(e). Include the date of the most recent burner inspection if it was not done annually and was delayed until the next scheduled unit shutdown.

(d) For each excess emissions occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in § 63.10(e)(3)(v) in the compliance report specified in section (c).

(e) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(f) As of January 1, 2012, and within 60 days after the date of completing each performance test, you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(1) Within 60 days after the date of completing each CEMS (SO_2, PM, HCl, HF, and Hg) performance evaluation test, as defined in § 63.2 and required by this subpart, you must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). The RATA data shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only RATA data compounds listed on the ERT Web site are subject to this requirement. Owners or operators who claim that some of the information being submitted for RATAs is confidential business information (CBI) shall submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. The compact disk or other commonly used electronic storage media shall be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, owners or operators shall also submit these RATAs to the delegated authority in the format specified by the delegated authority. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in § 63.2 and as required in this chapter.

(2) For a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st, you must submit quarterly reports to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS.

(3) Reports for an SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, an HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in Appendices A and B to this subpart and § 63.10021(f).

(4) Submit the compliance reports required under paragraphs (c) and (d) of this section and the notification of compliance status required under § 63.10030(e) to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with EPA's reporting form output format.

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1), (2), and (3) of this section in paper format.

(g) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

§ 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 emissions, you must also keep the records required under appendix A and/or appendix B to this subpart.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in § 63.10(b)(2)(viii).

(b) For each CEMS and CPMS, you must keep records according to paragraphs (b)(1) through (4) of this section.

(1) Records described in § 63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(3) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 7 to this subpart including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each EGU subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (3) of this section.

(1) You must keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), you must keep a record which documents how the fuel satisfies the requirements of the petition process.

(3) For an EGU that qualifies as an LEE under § 63.10005(h), you must keep annual records that document that your emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year.

(e) If you elect to average emissions consistent with § 63.10009, you must additionally keep a copy of the emissions averaging implementation plan required in § 63.10009(g), all calculations required under § 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.10022.

(f) You must keep records of the occurrence and duration of each startup and/or shutdown.

(g) You must keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(h) You must keep records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(i) You must keep records of the type(s) and amount(s) of fuel used during each startup or shutdown.

(j) If you elect to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, you must keep records of the type(s) and amount(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met.

§ 63.10033 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.10040 What parts of the General Provisions apply to me?

Table 9 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.10041 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (4) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency; moreover, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate, with respect to any failure by any person to comply with any provision of this subpart.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.9991(a) and (b) under § 63.6(g).

(2) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, approval of minor and intermediate changes to monitoring performance specifications/procedures in Table 5 where the monitoring serves as the performance test method (see definition of ''test method'' in § 63.2.

(3) Approval of major changes to monitoring under § 63.8(f) and as defined in § 63.90.

(4) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.10042 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

Boiler operating day means a 24-hour period between midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for the fuel to be combusted the entire 24-hour period.

Capacity factor for a liquid oil-fired EGU means the total annual heat input from oil divided by the product of maximum hourly heat input for the EGU, regardless of fuel, multiplied by 8,760 hours.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent-refined coal, coal-oil mixtures, and coal-water mixtures, are considered ''coal'' for the purposes of this subpart.

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that burns coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Coal refuse means any by-product of coal mining, physical coal cleaning, and coal preparation operations (*e.g.,* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Cogeneration means a steam-generating unit that simultaneously produces both electrical and useful thermal (or mechanical) energy from the same primary energy source.

Cogeneration unit means a stationary, fossil fuel-fired EGU meeting the definition of ''fossil fuel-fired'' or stationary, integrated gasification combined cycle:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combined-cycle gas stationary combustion turbine means a stationary combustion turbine system where heat from the turbine exhaust gases is recovered by a waste heat boiler.

Common stack means the exhaust of emissions from two or more affected units through a single flue.

Continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located in the continental United States.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, work practice standard, or monitoring requirement; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM Method D396–10, ''Standard Specification for Fuel Oils'' (incorporated by reference, see § 63.14).

Dry flue gas desulfurization technology, or *dry FGD,* or *spray dryer absorber* (*SDA*), or *spray dryer,* or *dry scrubber* means an add-on air pollution control system located downstream of the steam generating unit that injects a dry alkaline sorbent (dry sorbent injection) or sprays an alkaline sorbent slurry (spray dryer) to react with and neutralize acid gases such as SO_2 and HCl in the exhaust stream forming a dry powder material. Alkaline sorbent injection systems in fluidized bed combustors (FBC) or circulating fluidized bed (CFB) boilers are included in this definition.

Dry sorbent injection (DSI) means an add-on air pollution control system in which sorbent (*e.g.*, conventional activated carbon, brominated activated carbon, Trona, hydrated lime, sodium carbonate, etc.) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases (such as SO_2 and HCl) or Hg in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

Electric Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included) for the purpose of powering a generator to produce electricity or electricity and other thermal energy.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Emission limitation means any emissions limit, work practice standard, or operating limit.

Excess emissions means, with respect to this subpart, results of any required measurements outside the applicable range (*e.g.,* emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60, 61, and 63; requirements within any applicable state implementation plan; and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Flue gas desulfurization system means any add-on air pollution control system located downstream of the steam generating unit whose purpose or effect is to remove at least 50 percent of the SO_2 in the exhaust gas stream.

Fossil fuel means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.*, coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after the applicable compliance date.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Fluidized bed boiler, or *fluidized bed combustor,* or *circulating fluidized boiler,* or *CFB* means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles which are maintained in a mobile suspension by the upward flow of air and combustion products.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, solid oil-derived gas, refinery gas, and biogas.

Generator means a device that produces electricity.

Gross output means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the work performed by the stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical output, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls), or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.,* steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in an EGU (synthetic gas for an IGCC) and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, etc.

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

ISO conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14).

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

Liquid fuel includes, but is not limited to, distillate oil and residual oil.

Monitoring system malfunction or out of control period means any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Net-electric output means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

Non-continental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Non-continental liquid oil-fired subcategory means any oil-fired electric utility steam generating unit that burns liquid oil and is located outside the continental United States.

Non-mercury (Hg) HAP metals means Antimony (Sb), Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), Nickel (Ni), and Selenium (Se). *Oil* means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, solid oil-derived fuel (*e.g.,* petroleum coke) and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year.

Particulate matter or *PM* means any finely divided solid material as measured by the test methods specified under this subpart, or an alternative method.

Pulverized coal (PC) boiler means an EGU in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the EGU where it is fired in suspension.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by ASTM Method D396–10, ''Standard Specification for Fuel Oils'' (incorporated by reference, see § 63.14).

Responsible official means responsible official as defined in 40 CFR 70.2.

Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none 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), or at the point of no fuel being fired in the boiler, whichever is earlier. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler.

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).

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. Stationary combustion turbines do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with integrated gasification combined cycle gas turbines; nuclear steam generators are not included).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit undergrate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. There are two general types of stokers: underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388–05, ‘‘Standard Classification of Coals by Rank’’ (incorporated by reference, see § 63.14).

Unit designed for coal > 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the ‘‘unit designed for low rank virgin coal’’ subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning nonagglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed to burn solid oil-derived fuel subcategory means any oil-fired EGU that burns solid oil-derived fuel.

Voluntary consensus standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. states, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within an EPA rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-VCS methods.

Wet flue gas desulfurization technology, or *wet FGD, or wet scrubber* means any add-on air pollution control device that is located downstream of the steam generating unit that mixes an aqueous stream or slurry with the exhaust gases from an EGU to control emissions of PM and/or to absorb and neutralize acid gases, such as SO_2 and HCl.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to CAA section 112(h).

Tables to Subpart UUUUU of Part 63

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 . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	7.0E–3 lb/MWh[1]	Collect a minimum 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/GW.	
	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–3 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HC1)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[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)	2.0E–4 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	7.0E–3 lb/MWh[1]	Collect a minimum 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.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[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 . . .
	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–3 lb/GWh.	
	Manganese (Mn)	4.0E–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[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)	4.0E–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 of 1 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, collect a minimum of 120 liters per run. For ASTM D6348–03[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).	7.0E–2 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.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[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 . . .
	Mercury (Hg)	1.0E–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)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[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[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 Total HAP metals	OR 7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	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)	4.1E–0 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[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[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	2.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	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.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs—Continued

[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 . . .
	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[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)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross electric 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 and SO_2 CEMS installed.

[4] Duct burners on syngas; gross electric output.

[5] Duct burners on natural gas; gross electric output

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
1. Coal-fired unit not low rank virgin coal.	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	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals		
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–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, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320, 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 10 days maximum 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).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[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
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–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, collect a minimum of 120 liters per run. For ASTM D6348–03[3] or Method 320, 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)	4.0E0 lb/TBtu or 4.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum 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/MWh2.	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	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.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/MMBtu or 1.8E0 lb/MWh.	
	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[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 10 days maximum 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/MWh2.	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals	OR	Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

[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
	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[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[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/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	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.
	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[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[3] or Method 320, sample for a minimum of 2 hours.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

[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
6. Solid oil-derived fuel-fired unit ..	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh2.	Collect a minimum of 1 dscm per run.
	OR	OR	
	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	
	Individual HAP metals	....	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–2 lb/TBtu or 6.0E–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 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[3] or Method 320, sample for a minimum of 1 hour.
	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 10 days maximum 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 two.

[2] Gross electric 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.

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, or solid oil-derived fuel-fired EGU during startup.	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, either natural gas or distillate oil or a combination of clean fuels 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 definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS—Continued

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

If your EGU is . . .	You must meet the following . . .
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. Shutdown means the cessation of operation of a boiler for any purpose. Shutdown begins either when none 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) or at the point of no fuel being fired in the boiler. Shutdown ends when there is both no electricity being generated and no fuel being fired in the boiler. During shutdown, you must operate all applicable control technologies while firing coal, residual oil, or solid oil-derived fuel. You must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in this subpart. You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

TABLE 4 TO SUBPART UUUUU OF PART 63—OPERATING LIMITS FOR EGUS

[As stated in § 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test 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).

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]]

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	Method 5 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 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 electrical output data (see § 63.10007(e)).
	OR PM CEMS	OR a. Install, certify, operate, and maintain the PM CEMS.	Performance Specification 11 at Appendix B to part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		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 electrical 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.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

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

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] . . .
		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 each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	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 report the front half and back half results separately.
		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 electrical 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 emissions concentrations.	Method 26 or Method 26A at Appendix A–8 to part 60 of this chapter or Method 320 at Appendix A to part 63 of this chapter or ASTM 6348–03[3] with (1) additional quality assurance measures in footnote[4] and (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 electrical 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 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 electrical 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.

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

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

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] . . .
		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 electrical output data (see § 63.10007(e)).
	OR	OR	
		Hg CEMS .... a. Install, certify, operate, and maintain the CEMS.	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		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 emissions rates.	Section 6 of Appendix A to this subpart.
	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 electrical 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 22.0 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 electrical output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and § 63.10021(h).

