minimize litigation, eliminate ambiguity, and reduce burden.

10. Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

11. Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

12. Energy Effects

This action is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA)(42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves establishing a safety zone for a fireworks display launch site and fallout area and is expected to have no impact on the water or environment. This zone is designed to protect mariners and spectators from the hazards associated with aerial fireworks displays. This rule is categorically excluded from further review under paragraph 34 (g) of Figure 2–1 of the Commandant Instruction. An environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. We seek any comments or information that may lead to the discovery of a significant environmental impact from this rule.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, and Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add temporary § 165.T05–0259 to read as follows:

§ 165.T05–0259 Safety Zone; Pasquotank River; Elizabeth City, NC.

(a) *Definitions.* For the purposes of this section, Captain of the Port means the Commander, Sector North Carolina.

Representative means any Coast Guard commissioned, warrant, or petty officer who has been authorized to act on the behalf of the Captain of the Port.

(b) *Location.* The following area is a safety zone: Specified waters of the Captain of the Port, Sector North Carolina, as defined in 33 CFR 3.25–20, all waters of the Pasquotank River within a 300 yard radius of the fireworks launch barge in approximate position latitude 36°17′47″ N longitude 076°12′17″, located near Machelhe Island.

(c) *Regulations.* (1) The general regulations contained in § 165.23 of this part apply to the area described in paragraph (b) of this section.

(2) Persons or vessels requiring entry into or passage through any portion of the safety zone must first request authorization from the Captain of the Port, or a designated representative, unless the Captain of the Port previously announced via Marine Safety Radio Broadcast on VHF Marine Band Radio channel 22 (157.1 MHz) that this regulation will not be enforced in that portion of the safety zone. The Captain of the Port can be contacted at telephone number (910) 343–3882 or by radio on VHF Marine Band Radio, channels 13 and 16.

(d) *Enforcement.* The U.S. Coast Guard may be assisted in the patrol and enforcement of the zone by Federal, State, and local agencies.

(e) *Enforcement period.* This section will be enforced on May 18, 2013 from 8 p.m. to 11 p.m. unless cancelled earlier by the Captain of the Port.

Dated: April 12, 2013.

A. Popiel,

Captain, U.S. Coast Guard, Captain of the Sector North Carolina.

[FR Doc. 2013–09609 Filed 4–23–13; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044; FRL–9789–5]

RIN 2060–AR62

Reconsideration of Certain New Source Issues: 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; notice of final action on reconsideration.

SUMMARY: The EPA is taking final action on its reconsideration of certain issues in the final rules titled, ''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.'' The National Emission Standards for Hazardous Air Pollutants (NESHAP) rule issued pursuant to Clean Air Act (CAA) section 112 is referred to as the Mercury and Air Toxics Standards (MATS) NESHAP, and the New Source Performance Standards rule issued pursuant to CAA section 111 is referred to as the Utility NSPS. The Administrator received petitions for reconsideration of certain aspects of the MATS NESHAP and the Utility NSPS.

On November 30, 2012, the EPA granted reconsideration of, proposed, and requested comment on a limited set of issues. We also proposed certain technical corrections to both the MATS NESHAP and the Utility NSPS. The EPA is now taking final action on the revised new source numerical standards in the MATS NESHAP and the definitional and monitoring provisions in the Utility NSPS that were addressed in the

proposed reconsideration rule. As part of this action, the EPA is also making certain technical corrections to both the MATS NESHAP and the Utility NSPS. The EPA is not taking final action on requirements applicable during periods of startup and shutdown in the MATS NESHAP or on startup and shutdown provisions related to the PM standard in the Utility NSPS.

DATES: The effective date of the rule is April 24, 2013.

Docket. The EPA established two dockets for this action: Docket ID EPA–HQ–OAR–2011–0044 (NSPS action) and Docket ID EPA–HQ–OAR–2009–0234 (MATS NESHAP action). All documents in the dockets are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (e.g., confidential business information (CBI) or other information whose disclosure is restricted by statute). Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room 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) 566–1742.

FOR FURTHER INFORMATION CONTACT: For the MATS 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:

Outline. The information presented in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

Categories and entities potentially affected by today's action include:

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 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 to provide a guide for readers regarding entities likely to be affected by this action. To determine whether your facility, company, business, organization, etc. would 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 63.9982. 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. How do I obtain a copy of this document?