[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.

[4] When using ASTM D6348–03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (2) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be $70\% \geq R \leq 130\%$; and (4) 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:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \, x\, 100$$

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

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 . . .
Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, individual HAP metals.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(g)(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 three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

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, SO2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30-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 boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit	Calculating the arithmetic 30-boiler operating day rolling 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 boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring for liquid oil-fired units 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 units to measure compliance with one or more applicable emissions limit in Table 1 or 2.	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.

TABLE 8 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

[As stated in § 63.10031, you must comply with the following requirements for reports]

You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.10031(c)(1) through (4); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e).	Semiannually according to the requirements in § 63.10031(b).

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (h)(2)–(h)(9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1), (c), (d)(1)–(2), (e), and (f)	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii)–(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3), and (d)(3)–(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

1. General Provisions

1.1 *Applicability.* These monitoring provisions apply to the measurement of total vapor phase mercury (Hg) in emissions from electric utility steam generating units, using either a mercury continuous emission monitoring system (Hg CEMS) or a sorbent trap monitoring system. The Hg CEMS or sorbent trap monitoring system must be capable of measuring the total vapor phase mercury in units of the applicable emissions standard (*e.g.,* lb/TBtu or lb/GWh), regardless of speciation.

1.2 *Initial Certification and Recertification Procedures.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall comply with the initial certification and recertification procedures in section 4 of this appendix.

1.3 *Quality Assurance and Quality Control Requirements.* The owner or operator of an affected unit that uses a Hg CEMS or a sorbent trap monitoring system together with other necessary monitoring components to account for Hg emissions in units of the applicable emissions standard shall meet the applicable quality assurance requirements in section 5 of this appendix.

1.4 *Missing Data Procedures.* The owner or operator of an affected unit is not required to substitute for missing data from Hg CEMS or sorbent trap monitoring systems. Any process operating hour for which quality-assured Hg concentration data are not obtained is counted as an hour of monitoring system downtime.

2. Monitoring of Hg Emissions

2.1 *Monitoring System Installation Requirements.* Flue gases from the affected units under this subpart vent to the atmosphere through a variety of exhaust configurations including single stacks, common stack configurations, and multiple stack configurations. For each of these configurations, § 63.10010(a) specifies the appropriate location(s) at which to install continuous monitoring systems (CMS). These CMS installation provisions apply to the Hg CEMS, sorbent trap monitoring systems, and other continuous monitoring systems that provide data for the Hg emissions calculations in section 6.2 of this appendix.

2.2 *Primary and Backup Monitoring Systems.* In the electronic monitoring plan described in section 7.1.1.2.1 of this appendix, you must designate a primary Hg CEMS or sorbent trap monitoring system. The primary system must be used to report hourly Hg concentration values when the system is able to provide quality-assured data, *i.e.,* when the system is ''in control''. However, to increase data availability in the event of a primary monitoring system outage, you may install, operate, maintain, and calibrate backup monitoring systems, as follows:

2.2.1 *Redundant Backup Systems.* A redundant backup monitoring system may be either a separate Hg CEMS with its own probe, sample interface, and analyzer, or a separate sorbent trap monitoring system. A redundant backup system is one that is permanently installed at the unit or stack location, and is kept on ''hot standby'' in case the primary monitoring system is unable to provide quality-assured data. A redundant backup system must be represented as a unique monitoring system in the electronic monitoring plan. Each redundant backup monitoring system must be certified according to the applicable provisions in section 4 of this appendix and must meet the applicable on-going QA requirements in section 5 of this appendix.

2.2.2 *Non-redundant Backup Monitoring Systems.* A non-redundant backup monitoring system is a separate Hg CEMS or sorbent trap system that has been certified at a particular unit or stack location, but is not permanently installed at that location. Rather, the system is kept on ''cold standby'' and may be reinstalled in the event of a primary monitoring system outage. A non-redundant backup monitoring system must be represented as a unique monitoring system in the electronic monitoring plan. Non-redundant backup Hg CEMS must complete the same certification tests as the primary monitoring system, with one exception. The 7-day calibration error test is not required for a non-redundant backup Hg CEMS. Except as otherwise provided in section 2.2.4.5 of this appendix, a non-redundant backup monitoring system may only be used for 720 hours per year at a particular unit or stack location.

2.2.3 *Temporary Like-kind Replacement Analyzers.* When a primary Hg analyzer needs repair or maintenance, you may temporarily install a like-kind replacement analyzer, to minimize data loss. Except as otherwise provided in section 2.2.4.5 of this appendix, a temporary like-kind replacement analyzer may only be used for 720 hours per year at a particular unit or stack location. The analyzer must be represented as a component of the primary Hg CEMS, and must be assigned a 3-character component ID number, beginning with the prefix ''LK''.

2.2.4 *Quality Assurance Requirements for Non-redundant Backup Monitoring Systems and Temporary Like-kind Replacement Analyzers.* To quality-assure the data from non-redundant backup Hg monitoring systems and temporary like-kind replacement Hg analyzers, the following provisions apply:

2.2.4.1 When a certified non-redundant backup sorbent trap monitoring system is brought into service, you must follow the procedures for routine day-to-day operation of the system, in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

2.2.4.2 When a certified non-redundant backup Hg CEMS or a temporary like-kind replacement Hg analyzer is brought into service, a calibration error test and a linearity check must be performed and passed. A single point system integrity check is also required, unless a NIST-traceable source of oxidized Hg was used for the calibration error test.

2.2.4.3 Each non-redundant backup Hg CEMS or temporary like-kind replacement Hg analyzer shall comply with all required daily, weekly, and quarterly quality-assurance test requirements in section 5 of this appendix, for as long as the system or analyzer remains in service.

2.2.4.4 For the routine, on-going quality-assurance of a non-redundant backup Hg monitoring system, a relative accuracy test audit (RATA) must be performed and passed at least once every 8 calendar quarters at the unit or stack location(s) where the system will be used.

2.2.4.5 To use a non-redundant backup Hg monitoring system or a temporary like-kind replacement analyzer for more than 720 hours per year at a particular unit or stack location, a RATA must first be performed and passed at that location.

3. Mercury Emissions Measurement Methods

The following definitions, equipment specifications, procedures, and performance criteria are applicable to the measurement of vapor-phase Hg emissions from electric utility steam generating units, under relatively low-dust conditions (i.e., sampling in the stack or duct after all pollution control devices). The analyte measured by these procedures and specifications is total vapor-phase Hg in the flue gas, which represents the sum of elemental Hg ($Hg^{0,}$ CAS Number 7439–97–6) and oxidized forms of Hg.

3.1 *Definitions.*

3.1.1 *Mercury Continuous Emission Monitoring System or Hg CEMS* means all of the equipment used to continuously determine the total vapor phase Hg concentration. The measurement system may include the following major subsystems: sample acquisition, Hg^{+2} to Hg^{0} converter, sample transport, sample conditioning, flow control/gas manifold, gas analyzer, and data acquisition and handling system (DAHS). Hg CEMS may be nominally real-time or time-integrated, batch sampling systems that sample the gas on an intermittent basis and concentrate on a collection medium before intermittent analysis and reporting.

3.1.2 *Sorbent Trap Monitoring System* means the equipment required to monitor Hg emissions continuously by using paired sorbent traps containing iodated charcoal (IC) or other suitable sorbent medium. The monitoring system consists of a probe, paired sorbent traps, an umbilical line, moisture removal components, an airtight sample pump, a gas flow meter, and an automated data acquisition and handling system. The system samples the stack gas at a constant proportional rate relative to the stack gas volumetric flow rate. The sampling is a batch process. The average Hg concentration in the stack gas for the sampling period is determined, in units of micrograms per dry standard cubic meter (μg/dscm), based on the sample volume measured by the gas flow meter and the mass of Hg collected in the sorbent traps.

3.1.3 *NIST* means the National Institute of Standards and Technology, located in Gaithersburg, Maryland.

3.1.4 *NIST–Traceable Elemental Hg Standards* means either: compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the ‘‘EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards’’; or calibration gases having known concentrations of elemental Hg, produced by a generator that meets the performance requirements of the ‘‘EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators’’ or an interim version of that protocol.

3.1.5 *NIST–Traceable Source of Oxidized Hg* means a generator that is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that meets the performance requirements of the ‘‘EPA Traceability Protocol for Qualification and Certification of Mercuric Chloride Gas Generators’’ or an interim version of that protocol.

3.1.6 *Calibration Gas* means a NIST-traceable gas standard containing a known concentration of elemental or oxidized Hg that is produced and certified in accordance with an EPA traceability protocol.

3.1.7 *Span Value* means a conservatively high estimate of the Hg concentrations to be measured by a CEMS. The span value of a Hg CEMS should be set to approximately twice the concentration corresponding to the emission standard, rounded off as appropriate (see section 3.2.1.4.2 of this appendix).

3.1.8 *Zero-Level Gas* means calibration gas containing a Hg concentration that is below the level detectable by the Hg gas analyzer in use.

3.1.9 *Low-Level Gas* means calibration gas with a concentration that is 20 to 30 percent of the span value.

3.1.10 *Mid-Level Gas* means calibration gas with a concentration that is 50 to 60 percent of the span value.

3.1.11 *High-Level Gas* means calibration gas with a concentration that is 80 to 100 percent of the span value.

3.1.12 *Calibration Error Test* means a test designed to assess the ability of a Hg CEMS to measure the concentrations of calibration gases accurately. A zero-level gas and an upscale gas are required for this test. For the upscale gas, either a mid-level gas or a high-level gas may be used, and the gas may either be an elemental or oxidized Hg standard.

3.1.13 *Linearity Check* means a test designed to determine whether the response of a Hg analyzer is linear across its measurement range. Three elemental Hg calibration gas standards (i.e., low, mid, and high-level gases) are required for this test.

3.1.14 *System Integrity Check* means a test designed to assess the transport and measurement of oxidized Hg by a Hg CEMS. Oxidized Hg standards are used for this test. For a three-level system integrity check, low, mid, and high-level calibration gases are required. For a single-level check, either a mid-level gas or a high-level gas may be used.

3.1.15 *Cycle Time Test* means a test designed to measure the amount of time it takes for a Hg CEMS, while operating normally, to respond to a known step change in gas concentration. For this test, a zero gas and a high-level gas are required. The high-level gas may be either an elemental or an oxidized Hg standard.

3.1.16 *Relative Accuracy Test Audit* or *RATA* means a series of nine or more test runs, directly comparing readings from a Hg CEMS or sorbent trap monitoring system to measurements made with a reference stack test method. The relative accuracy (RA) of the monitoring system is expressed as the absolute mean difference between the monitoring system and reference method measurements plus the absolute value of the 2.5 percent error confidence coefficient, divided by the mean value of the reference method measurements.

3.1.17 *Unit Operating Hour* means a clock hour in which a unit combusts any fuel, either for part of the hour or for the entire hour.

3.1.18 *Stack Operating Hour* means a clock hour in which gases flow through a particular monitored stack or duct (either for part of the hour or for the entire hour), while the associated unit(s) are combusting fuel.

3.1.19 *Operating Day* means a calendar day in which a source combusts any fuel.

3.1.20 Quality Assurance *(QA) Operating Quarter* means a calendar quarter in which there are at least 168 unit or stack operating hours (as defined in this section).

3.1.21 *Grace Period* means a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

3.2 *Continuous Monitoring Methods.*

3.2.1 *Hg CEMS.* A typical Hg CEMS is shown in Figure A–1. The CEMS in Figure A–1 is a dilution extractive system, which measures Hg concentration on a wet basis, and is the most commonly-used type of Hg CEMS. Other system designs may be used, provided that the CEMS meets the performance specifications in section 4.1.1 of this appendix.

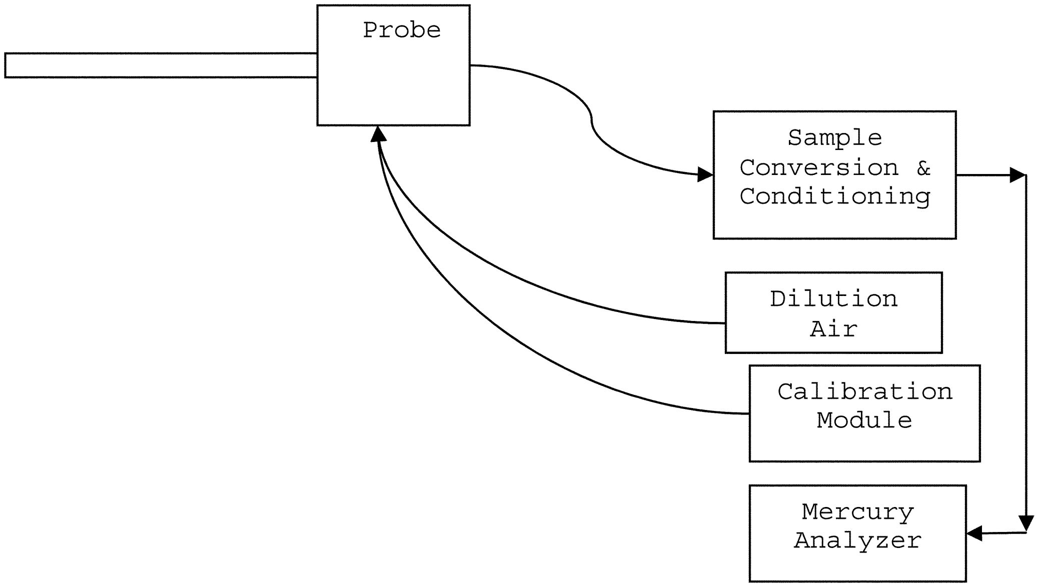

FIGURE A-1. TYPICAL MERCURY CEMS

3.2.1.1 *Equipment Specifications.*

3.2.1.1.1 *Materials of Construction.* All wetted sampling system components, including probe components prior to the point at which the calibration gas is introduced, must be chemically inert to all Hg species. Materials such as perfluoroalkoxy (PFA) Teflon™, quartz, and treated stainless steel (SS) are examples of such materials.

3.2.1.1.2 *Temperature Considerations.* All system components prior to the Hg^{+2} to Hg^0 converter must be maintained at a sample temperature above the acid gas dew point.

3.2.1.1.3 *Measurement System Components.*

3.2.1.1.3.1 *Sample Probe.* The probe must be made of the appropriate materials as noted in paragraph 3.2.1.1.1 of this section, heated when necessary, as described in paragraph 3.2.1.1.3.4 of this section, and configured with ports for introduction of calibration gases.

3.2.1.1.3.2 *Filter or Other Particulate Removal Device.* The filter or other particulate removal device is part of the measurement system, must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section, and must be included in all system tests.

3.2.1.1.3.3 *Sample Line.* The sample line that connects the probe to the converter, conditioning system, and analyzer must be made of appropriate materials, as noted in paragraph 3.2.1.1.1 of this section.

3.2.1.1.3.4 *Conditioning Equipment.* For wet basis systems, such as the one shown in Figure A–1, the sample must be kept above its dew point either by: heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer); or diluting the sample prior to analysis using a dilution probe system. The components required for these operations are considered to be conditioning equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas, and any equipment needed to heat the probe or sample line to avoid condensation prior to the moisture removal component is also required.

3.2.1.1.3.5 *Sampling Pump.* A pump is needed to push or pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. If a mechanical sample pump is used and its surfaces are in contact with the sample gas prior to detection, the pump must be leak free and must be constructed of a material that is non-reactive to the gas being sampled (see paragraph 3.2.1.1.1 of this section). For dilution-type measurement systems, such as the system shown in Figure A–1, an ejector pump (eductor) may be used to create a sufficient vacuum that sample gas will be drawn through a critical orifice at a constant rate. The ejector pump must be constructed of any material that is non-reactive to the gas being sampled.

3.2.1.1.3.6 *Calibration Gas System(s).* Design and equip each Hg CEMS to permit the introduction of known concentrations of elemental Hg and $HgCl_2$ separately, at a point preceding the sample extraction filtration system, such that the entire measurement system can be checked. The calibration gas system(s) must be designed so that the flow rate exceeds the sampling system flow requirements and that the gas is delivered to the CEMS at atmospheric pressure.

3.2.1.1.3.7 *Sample Gas Delivery.* The sample line may feed directly to either a converter, a by-pass valve (for Hg speciating systems), or a sample manifold. All valve and/or manifold components must be made of material that is non-reactive to the gas sampled and the calibration gas, and must be configured to safely discharge any excess gas.

3.2.1.1.3.8 *Hg Analyzer.* An instrument is required that continuously measures the total vapor phase Hg concentration in the gas stream. The analyzer may also be capable of measuring elemental and oxidized Hg separately.

3.2.1.1.3.9 *Data Recorder.* A recorder, such as a computerized data acquisition and handling system (DAHS), digital recorder, or data logger, is required for recording measurement data.

3.2.1.2 *Reagents and Standards.*

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this section) shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (*e.g.,* NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

3.2.1.2.2 *Required Calibration Gas Concentrations.*

3.2.1.2.2.1 *Zero-Level Gas.* A zero-level calibration gas with a Hg concentration below the level detectable by the Hg analyzer is required for calibration error tests and cycle time tests of the CEMS.

3.2.1.2.2.2 *Low-Level Gas.* A low-level calibration gas with a Hg concentration of 20 to 30 percent of the span value is required for linearity checks and 3-level system integrity checks of the CEMS. Elemental Hg standards are required for the linearity checks and oxidized Hg standards are required for the system integrity checks.

3.2.1.2.2.3 *Mid-Level Gas.* A mid-level calibration gas with a Hg concentration of 50 to 60 percent of the span value is required for linearity checks and for 3-level system integrity checks of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error tests.

3.2.1.2.2.4 *High-Level Gas.* A high-level calibration gas with a Hg concentration of 80 to 100 percent of the span value is required for linearity checks, 3-level system integrity checks, and cycle time tests of the CEMS, and is optional for calibration error tests and single-level system integrity checks. Elemental Hg standards are required for the linearity checks, oxidized Hg standards are required for the system integrity checks, and either elemental or oxidized Hg standards may be used for the calibration error and cycle time tests.

3.2.1.3 *Installation and Measurement Location.* For the Hg CEMS and any additional monitoring system(s) needed to convert Hg concentrations to the desired units of measure (i.e., a flow monitor, CO_2 or O_2 monitor, and/or moisture monitor, as applicable), install each monitoring system at a location: that is consistent with 63.10010(a); that represents the emissions exiting to the atmosphere; and where it is likely that the CEMS can pass the relative accuracy test.

3.2.1.4 *Monitor Span and Range Requirements.* Determine the appropriate span and range value(s) for the Hg CEMS as described in paragraphs 3.2.1.4.1 through 3.2.1.4.3 of this section.

3.2.1.4.1 *Maximum Potential Concentration.* There are three options for determining the maximum potential Hg concentration (MPC). Option 1 applies to coal combustion. You may use a default value of 10 μg/scm for all coal ranks (including coal refuse) except for lignite; for lignite, use 16 μg/scm. If different coals are blended as part of normal operation, use the highest MPC for any fuel in the blend. Option 2 is to base the MPC on the results of site-specific Hg emission testing. This option may be used only if the unit does not have add-on Hg emission controls or a flue gas desulfurization system, or if testing is performed upstream of all emission control devices. If Option 2 is selected, perform at least three test runs at the normal operating load, and the highest Hg concentration obtained in any of the tests shall be the MPC. Option 3 is to use fuel sampling and analysis to estimate the MPC. To make this estimate, use the average Hg content (*i.e.,* the weight percentage) from at least three representative fuel samples, together with other available information, including, but not limited to the maximum fuel feed rate, the heating value of the fuel, and an appropriate F-factor. Assume that all of the Hg in the fuel is emitted to the atmosphere as vapor-phase Hg.

3.2.1.4.2 *Span Value.* To determine the span value of the Hg CEMS, multiply the Hg concentration corresponding to the applicable emissions standard by two. If the result of this calculation is an exact multiple of 10 μg/scm, use the result as the span value. Otherwise, round off the result to either: the next highest integer; the next highest multiple of 5 μg/scm; or the next highest multiple of 10 μg/scm.

3.2.1.4.3 *Analyzer Range.* The Hg analyzer must be capable of reading Hg concentration as high as the MPC.

3.2.2 *Sorbent Trap Monitoring System.* A sorbent trap monitoring system (as defined in paragraph 3.1.2 of this section) may be used as an alternative to a Hg CEMS. If this option is selected, the monitoring system shall be installed, maintained, and operated in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. The system shall be certified in accordance with the provisions of section 4.1.2 of this appendix.

3.2.3 *Other Necessary Data Collection.* To convert measured hourly Hg concentrations to the units of the applicable emissions standard (*i.e.,* lb/TBtu or lb/GWh), additional data must be collected, as described in paragraphs 3.2.3.1 through 3.2.3.3 of this section. Any additional monitoring systems needed for this purpose must be certified, operated, maintained, and quality-assured according to the applicable provisions of part 75 of this chapter (see §§ 63.10010(b) through (d)). The calculation methods for the types of emission limits described in paragraphs 3.2.3.1 and 3.2.3.2 of this section are presented in section 6.2 of this appendix.

3.2.3.1 *Heat Input-Based Emission Limits.* For a heat input-based Hg emission limit (*i.e.,* in lb/TBtu), data from a certified CO_2 or O_2 monitor are needed, along with a fuel-specific F-factor and a conversion constant to convert measured Hg concentration values to the units of the standard. In some cases, the stack gas moisture content must also be considered in making these conversions.