In addition to being available in the docket, electronic copies of these final rules will be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, 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 the 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 June 24, 2013. 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 can be raised during judicial review. 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 the EPA to enforce these requirements.

II. Background

The final MATS NESHAP and the Utility NSPS rules were published in the **Federal Register** at 77 FR 9304 on

February 16, 2012. Following promulgation of the final rules, the Administrator received petitions for reconsideration of numerous provisions of both the MATS NESHAP and the Utility NSPS pursuant to CAA section 307(d)(7)(B). Copies of the MATS NESHAP petitions are provided in rulemaking docket EPA–HQ–OAR–2009–0234. Copies of the Utility NSPS petitions are provided in rulemaking docket EPA–HQ–OAR–2011–0044. On November 30, 2012, the proposal granting reconsideration of certain issues in the MATS NESHAP and Utility NSPS was published in the **Federal Register** at 77 FR 71323.

III. Summary of Today's Action

This final action amends certain provisions of the final rule issued by the EPA on February 16, 2012. Through an August 2, 2012, notice (77 FR 45967), the EPA delayed the effective date of the February 2012 MATS rule for new sources only. That stay was limited to 90 days and has since expired. The February 2012 final rule is and remains in effect for all sources.

The November 30, 2012, proposed reconsideration rule proposed: (1) Certain revised new source numerical standards in the MATS NESHAP, (2) requirements applicable during periods of startup and shutdown in the MATS NESHAP, (3) startup and shutdown provisions related to the particulate matter (PM) standard in the Utility NSPS, and (4) definitional and monitoring provisions in the Utility NSPS. We also proposed certain technical corrections to both the MATS NESHAP and the Utility NSPS. We are taking final action today on the revised numerical new source MATS NESHAP limits, the definitional and monitoring issues in the Utility NSPS, and all of the technical corrections not related to startup/shutdown issues.

This summary of the final rule reflects the changes to 40 CFR Part 63, subpart UUUUU, and 40 CFR Part 60, subpart Da (77 FR 9304; February 16, 2012) made in this regard.

As noted above, in the proposed reconsideration rule, the EPA took comment on the requirements in the MATS NESHAP applicable during startup and shutdown, including the definitions of startup and shutdown. The EPA also took comment on the startup and shutdown provisions relating to the PM standard in the Utility NSPS. The EPA received considerable comments regarding these startup and shutdown provisions, including data and information relevant to the proposed work practice standard that applies in such periods. The EPA is not taking final action on the startup and shutdown provisions at this time as it needs additional time to consider and evaluate the comments and data provided.[1] The Agency is currently reviewing all of the comments received on the startup and shutdown issues and intends to act promptly to address these issues. We note that no existing sources will have to comply with the existing source MATS standards before April 16, 2015. Further, no new sources are currently under construction and it takes years to complete construction. 77 FR 71330, fn. 7. As such, there will be sufficient time for the Agency to review the comments submitted concerning the proposed startup and shutdown provisions and take appropriate action well in advance of any new source being subject to those provisions.

As described below, on the basis of information provided since the reconsideration proposal, today's action revises certain new source numerical limits in the MATS NESHAP. Specifically, the EPA is finalizing revised hydrogen chloride (HCl), filterable PM (fPM),[2] sulfur dioxide (SO_2), lead (Pb), and selenium emission limits for all new coal-fired EGUs; the mercury (Hg) emission limit for the ''unit designed for coal ≥ 8,300 Btu/lb subcategory;'' fPM and SO_2 emission limits for new solid oil-derived fuel-fired EGUs; fPM emission limits for new continental liquid oil-fired EGUs; and most of the emission limits for new integrated gasification combined cycle (IGCC) units.

The fPM, HCl, and Hg limits that we are finalizing in this action are provided in table 1; the alternate limits that we are finalizing are provided in table 2.[3]

TABLE 1—REVISED EMISSION LIMITATIONS FOR NEW EGUS

Subcategory	Filterable particulate matter, lb/MWh	Hydrogen chloride, lb/MWh	Mercury, lb/GWh
New—Unit not designed for low rank virgin coal	9.0E–2	1.0E–2 [a]	3.0E–3.
New—Unit designed for low rank virgin coal	9.0E–2	1.0E–2 [a]	NR.
New—IGCC	7.0E–2 [b] 9.0E–2 [c]	2.0E–3	3.0E–3.
New—Solid oil-derived	3.0E–2	NR	NR.
New—Liquid oil—continental	3.0E–1	NR	NR.