3.2.3.2 *Electrical Output-Based Emission Rates.* If the applicable Hg limit is electrical output-based (*i.e.,* lb/GWh), hourly electrical load data and unit operating times are required in addition to hourly data from a certified stack gas flow rate monitor and (if applicable) moisture data.

3.2.3.3 *Sorbent Trap Monitoring System Operation.* Routine operation of a sorbent trap monitoring system requires the use of a certified stack gas flow rate monitor, to maintain an established ratio of stack gas flow rate to sample flow rate.

4. Certification and Recertification Requirements

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.10005(g).

4.1.1 *Hg CEMS.* Table A–1, below, summarizes the certification test requirements and performance specifications for a Hg CEMS. The CEMS may not be used to report quality-assured data until these performance criteria are met. Paragraphs 4.1.1.1 through 4.1.1.5 of this section provide specific instructions for the required tests. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the certification tests.

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Either elemental or oxidized NIST-traceable Hg standards (as defined in sections 3.1.4 and 3.1.5 of this appendix) may be used for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over nonconsecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.,* resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.2 *Linearity Check.* Perform the linearity check using low, mid, and high-level concentrations of NIST-traceable elemental Hg standards. Three gas injections at each concentration level are required, with no two successive injections at the same concentration level. Introduce the calibration gas at the gas injection port, as specified in section 3.2.1.1.3.6 of this appendix. Operate the CEMS at its normal operating temperature and conditions. Pass the calibration gas through all filters, scrubbers, conditioners, and other components used during normal sampling, and through as much of the sampling probe as is practical. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Record the monitor response from the data acquisition and handling system for each gas injection. At each concentration level, use the average analyzer response to calculate the linearity error (LE), as described in Table A–1. The LE must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A–1. The SIE must either meet the main performance specification or the alternative specification in Table A–1. (**Note:** This test is not required if the CEMS does not have a converter).

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR Hg CEMS

For this required certification test . . .	The main performance specification[1] is . . .	The alternate performance specification[1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test[2]	$\|R - A\| \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$\|R - A\| \leq 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check[3]	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high).	$\|R - A_{avg}\| \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check[4]	$\|R - A_{avg}\| \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$\|R - A_{avg}\| \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	$\|RM_{avg} - C_{avg}\| \leq 1.0$ µg/scm**	$RM_{avg} < 5.0$ µg/scm.
Cycle time test[2]	15 minutes.[5]		

[1] Note that $|R - A|$ is the absolute value of the difference between the reference gas value and the analyzer reading. $|R - A_{avg},|$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

[2] Use either elemental or oxidized Hg standards; a mid-level or high-level upscale gas may be used. This test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.

[3] Use elemental Hg standards.

[4] Use oxidized Hg standards. Not required if the CEMS does not have a converter.

[5] Stability criteria—Readings change by <2.0% of span *or* by ≤0.5 µg/scm, for 2 minutes.

** Note that $|RM_{avg} - C_{avg}|$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. The arithmetic difference between RM_{avg} and C_{avg} can be either + or −.

4.1.1.4 *Cycle Time Test.* Perform the cycle time test, using a zero-level gas and a high-level calibration gas.

Either an elemental or oxidized NIST-traceable Hg standard may be used as the high-level gas. Perform the test in two stages—upscale and downscale. The slower of the upscale and downscale response times is the cycle time for the CEMS. Begin each stage of the test by injecting calibration gas after achieving a stable reading of the stack emissions. The cycle time is the amount of time it takes for the analyzer to register a reading that is 95 percent of the way between the stable stack emissions reading and the final, stable reading of the calibration gas concentration. Use the following criterion to determine when a stable reading of stack emissions or calibration gas has been attained—the reading is stable if it changes by no more than 2.0 percent of the span value or 0.5 µg/scm (whichever is less restrictive) for two minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Integrated batch sampling type Hg CEMS are exempted from this test; however, these systems must be capable of delivering a measured Hg concentration reading at least once every 15 minutes. If necessary to increase measurement sensitivity of a batch sampling type Hg CEMS for a specific application, you may petition the Administrator for approval of a time longer than 15 minutes between readings.

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784–02 (Reapproved 2008), ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)'' (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A–8 to part 60. When Method 29 or ASTM D6784–02 is used, paired sampling trains are required. To validate a Method 29 or ASTM D6784–02 test run, calculate the relative deviation (RD) using Equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the average concentration is ≤ 1.0 µg/dscm, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the two Hg concentrations does not exceed 0.2 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a - C_b|}{C_a + C_b} x 100 \quad \text{(Eq. A-1)}$$

Where:

RD = Relative deviation between the Hg concentrations of samples ''a'' and ''b'' (percent)

C_a = Hg concentration of Hg sample ''a'' (µg/dscm)

C_b = Hg concentration of Hg sample ''b'' (µg/dscm)

4.1.1.5.1 *Special Considerations.* A minimum of nine valid test runs must be performed, directly comparing the CEMS measurements to the reference method. More than nine test runs may be performed. If this option is chosen, the results from a maximum of three test runs may be rejected so long as the total number of test results used to determine the relative accuracy is greater than or equal to nine; however, all data must be reported including the rejected data. The minimum time per run is 21 minutes if Method 30A is used. If Method 29, Method 30B, or ASTM D6784–02 (Reapproved 2008), ''Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)'' (incorporated by reference, see § 63.14) is used, the time per run must be long enough to collect a sufficient mass of Hg to analyze. Complete the RATA within 168 unit operating hours, except when Method 29 or ASTM D6784–02 is used, in which case up to 336 operating hours may be taken to finish the test.

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A–1.

4.1.1.5.3 *Bias Adjustment.* Measurement or adjustment of Hg CEMS data for bias is not required.

4.1.2 *Sorbent Trap Monitoring Systems.* For the initial certification of a sorbent trap monitoring system, only a RATA is required.

4.1.2.1 *Reference Methods.* The acceptable reference methods for the RATA of a sorbent trap monitoring system are the same as those listed in paragraph 4.1.1.5 of this section.

4.1.2.2 ''The special considerations specified in paragraph 4.1.1.5.1 of this section apply to the RATA of a sorbent trap monitoring system. During the RATA, the monitoring system must be operated and quality-assured in accordance with Performance Specification (PS) 12B in Appendix B to part 60 of this chapter with the following exceptions for sorbent trap section 2 breakthrough:

4.1.2.2.1 For stack Hg concentrations >1 µg/dscm, ≤10% of section 1 Hg mass;

4.1.2.2.2 For stack Hg concentrations ≤1 µg/dscm and >0.5 µg/dscm, ≤ 20% of section 1 Hg mass;

4.1.2.2.3 For stack Hg concentrations ≤0.5 µg/dscm and >0.1 µg/dscm, ≤ 50% of section 1 Hg mass; and

4.1.2.2.4 For stack Hg concentrations ≤0.1µg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

4.1.2.3 The type of sorbent material used by the traps during the RATA must be the same as for daily operation of the monitoring system; however, the size of the traps used for the RATA may be smaller than the traps used for daily operation of the system.

4.1.2.4 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the sorbent trap monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2). For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent moisture basis, either wet or dry.The main and alternative RATA performance specifications in Table A–1 for Hg CEMS also apply to the sorbent trap monitoring system.

4.1.2.5 *Bias Adjustment.* Measurement or adjustment of sorbent trap monitoring system data for bias is not required.

4.1.3 *Diluent Gas, Flow Rate, and/or Moisture Monitoring Systems.* Monitoring systems that are used to measure stack gas volumetric flow rate, diluent gas concentration, or stack gas moisture content, either for routine operation of a sorbent trap monitoring system or to convert Hg concentration data to units of the applicable emission limit, must be certified in accordance with the applicable provisions of part 75 of this chapter.

4.2 *Recertification.* Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS or sorbent trap monitoring system that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. Ongoing Quality Assurance (QA) and Data Validation

5.1 *Hg CEMS.*

5.1.1 *Required QA Tests.* Periodic QA testing of each Hg CEMS is required following initial certification. The required QA tests, the test frequencies, and the performance specifications that must be met are summarized in Table A–2, below. All tests must be performed with the affected unit(s) operating (*i.e.,* combusting fuel). Except for the RATA, which must be performed at normal load, no particular load level is required for the tests. For each test, follow the same basic procedures in section 4.1.1 of this appendix that were used for initial certification.

5.1.2 *Test Frequency.* The frequency for the required QA tests of the Hg CEMS shall be as follows:

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use either NIST-traceable elemental Hg standards or NIST-traceable oxidized Hg standards for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

5.1.2.2 Perform a linearity check of the Hg CEMS in each QA operating quarter, using low-level, mid-level, and high-level NIST-traceable elemental Hg standards. For units that operate infrequently, limited exemptions from this test are allowed for ‘‘non-QA operating quarters’’. A maximum of three consecutive exemptions for this reason are permitted, following the quarter of the last test. After the third consecutive exemption, a linearity check must be performed in the next calendar quarter or within a grace period of 168 unit or stack operating hours after the end of that quarter. The test frequency for 3-level system integrity checks (if performed in lieu of linearity checks) is the same as for the linearity checks. Use low-level, mid-level, and high-level NIST-traceable oxidized Hg standards for the system integrity checks.

5.1.2.3 If required, perform a single-level system integrity check weekly, *i.e.,* once every 7 operating days (see the third column in Table A–2).

5.1.2.4 The test frequency for the RATAs of the Hg CEMS shall be annual, *i.e.,* once every four QA operating quarters. For units that operate infrequently, extensions of RATA deadlines are allowed for non-QA operating quarters. Following a RATA, if there is a subsequent non-QA quarter, it extends the deadline for the next test by one calendar quarter. However, there is a limit to these extensions; the deadline may not be extended beyond the end of the eighth calendar quarter after the quarter of the last test. At that point, a RATA must either be performed within the eighth calendar quarter or in a 720 hour unit or stack operating hour grace period following that quarter. When a required annual RATA is done within a grace period, the deadline for the next RATA is three QA operating quarters after the quarter in which the grace period test is performed.

5.1.3 *Grace Periods.*

5.1.3.1 A 168 unit or stack operating hour grace period is available for quarterly linearity checks and 3-level system integrity checks of the Hg CEMS.

5.1.3.2 A 720 unit or stack operating hour grace period is available for RATAs of the Hg CEMS.

5.1.3.3 There is no grace period for weekly system integrity checks. The test must be completed once every 7 operating days.

5.1.4 *Data Validation.* The Hg CEMS is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any one of the acceptance criteria for the required QA tests in Table A–2 is not met. The CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.1.5 *Conditional Data Validation.* For certification, recertification, and diagnostic testing of Hg monitoring systems, and for the required QA tests when non-redundant backup Hg monitoring systems or temporary like-kind Hg analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete 7-day calibration error tests, linearity checks, cycle time tests, and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter. Required system integrity checks must be completed within 168 unit or stack operating hours after the probationary calibration error test.

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	• Use either a mid- or high-level gas. • Use either elemental or oxidized Hg.	$\lvert R - A \rvert \leq 5.0\%$ of span value. *or* $\lvert R - A \rvert \leq 1.0$ µg/scm.

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS—Continued

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
		• Calibrations are not required when the unit is not in operation.	
Single-level system integrity check	Weekly[1]	• Required only for systems with converters. • Use oxidized Hg—either mid- or high-level. • Not required if daily calibrations are done with a NIST-traceable source of oxidized Hg.	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas value. *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
Linearity check *or* 3-level system integrity check	Quarterly[3]	• Required in each "QA operating quarter"[2]—and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check. • For system integrity check, CEMS must have a converter.	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas value, at each calibration gas level. *or* $\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm.
RATA	Annual[4]	• Test deadline may be extended for "non-QA operating quarters", up to a maximum of 8 quarters from the quarter of the previous test. • 720 operating hour grace period available.	20.0% RA. *or* $\lvert RM_{avg} - C_{avg} \rvert \leq 1.0$ µg/scm, *if* $RM_{avg} < 5.0$ µg/scm.

[1] "Weekly" means once every 7 operating days.

[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.

[3] "Quarterly" means once every QA operating quarter.

[4] "Annual" means once every four QA operating quarters.

5.1.6 *Adjustment of Span.* If you discover that a span adjustment is needed (*e.g.,* if the Hg concentration readings exceed the span value for a significant percentage of the unit operating hours in a calendar quarter), you must implement the span adjustment within 90 days after the end of the calendar quarter in which you identify the need for the adjustment. A diagnostic linearity check is required within 168 unit or stack operating hours after changing the span value.

5.2 *Sorbent Trap Monitoring Systems.*

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.2.2 For ongoing QA, periodic RATAs of the system are required.

5.2.2.1 The RATA frequency shall be annual, *i.e.,* once every four QA operating quarters. The provisions in section 5.1.2.4 of this appendix pertaining to RATA deadline extensions also apply to sorbent trap monitoring systems.

5.2.2.2 The same RATA performance criteria specified in Table A–4 for Hg CEMS shall apply to the annual RATAs of the sorbent trap monitoring system.

5.2.2.3 A 720 unit or stack operating hour grace period is available for RATAs of the monitoring system.

5.2.3 Data validation for sorbent trap monitoring systems shall be done in accordance with Table 12B–1 in Performance Specification (PS) 12B in appendix B to part 60 of this chapter. All periods of invalid data shall be counted as hours of monitoring system downtime.

5.3 *Flow Rate, Diluent Gas, and Moisture Monitoring Systems.* The on-going QA test requirements for these monitoring systems are specified in part 75 of this chapter (see §§ 63.10010(b) through (d)).

5.4 *QA/QC Program Requirements.* The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the Hg CEMS and/or sorbent trap monitoring systems that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the diluent gas, flow rate, and moisture monitoring systems described in section 3.2.1.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

5.4.1 *General Requirements.*

5.4.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the Hg CEMS and/or sorbent trap monitoring system(s) in proper operating condition and a schedule for those procedures. Include, at a minimum, all procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

5.4.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

5.4.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any Hg CEMS or sorbent trap monitoring system in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded (*e.g.,* changing the dilution ratio of a CEMS), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

5.4.2 *Specific Requirements for Hg CEMS.*

5.4.2.1 *Daily Calibrations, Linearity Checks and System Integrity Checks.* Keep a written record of the procedures used for daily calibrations of the Hg CEMS. If moisture and/or chlorine is added to the Hg calibration gas, document how the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration is accounted for in an appropriate manner. Also keep records of the procedures used to perform linearity checks of the Hg CEMS and the procedures for system integrity checks of the Hg CEMS. Document how the test results are calculated and evaluated.

5.4.2.2 *Monitoring System Adjustments.* Document how each component of the Hg CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

5.4.2.3 *Relative Accuracy Test Audits.* Keep a written record of procedures used for RATAs of the Hg CEMS. Indicate the reference methods used and document how the test results are calculated and evaluated.

5.4.3 *Specific Requirements for Sorbent Trap Monitoring Systems.*

5.4.3.1 *Sorbent Trap Identification and Tracking.* Include procedures for inscribing or otherwise permanently marking a unique identification number on each sorbent trap, for chain of custody purposes. Keep records of the ID of the monitoring system in which each sorbent trap is used, and the dates and hours of each Hg collection period.

5.4.3.2 *Monitoring System Integrity and Data Quality.* Document the procedures used to perform the leak checks when a sorbent trap is placed in service and removed from service. Also Document the other QA procedures used to ensure system integrity and data quality, including, but not limited to, gas flow meter calibrations, verification of moisture removal, and ensuring air-tight pump operation. In addition, the QA plan must include the data acceptance and quality control criteria in Table 12B–1 in section 9.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter. All reference meters used to calibrate the gas flow meters (*e.g.,* wet test meters) shall be periodically recalibrated. Annual, or more frequent, recalibration is recommended. If a NIST-traceable calibration device is used as a reference flow meter, the QA plan must include a protocol for ongoing maintenance and periodic recalibration to maintain the accuracy and NIST-traceability of the calibrator.

5.4.3.3 *Hg Analysis.* Explain the chain of custody employed in packing, transporting, and analyzing the sorbent traps. Keep records of all Hg analyses. The analyses shall be performed in accordance with the procedures described in section 11.0 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter.

5.4.3.4 *Data Collection Period.* State, and provide the rationale for, the minimum acceptable data collection period (*e.g.,* one day, one week, etc.) for the size of sorbent trap selected for the monitoring. Address such factors as the Hg concentration in the stack gas, the capacity of the sorbent trap, and the minimum mass of Hg required for the analysis. Each pair of sorbent traps may be used to sample the stack gas for up to 14 operating days.

5.4.3.5 *Relative Accuracy Test Audit Procedures.* Keep records of the procedures and details peculiar to the sorbent trap monitoring systems that are to be followed for relative accuracy test audits, such as sampling and analysis methods.

6. Data Reduction and Calculations

6.1 Data Reduction.

6.1.1 Reduce the data from Hg CEMS to hourly averages, in accordance with § 60.13(h)(2) of this chapter.

6.1.2 For sorbent trap monitoring systems, determine the Hg concentration for each data collection period and assign this concentration value to each operating hour in the data collection period.

6.1.3 For any operating hour in which valid data are not obtained, either for Hg concentration or for a parameter used in the emissions calculations (*i.e.,* flow rate, diluent gas concentration, or moisture, as applicable), do not calculate the Hg emission rate for that hour. For the purposes of this appendix, part 75 substitute data values are not considered to be valid data.

6.1.4 Operating hours in which valid data are not obtained for Hg concentration are considered to be hours of monitor downtime. The use of substitute data for Hg concentration is not required.

6.2 *Calculation of Hg Emission Rates.* Use the applicable calculation methods in paragraphs 6.2.1 and 6.2.2 of this section to convert Hg concentration values to the appropriate units of the emission standard.

6.2.1 *Heat Input-Based Hg Emission Rates.* Calculate hourly heat input-based Hg emission rates, in units of lb/TBtu, according to sections 6.2.1.1 through 6.2.1.4 of this appendix.

6.2.1.1 Select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter.

6.2.1.2 Calculate the Hg emission rate in lb/MMBtu, using the equation selected from Method 19. Multiply the Hg concentration value by 6.24×10^{-11} to convert it from µg/scm to lb/scf. In cases where an appropriate F-factor is not listed in Table 19–2 of Method 19, you may use F-factors from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or F-factors derived using the procedures in section 3.3.6 of appendix to part 75 of this chapter. Also, for startup and shutdown hours, you may calculate the Hg emission rate using the applicable diluent cap value specified in section 3.3.4.1 of appendix F to part 75 of this chapter, provided that the diluent gas monitor is not out-of-control and the hourly average O_2 concentration is above 14.0% O_2 (19.0% for an IGCC) or the hourly average CO_2 concentration is below 5.0% CO_2 (1.0% for an IGCC), as applicable.

6.2.1.3 Multiply the lb/MMBtu value obtained in section 6.2.1.2 of this appendix by 10^6 to convert it to lb/TBtu.

6.2.1.4 The heat input-based Hg emission rate limit in Table 2 to this subpart must be met on a 30 boiler operating day rolling average basis. Use Equation 19–19 in EPA Method 19 to calculate the Hg emission rate for each averaging period. The term E_{hj} in Equation 19–19 must be in the units of the applicable emission limit. Do not include non-operating hours with zero emissions in the average.

6.2.2 *Electrical Output-Based Hg Emission Rates.* Calculate electrical output-based Hg emission limits in units of lb/GWh, according to sections 6.2.2.1 through 6.2.2.3 of this appendix.

6.2.2.1 Calculate the Hg mass emissions for each operating hour in which valid data are obtained for all parameters, using Equation A–2 of this section (for wet-basis measurements of Hg concentration) or Equation A–3 of this section (for dry-basis measurements), as applicable:

$$M_h = K C_h Q_h \qquad \text{(Equation A-2)}$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf,

C_h = Hourly average Hg concentration, wet basis (µg/scm)

Q_h = Stack gas volumetric flow rate for the hour (scfh).

(**Note:** Use unadjusted flow rate values; bias adjustment is not required)

$$M_h = K C_h Q_h \left(1 - B_{ws}\right) \qquad \text{(Equation A-3)}$$

Where:

M_h = Hg mass emission rate for the hour (lb/h)

K = Units conversion constant, 6.24×10^{-11} lb-scm/µg-scf.

C_h = Hourly average Hg concentration, dry basis (µg/dscm).

Q_h = Stack gas volumetric flow rate for the hour (scfh)

(**Note:** Use unadjusted flow rate values; bias adjustment is not required).

B_{ws} = Moisture fraction of the stack gas, expressed as a decimal (equal to % H_2O/100)

6.2.2.2 Use Equation A–4 of this section to calculate the emission rate for each unit or stack operating hour in which valid data are obtained for all parameters.

$$E_{ho} = \frac{M_h}{(MW)_h} x\, 10^3 \qquad \texttt{(Equation A-4)}$$

Where:

E_{ho} = Electrical output-based Hg emission rate (lb/GWh).

M_h = Hg mass emission rate for the hour, from Equation A–2 or A–3 of this section, as applicable (lb/h).

$(MW)_h$ = Gross electrical load for the hour, in megawatts (MW).

10^3 = Conversion factor from megawatts to gigawatts.

6.2.2.3 The applicable electrical output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30-boiler operating day rolling average basis. Use Equation A–5 of this section to calculate the Hg emission rate for each averaging period.

$$\overline{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \qquad \texttt{(Equation A-5)}$$

Where:

$\bar{E}_o$ = Hg emission rate for the averaging period (lb/GWh).

E_{ho} = Electrical output-based hourly Hg emission rate for unit or stack operating hour ‘‘h’’ in the averaging period, from Equation A–4 of this section (lb/GWh).

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters (**Note:** Do *not* include non-operating hours with zero emission rates in the average).

7. Recordkeeping and Reporting

7.1 *Recordkeeping Provisions.* For the Hg CEMS and/or sorbent trap monitoring systems and any other necessary monitoring systems installed at each affected unit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 7.1.1 through 7.1.10 of this section.

7.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the Hg CEMS and/or sorbent trap monitoring system(s) and any other monitoring system(s) (*i.e.,* flow rate, diluent gas, or moisture systems) needed for routine operation of a sorbent trap monitoring system or to convert Hg concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall Document how the data derived from these systems ensure that all Hg emissions from the unit or stack are monitored and reported.

7.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

7.1.1.2 *Contents of the Monitoring Plan.* For Hg CEMS and sorbent trap monitoring systems, the monitoring plan shall contain the information in sections 7.1.1.2.1 and 7.1.1.2.2 of this appendix, as applicable. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the information required for those systems under § 75.53 (g) of this chapter.

7.1.1.2.1 *Electronic.* The electronic monitoring plan records must include the following: unit or stack ID number(s); monitoring location(s); the Hg monitoring methodologies used; Hg monitoring system information, including, but not limited to: Unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate Hg emissions; Hg monitor span and range information The electronic monitoring plan shall be evaluated and submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

7.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the Hg monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations; miscellaneous technical justifications.

7.1.2 *Operating Parameter Records.* The owner or operator shall record the following information for each operating hour of each affected unit and also for each group of units utilizing a common stack, to the extent that these data are needed to convert Hg concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 7.1.2.1 and 7.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 7.1.2.1, 7.1.2.2, and (if applicable) 7.1.2.4 of this section.

7.1.2.1 The date and hour;

7.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

7.1.2.3 The hourly gross unit load (rounded to nearest MWe); and

7.1.2.4 If applicable, the F-factor used to calculate the heat input-based Hg emission rate.

7.1.3 *Hg Emissions Records (Hg CEMS).* For each affected unit or common stack using a Hg CEMS, the owner or operator shall record the following information for each unit or stack operating hour:

7.1.3.1 The date and hour;

7.1.3.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the CEMS provides a quality-assured value of Hg concentration for the hour;

7.1.3.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (µg/scm, rounded to three significant figures);

7.1.3.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour. This code may be entered manually when a temporary like-kind replacement Hg analyzer is used for reporting; and

7.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.4 *Hg Emissions Records (Sorbent Trap Monitoring Systems).* For each affected unit or common stack using a sorbent trap monitoring system, each owner or operator shall record the following information for the unit or stack operating hour in each data collection period:

7.1.4.1 The date and hour;

7.1.4.2 Monitoring system and component identification codes, as provided in the monitoring plan, if the sorbent trap system provides a quality-assured value of Hg concentration for the hour;

7.1.4.3 The hourly Hg concentration, if a quality-assured value is obtained for the hour (μg/scm, rounded to three significant figures). Note that when a quality-assured Hg concentration value is obtained for a particular data collection period, that single concentration value is applied to each operating hour of the data collection period.

7.1.4.4 A special code, indicating whether or not a quality-assured Hg concentration is obtained for the hour;

7.1.4.5 The average flow rate of stack gas through each sorbent trap (in appropriate units, *e.g.,* liters/min, cc/min, dscm/min);

7.1.4.6 The gas flow meter reading (in dscm, rounded to the nearest hundredth), at the beginning and end of the collection period and at least once in each unit operating hour during the collection period;

7.1.4.7 The ratio of the stack gas flow rate to the sample flow rate, as described in section 12.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter; and

7.1.4.8 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

7.1.5 *Stack Gas Volumetric Flow Rate Records.*

7.1.5.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required for routine operation of sorbent trap monitoring systems, to maintain the required ratio of stack gas flow rate to sample flow rate (see section 8.2.2 of Performance Specification (PS) 12B in Appendix B to part 60 of this chapter). Hourly stack gas flow rate data are also needed in order to demonstrate compliance with electrical output-based Hg emissions limits, as provided in section 6.2.2 of this appendix.

7.1.5.2 For each affected unit or common stack, if hourly measurements of stack gas flow rate are needed for sorbent trap monitoring system operation or to convert Hg concentrations to the units of the emission standard, use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

7.1.6 *Records of Stack Gas Moisture Content.*

7.1.6.1 Correction of hourly Hg concentration data for moisture is sometimes required when converting Hg concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

7.1.6.1.1 For sorbent trap monitoring systems;

7.1.6.1.2 For Hg CEMS that measure Hg concentration on a dry basis, when you must calculate electrical output-based Hg emission rates; and

7.1.6.1.3 When using certain equations from EPA Method 19 in appendix A–7 to part 60 of this chapter to calculate heat input-based Hg emission rates.

7.1.6.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage from § 75.11(b)(1) of this chapter or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

7.1.7 *Records of Diluent Gas (CO_2 or O_2)* Concentration.

7.1.7.1 When a heat input-based Hg mass emissions limit must be met, in units of lb/TBtu, hourly measurements of CO_2 or O_2 concentration are required to convert Hg concentrations to units of the standard.

7.1.7.2 If hourly measurements of diluent gas concentration are needed, use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

7.1.8 *Hg Emission Rate Records.* For applicable Hg emission limits in units of lb/TBtu or lb/GWh, record the following information for each affected unit or common stack:

7.1.8.1 The date and hour;

7.1.8.2 The hourly Hg emissions rate (lb/TBtu or lb/GWh, as applicable, calculated according to section 6.2.1 or 6.2.2 of this appendix, rounded to three significant figures), if valid values of Hg concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

7.1.8.3 An identification code for the formula (either the selected equation from Method 19 in section 6.2.1 of this appendix or Equation A–4 in section 6.2.2 of this appendix) used to derive the hourly Hg emission rate from Hg concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

7.1.8.4 A code indicating that the Hg emission rate was not calculated for the hour, if valid data for Hg concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

7.1.9 *Certification and Quality Assurance Test Records.* For any Hg CEMS and sorbent trap monitoring systems used to provide data under this subpart, record the following certification and quality-assurance information:

7.1.9.1 The reference values, monitor responses, and calculated calibration error (CE) values, and a flag to indicate whether the test was done using elemental or oxidized Hg, for all required 7-day calibration error tests and daily calibration error tests of the Hg CEMS;

7.1.9.2 The reference values, monitor responses, and calculated linearity error (LE) or system integrity error (SIE) values for all linearity checks of the Hg CEMS, and for all single-level and 3-level system integrity checks of the Hg CEMS;

7.1.9.3 The CEMS and reference method readings for each test run and the calculated relative accuracy results for all RATAs of the Hg CEMS and/or sorbent trap monitoring systems;

7.1.9.4 The stable stack gas and calibration gas readings and the calculated results for the upscale and downscale stages of all required cycle time tests of the Hg CEMS or, for a batch sampling Hg CEMS, the interval between measured Hg concentration readings;

7.1.9.5 Supporting information for all required RATAs of the Hg monitoring systems, including records of the test dates, the raw reference method and monitoring system data, the results of sample analyses to substantiate the reported test results, and records of sampling equipment calibrations;

7.1.9.6 For sorbent trap monitoring systems, also keep records of the results of all analyses of the sorbent traps used for routine daily operation of the system, and information documenting the results of all leak checks and the other applicable quality control procedures described in Table 12B–1 of Performance Specification (PS) 12B in appendix B to part 60 of this chapter.

7.1.9.7 For stack gas flow rate, diluent gas, and (if applicable) moisture monitoring systems, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59 of this chapter.

7.2 *Reporting Requirements.*

7.2.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting Hg emissions from each affected unit (or group of units monitored at a common stack) under this subpart:

7.2.1.1 Notifications, in accordance with paragraph 7.2.2 of this section;

7.2.1.2 Monitoring plan reporting, in accordance with paragraph 7.2.3 of this section;

7.2.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 7.2.4 of this section; and

7.2.1.4 Electronic quarterly report submittals, in accordance with paragraph 7.2.5 of this section.

7.2.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) under this subpart in accordance with § 63.10030.

7.2.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) under this subpart using Hg CEMS or sorbent trap monitoring system to measure Hg emissions, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

7.2.3.1 Submit the electronic and hard copy information in section 7.1.1.2 of this appendix pertaining to the Hg monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also submit the monitoring plan information in § 75.53.(g) pertaining to the flow rate, diluent gas, and moisture monitoring systems within that same time frame, if the required records are not already in place.

7.2.3.2 Whenever an update of the monitoring plan is required, as provided in paragraph 7.1.1.1 of this section. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

7.2.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 7.1 of this appendix.

7.2.4 *Certification, Recertification, and Quality-Assurance Test Reporting.* Except for daily QA tests of the required monitoring systems (*i.e.,* calibration error tests and flow monitor interference checks), the results of all required certification, recertification, and quality-assurance tests described in paragraphs 7.1.10.1 through 7.1.10.7 of this section (except for test results previously submitted, *e.g.,* under the ARP) shall be submitted electronically, using the ECMPS Client Tool, either prior to or concurrent with the relevant quarterly electronic emissions report.

7.2.5 *Quarterly Reports.*

7.2.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.9984, the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack) under this subpart.

7.2.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

7.2.5.3 Each electronic quarterly report shall include the following information:

7.2.5.3.1 The date of report generation;

7.2.5.3.2 Facility identification information;

7.2.5.3.3 The information in paragraphs 7.1.2 through 7.1.8 of this section, as applicable to the Hg emission measurement methodology (or methodologies) used and the units of the Hg emission standard(s); and

7.2.5.3.4 The results of all daily calibration error tests of the Hg CEMS, as described in paragraph 7.1.90.1 of this section and (if applicable) the results of all daily flow monitor interference checks.

7.2.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all Hg emissions from the affected unit(s) under this subpart have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

Appendix B to Subpart UUUUU—-HCl and HF Monitoring Provisions

1. Applicability

These monitoring provisions apply to the measurement of HCl and/or HF emissions from electric utility steam generating units, using CEMS. The CEMS must be capable of measuring HCl and/or HF in the appropriate units of the applicable emissions standard (e.g., lb/MMBtu, lb/MWh, or lb/GWh).

2. Monitoring of HCl and/or HF Emissions

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems in appendix B to part 60 of this chapter and § 63.10010(a).

2.2 *Primary and Backup Monitoring Systems.* The provisions pertaining to primary and redundant backup monitoring systems in section 2.2 of appendix A to this subpart apply to HCl and HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit.

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The provisions of Performance Specification 15 Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 apply.

3. Initial Certification Procedures

The initial certification procedures for the HCl or HF CEMS used to provide data under this subpart are as follows:

3.1 The HCl and/or HF CEMS must be certified according to Performance Specification 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below. (**Please Note:** EPA plans to publish a technology neutral performance specification and appropriate on-going quality-assurance requirements for HCl CEMS in the near future along with amendments to this appendix to accommodate their use.)

3.1.1 You must conduct a gas audit of the HCl and/or HF CEMS as described in section 9.1 of Performance Specification 15, with the exceptions listed in sections 3.1.2.1 and 3.1.2.2 below.

3.1.1.1 The audit sample gas does not have to be obtained from the Administrator; however, it must be (1) from a secondary source of certified gases (i.e., independent of any calibration gas used for the daily calibration assessments) and (2) directly traceable to National Institute of Standards and Technology (NIST) or VSL Dutch Metrology Institute (VSL) reference materials through an unbroken chain of comparisons. If audit gas traceable to NIST or VSL reference materials is not available, you may use a gas with a concentration certified to a specified uncertainty by the gas manufacturer.

3.1.1.2 Analyze the results of the gas audit using the calculations in section 12.1 of Performance Specification 15. The calculated correction factor (CF) from Eq. 6 of Performance Specification 15 must be between 0.85 and 1.15. You do not have to test the bias for statistical significance.

3.1.2 You must perform a relative accuracy test audit or RATA according to section 11.1.1.4 of Performance Specification 15 and the requirements below. Perform the RATA of the HCl or HF CEMS at normal load. Acceptable HCl/HF reference methods (RM) are Methods 26 and 26A in appendix A–8 to part 60 of this chapter, Method 320 in Appendix A to this part, or ASTM D6348–03 (Reapproved 2010) ''Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy'' (incorporated by reference, see § 63.14), each applied based on the criteria set forth in Table 5 of this subpart.

3.1.2.1 When ASTM D6348–03 is used as the RM, the following conditions must be met:

3.1.2.1.1 The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory;

3.1.2.1.2 In ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (see Equation A5.5);

3.1.2.1.3 For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be $70\% \geq R \leq 130\%$; and

3.1.2.1.4 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:

$$\text{Reported Result} = \frac{(\text{Measured Concentration in Stack})}{\%R} \, x \, 100 \qquad \text{(Eq. B-1)}$$

3.1.2.2 The relative accuracy (RA) of the HCl or HF CEMS must be no greater than 20 percent of the mean value of the RM test data in units of ppm on the same moisture basis. Alternatively, if the mean RM value is less than 1.0 ppm, the RA results are acceptable if the absolute value of the difference between the mean RM and CEMS values does not exceed 0.20 ppm.

3.2 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

4. Recertification Procedures

Whenever the owner or operator makes a replacement, modification, or change to a certified CEMS that may significantly affect the ability of the system to accurately measure or record pollutant or diluent gas concentrations, stack gas flow rates, or stack gas moisture content, the owner or operator shall recertify the monitoring system. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the concentration or flow profile, the owner or operator shall recertify the monitoring system. The same tests performed for the initial certification of the monitoring system shall be repeated for recertification, unless otherwise specified by the Administrator. Examples of changes that require recertification include: Replacement of a gas analyzer; complete monitoring system replacement, and changing the location or orientation of the sampling probe.

5. On-Going Quality Assurance Requirements

5.1 For on-going QA test requirements for HCl and HF CEMS, implement the quality assurance/quality control procedures of Performance Specification 15 of appendix B to part 60 of this chapter as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

5.1.1 On a daily basis, you must assess the calibration error of the HCl or HF CEMS using either a calibration transfer standard as specified in Performance Specification 15 Section 10.1 which references Section 4.5 of the FTIR Protocol or a HCl and/or HF calibration gas at a concentration no greater than two times the level corresponding to the applicable emission limit. A calibration transfer standard is a substitute calibration compound chosen to ensure that the FTIR is performing well at the wavelength regions used for analysis of the target analytes. The measured concentration of the calibration transfer standard or HCl and/or HF calibration gas results must agree within ± 5 percent of the reference gas value after correction for differences in pressure.

5.1.2 On a quarterly basis, you must conduct a gas audit of the HCl and/or HF CEMS as described in section 3.1.1 of this appendix. For the purposes of this appendix, ''quarterly'' means once every ''QA operating quarter'' (as defined in section 3.1.20 of appendix A to this subpart). You have the option to use HCl gas in lieu of HF gas for conducting this audit on an HF CEMS. To the extent practicable, perform consecutive quarterly gas audits at least 30 days apart. The initial quarterly audit is due in the first QA operating quarter following the calendar quarter in which certification testing of the CEMS is successfully completed. Up to three consecutive exemptions from the quarterly audit requirement are allowed for ''non-QA operating quarters'' (*i.e.,* calendar quarters in which there are less than 168 unit or stack operating hours). However, no more than four consecutive calendar quarters may elapse without performing a gas audit, except as otherwise provided in section 5.3.3.2.1 of this appendix.

5.1.3 You must perform an annual relative accuracy test audit or RATA of the HCl or HF CEMS as described in section 3.1.2 of this appendix. Perform the RATA at normal load. For the purposes of this appendix, ''annual'' means once every four ''QA operating quarters'' (as defined in section 3.1.20 of appendix A to this subpart). The first annual RATA is due within four QA operating quarters following the calendar quarter in which the initial certification testing of the HCl or HF CEMS is successfully completed. The provisions in section 5.1.2.4 of appendix A to this subpart pertaining to RATA deadline extensions also apply.

5.2 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

5.3 *Data Validation.*

5.3.1 *Out-of-Control Periods.* A HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.3.2 *Grace Periods.* For the purposes of this appendix, a ''grace period'' is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.3.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.2 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.3.2.2 For the purposes of this appendix, if the deadline for a required gas audit or RATA of a HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.3.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit; or

5.3.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.3.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.3.2.3.1 For a gas audit or RATA of the monitoring systems described in section 5.1 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.3.2.3.2 For the gas audit of a HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit is required for that quarter.

5.3.2.3.3 For the RATA of a HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.3.4 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in §§ 75.20(b)(3)(ii) through (b)(3)(ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

6. Missing Data Requirements

For the purposes of this appendix, the owner or operator of an affected unit shall not substitute for missing data from HCl or HF CEMS. Any process operating hour for which quality-assured HCl or HF concentration data are not obtained is counted as an hour of monitoring system downtime.

7. Bias Adjustment

Bias adjustment of hourly emissions data from a HCl or HF CEMS is not required.

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in section 5.2 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

8.1 *General Requirements for HCl and HF CEMS.*

8.1.1 *Preventive Maintenance.* Keep a written record of procedures needed to maintain the HCl and/or HF CEMS in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

8.1.2 *Recordkeeping and Reporting.* Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements of this appendix.

8.1.3 *Maintenance Records.* Keep a record of all testing, maintenance, or repair activities performed on any HCl or HF CEMS in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: Date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor outage period. Additionally, any adjustment that may significantly affect a system's ability to accurately measure emissions data must be recorded and a written explanation of the procedures used to make the adjustment(s) shall be kept.

8.2 *Specific Requirements for HCl and HF CEMS.* The following requirements are specific to HCl and HF CEMS:

8.2.1 Keep a written record of the procedures used for each type of QA test required for each HCl and HF CEMS. Explain how the results of each type of QA test are calculated and evaluated.

8.2.2 Explain how each component of the HCl and/or HF CEMS will be adjusted to provide correct responses to calibration gases after routine maintenance, repairs, or corrective actions.

9. Data Reduction and Calculations

9.1 Design and operate the HCl and/or HF CEMS to complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

9.2 Reduce the HCl and/or HF concentration data to hourly averages in accordance with § 60.13(h)(2) of this chapter.

9.3 Convert each hourly average HCl or HF concentration to an HCl or HF emission rate expressed in units of the applicable emissions limit.

9.3.1 For heat input-based emission rates, select an appropriate emission rate equation from among Equations 19–1 through 19–9 in EPA Method 19 in appendix A–7 to part 60 of this chapter, to calculate the HCl or HF emission rate in lb/MMBtu. Multiply the HCl concentration value (ppm) by 9.43×10^{-8} to convert it to lb/scf, for use in the applicable Method 19 equation. For HF, the conversion constant from ppm to lb/scf is 5.18×10^{-8}.

9.3.2 For electrical output-based emission rates, first calculate the HCl or HF mass emission rate (lb/h), using an equation that has the general form of Equation A–2 or A–3 in appendix A to this subpart (as applicable), replacing the value of K with 9.43×10^{-8} lb/scf-ppm (for HCl) or 5.18×10^{-8} (for HF) and defining C_h as the hourly average HCl or HF concentration in ppm. Then, use Equation A–4 in appendix A to this subpart to calculate the HCl or HF emission rate in lb/GWh. If the applicable HCl or HF limit is expressed in lb/MWh, divide the result from Equation A–4 by 10^3.

9.4 Use Equation A–5 in appendix A of this subpart to calculate the required 30 operating day rolling average HCl or HF emission rates. Round off each 30 operating day average to two significant figures. The term E_{ho} in Equation A–5 must be in the units of the applicable emissions limit.

10. Recordkeeping Requirements

10.1 For each HCl or HF CEMS installed at an affected source, and for any other monitoring system(s) needed to convert pollutant concentrations to units of the applicable emissions limit, the owner or operator must maintain a file of all measurements, data, reports, and other information required by this appendix in a form suitable for inspection, for 5 years from the date of each record, in accordance with § 63.10033. The file shall contain the information in paragraphs 10.1.1 through 10.1.8 of this section.

10.1.1 *Monitoring Plan Records.* For each affected unit or group of units monitored at a common stack, the owner or operator shall prepare and maintain a monitoring plan for the HCl and/or HF CEMS and any other monitoring system(s) (*i.e,* flow rate, diluent gas, or moisture systems) needed to convert pollutant concentrations to units of the applicable emission standard. The monitoring plan shall contain essential information on the continuous monitoring systems and shall explain how the data derived from these systems ensure that all HCl or HF emissions from the unit or stack are monitored and reported.

10.1.1.1 *Updates.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous HCl or HF monitoring system that is used to provide data under this subpart (including a change in the automated data acquisition and handling system or the flue gas handling system) which affects information reported in the monitoring plan (*e.g.,* a change to a serial number for a component of a monitoring system), the owner or operator shall update the monitoring plan.

10.1.1.2 *Contents of the Monitoring Plan.* For HCl and/or HF CEMS, the monitoring plan shall contain the applicable electronic and hard copy information in sections 10.1.1.2.1 and 10.1.1.2.2 of this appendix. For stack gas flow rate, diluent gas, and moisture monitoring systems, the monitoring plan shall include the electronic and hard copy information required for those systems under § 75.53 (g) of this chapter. The electronic monitoring plan shall be evaluated using the ECMPS Client Tool.

10.1.1.2.1 *Electronic.* Record the unit or stack ID number(s); monitoring location(s); the HCl or HF monitoring methodology used (*i.e.,* CEMS); HCl or HF monitoring system information, including, but not limited to: unique system and component ID numbers; the make, model, and serial number of the monitoring equipment; the sample acquisition method; formulas used to calculate emissions; monitor span and range information (if applicable).

10.1.1.2.2 *Hard Copy.* Keep records of the following: schematics and/or blueprints showing the location of the monitoring system(s) and test ports; data flow diagrams; test protocols; monitor span and range calculations (if applicable); miscellaneous technical justifications.

10.1.2 *Operating Parameter Records.* For the purposes of this appendix, the owner or operator shall record the following information for each operating hour of each affected unit or group of units utilizing a common stack, to the extent that these data are needed to convert pollutant concentration data to the units of the emission standard. For non-operating hours, record only the items in paragraphs 10.1.2.1 and 10.1.2.2 of this section. If there is heat input to the unit(s), but no electrical load, record only the items in paragraphs 10.1.2.1, 10.1.2.2, and (if applicable) 10.1.2.4 of this section.

10.1.2.1 The date and hour;

10.1.2.2 The unit or stack operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator);

10.1.2.3 The hourly gross unit load (rounded to nearest MWge); and

10.1.2.4 If applicable, the F-factor used to calculate the heat input-based pollutant emission rate.

10.1.3 *HCl and/or HF Emissions Records.* For HCl and/or HF CEMS, the owner or operator must record the following information for each unit or stack operating hour:

10.1.3.1 The date and hour;

10.1.3.2 Monitoring system and component identification codes, as provided in the electronic monitoring plan, for each hour in which the CEMS provides a quality-assured value of HCl or HF concentration (as applicable);

10.1.3.3 The pollutant concentration, for each hour in which a quality-assured value is obtained. For HCl and HF, record the data in parts per million (ppm), rounded to three significant figures.

10.1.3.4 A special code, indicating whether or not a quality-assured HCl or HF concentration value is obtained for the hour. This code may be entered manually when a temporary like-kind replacement HCl or HF analyzer is used for reporting; and

10.1.3.5 Monitor data availability, as a percentage of unit or stack operating hours, calculated according to § 75.32 of this chapter.

10.1.4 *Stack Gas Volumetric Flow Rate Records.*

10.1.4.1 Hourly measurements of stack gas volumetric flow rate during unit operation are required to demonstrate compliance with electrical output-based HCl or HF emissions limits (*i.e.,* lb/MWh or lb/GWh).

10.1.4.2 Use a flow rate monitor that meets the requirements of part 75 of this chapter to record the required data. You must keep hourly flow rate records, as specified in § 75.57(c)(2) of this chapter.

10.1.5 *Records of Stack Gas Moisture Content.*

10.1.5.1 Correction of hourly pollutant concentration data for moisture is sometimes required when converting concentrations to the units of the applicable Hg emissions limit. In particular, these corrections are required:

10.1.5.1.1 To calculate electrical output-based pollutant emission rates, when using a CEMS that measures pollutant concentrations on a dry basis; and

10.1.5.1.2 To calculate heat input-based pollutant emission rates, when using certain equations from EPA Method 19 in appendix A–7 to part 60 of this chapter.

10.1.5.2 If hourly moisture corrections are required, either use a fuel-specific default moisture percentage for coal-fired units from § 75.11(b)(1) of this chapter, an Administrator approved default moisture value for non-coal-fired units (as per paragraph 63.10010(d) of this subpart), or a certified moisture monitoring system that meets the requirements of part 75 of this chapter, to record the required data. If you elect to use a moisture monitoring system, you must keep hourly records of the stack gas moisture content, as specified in § 75.57(c)(3) of this chapter.

10.1.6 *Records of Diluent Gas (CO_2 or O_2) Concentration.*

10.1.6.1 To assess compliance with a heat input-based HCl or HF emission rate limit in units of lb/MMBtu, hourly measurements of CO_2 or O_2 concentration are required to convert pollutant concentrations to units of the standard.

10.1.6.2 If hourly measurements of diluent gas concentration are needed, you must use a certified CO_2 or O_2 monitor that meets the requirements of part 75 of this chapter to record the required data. For all diluent gas monitors, you must keep hourly CO_2 or O_2 concentration records, as specified in § 75.57(g) of this chapter.

10.1.7 *HCl and HF Emission Rate Records.* For applicable HCl and HF emission limits in units of lb/MMBtu, lb/MWh, or lb/GWh, record the following information for each affected unit or common stack:

10.1.7.1 The date and hour;

10.1.7.2 The hourly HCl and/or HF emissions rate (lb/MMBtu, lb/MWh, or lb/GWh, as applicable, rounded to three significant figures), for each hour in which valid values of HCl or HF concentration and all other required parameters (stack gas volumetric flow rate, diluent gas concentration, electrical load, and moisture data, as applicable) are obtained for the hour;

10.1.7.3 An identification code for the formula used to derive the hourly HCl or HF emission rate from HCl or HF concentration, flow rate, electrical load, diluent gas concentration, and moisture data (as applicable); and

10.1.7.4 A code indicating that the HCl or HF emission rate was not calculated for the hour, if valid data for HCl or HF concentration and/or any of the other necessary parameters are not obtained for the hour. For the purposes of this appendix, the substitute data values required under part 75 of this chapter for diluent gas concentration, stack gas flow rate and moisture content are not considered to be valid data.

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values, monitor responses, and calculated calibration error values;

10.1.8.1.2 For gas audits of HCl or HF CEMS, record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of Performance Specification 15, and the results of those calculations and analyses.

10.1.8.1.3 For each RATA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

10.1.8.2 *Additional Monitoring Systems.* For the stack gas flow rate, diluent gas, and moisture monitoring systems described in section 3.2 of this appendix, you must keep records of all certification, recertification, diagnostic, and on-going quality-assurance tests of these systems, as specified in § 75.59(a) of this chapter.

11. Reporting Requirements

11.1 *General Reporting Provisions.* The owner or operator shall comply with the following requirements for reporting HCl and/or HF emissions from each affected unit (or group of units monitored at a common stack):

11.1.1 Notifications, in accordance with paragraph 11.2 of this section;

11.1.2 Monitoring plan reporting, in accordance with paragraph 11.3 of this section;

11.1.3 Certification, recertification, and QA test submittals, in accordance with paragraph 11.4 of this section; and

11.1.4 Electronic quarterly report submittals, in accordance with paragraph 11.5 of this section.

11.2 *Notifications.* The owner or operator shall provide notifications for each affected unit (or group of units monitored at a common stack) in accordance with § 63.10030.

11.3 *Monitoring Plan Reporting.* For each affected unit (or group of units monitored at a common stack) using HCl and/or HF CEMS, the owner or operator shall make electronic and hard copy monitoring plan submittals as follows:

11.3.1 Submit the electronic and hard copy information in section 10.1.1.2 of this appendix pertaining to the HCl and/or HF monitoring systems at least 21 days prior to the applicable date in § 63.9984. Also, if applicable, submit monitoring plan information pertaining to any required flow rate, diluent gas, and/or moisture monitoring systems within that same time frame, if the required records are not already in place.

11.3.2 Update the monitoring plan when required, as provided in paragraph 10.1.1.1 of this appendix. An electronic monitoring plan information update must be submitted either prior to or concurrent with the quarterly report for the calendar quarter in which the update is required.

11.3.3 All electronic monitoring plan submittals and updates shall be made to the Administrator using the ECMPS Client Tool. Hard copy portions of the monitoring plan shall be kept on record according to section 10.1 of this appendix.

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*i.e.,* calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

11.4.1 For daily calibrations (including calibration transfer standard tests), report the information in § 75.59(a)(1) of this chapter, excluding paragraphs (a)(1)(ix) through (a)(1)(xi).

11.4.2 For each quarterly gas audit of a HCl or HF CEMS, report:

11.4.2.1 Facility ID information;

11.4.2.2 Monitoring system ID number;

11.4.2.3 Type of test (*e.g.,* quarterly gas audit);

11.4.2.4 Reason for test;

11.4.2.5 Certified audit (spike) gas concentration value (ppm);

11.4.2.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.2.7 Calculated dilution ratio for audit (spike) gas;

11.4.2.8 Date and time of each spiked flue gas sample;

11.4.2.9 Date and time of each unspiked flue gas sample;

11.4.2.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.2.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of Performance Specification 15 (ppm);

11.4.2.12 Bias at the spike level as calculated using equation 3 in section 12.1 of Performance Specification 15; and

11.4.2.13 The correction factor (CF), calculated using equation 6 in section 12.1 of Performance Specification 15.

11.4.3 For each RATA of a HCl or HF CEMS, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (i.e., initial or annual RATA);

11.4.3.4 Reason for test;

11.4.3.5 The reference method used;

11.4.3.6 Starting and ending date and time for each test run;

11.4.3.7 Units of measure;

11.4.3.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.3.9 Flags to indicate which test runs were used in the calculations;

11.4.3.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.3.11 Standard deviation, as specified in Equation 2–4 of Performance Specification 2 in appendix B to part 60 of this chapter;

11.4.3.12 Confidence coefficient, as specified in Equation 2–5 of Performance Specification 2 in appendix B to part 60 of this chapter; and

11.4.3.13 Relative accuracy calculated using Equation 2–6 of Performance Specification 2 in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in section 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

11.4.4 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.9.3 of this appendix.

11.5 *Quarterly Reports.*

11.5.1 Beginning with the report for the calendar quarter in which the initial compliance demonstration is completed or the calendar quarter containing the applicable date in § 63.10005(g), (h), or (j) (whichever is earlier), the owner or operator of any affected unit shall use the ECMPS Client Tool to submit electronic quarterly reports to the Administrator, in an XML format specified by the Administrator, for each affected unit (or group of units monitored at a common stack).

11.5.2 The electronic reports must be submitted within 30 days following the end of each calendar quarter, except for units that have been placed in long-term cold storage.

11.5.3 Each electronic quarterly report shall include the following information:

11.5.3.1 The date of report generation;

11.5.3.2 Facility identification information;

11.5.3.3 The information in sections 10.1.2 through 10.1.7 of this appendix, as applicable to the type(s) of monitoring system(s) used to measure the pollutant concentrations and other necessary parameters.

11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests) of the HCl or HF monitor as described in section 10.1.8.1.1 of this appendix; and

11.5.3.5 If applicable, the results of all daily flow monitor interference checks, in accordance with section 10.1.8.2 of this appendix.

11.5.4 *Compliance Certification.* Based on reasonable inquiry of those persons with primary responsibility for ensuring that all HCl and/or HF emissions from the affected unit(s) have been correctly and fully monitored, the owner or operator shall submit a compliance certification in support of each electronic quarterly emissions monitoring report. The compliance certification shall include a statement by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete.

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