Note: lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
[a] Beyond-the-floor value.
[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.

TABLE 2—REVISED ALTERNATE EMISSION LIMITATIONS FOR NEW EGUS

Subcategory/pollutant	Coal-fired EGUs	IGCC [a]	Solid oil-derived
SO_2	1.0 lb/MWh	4.0E–1 lb/MWh [b]	1.0 lb/MWh
Total non-mercury metals	NR	4.0E–1 lb/GWh	NR
Antimony, Sb	NR	2.0E–2 lb/GWh	NR
Arsenic, As	NR	2.0E–2 lb/GWh	NR

[1] The EPA is also still reviewing the other issues raised in the petitions for reconsideration and is not taking any action at this time with respect to those issues.

[2] As the final MATS rule established a filterable PM (fPM) limit, every reference in this preamble to a PM limit means filterable PM.

[3] The final rule included certain alternative limits (see 77 FR 9367–9369).

TABLE 2—REVISED ALTERNATE EMISSION LIMITATIONS FOR NEW EGUS—Continued

Subcategory/pollutant	Coal-fired EGUs	IGCC[a]	Solid oil-derived
Beryllium, Be	NR	1.0E–3 lb/GWh	NR
Cadmium, Cd	NR	2.0E–3 lb/GWh	NR
Chromium, Cr	NR	4.0E–2 lb/GWh	NR
Cobalt, Co	NR	4.0E–3 lb/GWh	NR
Lead, Pb	2.0E–2 lb/GWh	9.0E–3 lb/GWh	NR
Mercury, Hg	NA	NA	NR
Manganese, Mn	NR	2.0E–2 lb/GWh	NR
Nickel, Ni	NR	7.0E–2 lb/GWh	NR
Selenium, Se	5.0E–2 lb/GWh	3.0E–1 lb/GWh	NR

NA = not applicable.
NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
[a] Based on best-performing similar source.
[b] Based on DOE information.

In addition, in the MATS NESHAP the EPA is removing quarterly stack testing as an option to demonstrate compliance with the new source fPM emission limits; revising the way in which an owner or operator of a new EGU who chooses to use PM continuous parameter monitoring systems (CPMS) establishes an operating limit; requiring inspections and retesting within 45 days of an exceedance of the operating limit for those new EGU owners or operators who choose to use PM CPMS as a compliance option; and finalizing the presumption of violation of the emissions limit if more than 4 emissions tests are required in a 12-month period.

The final changes to the numerical emissions limits noted above incorporate information about the variability of the best performing EGUs and more accurately reflect the capabilities of emission control equipment for new EGUs. The final changes should also address commenters' concerns that vendors of EGU emission controls had been unwilling to provide guarantees regarding the ability to meet all of the standards for new EGUs as originally finalized in February 2012.

We expect that source owners and operators will install and operate the same or similar control technologies to meet the revised standards in this reconsideration action as they would have chosen to comply with the standards in the February 2012 final rule. Consistent with CAA section 112(a)(4), we are maintaining the new source trigger date for the MATS NESHAP rule as May 3, 2011. See 77 FR 71330, fn. 7. New sources must comply with the revised MATS emission standards described in section IV below by April 24, 2013, or startup, whichever is later.

In the February 2012 final Utility NSPS rule, the EPA adopted a definition of natural gas that excludes coal-derived synthetic natural gas consistent with the definition in MATS. In the Utility NSPS reconsideration proposal, we re-proposed and requested comment on that definition. Based on review of the comments received in response to the reconsideration proposal, the EPA has concluded that the definition of natural gas in the final Utility NSPS is appropriate and, therefore, is not making any changes to that definition. We are also finalizing as proposed one conforming amendment and two amendments related to EGUs burning desulfurized coal-derived synthetic natural gas. First, we amended the definition of coal to make it clear that coal-derived synthetic natural gas is considered to be coal. In addition, in recognition of the fact that emissions from the burning of desulfurized coal-derived synthetic natural gas are very similar to those from the burning of natural gas, we amended the opacity and SO_2 monitoring provisions so that facilities burning desulfurized coal-derived synthetic natural gas will have opacity and SO_2 monitoring requirements similar to those of facilities burning natural gas. Further, we are finalizing certain revisions to the definition of IGCC in the Utility NSPS. We are also finalizing as proposed the revised procedures for calculating PM emission rates intended to make the Utility NSPS procedures consistent with those in the MATS NESHAP. We did not receive any adverse comments regarding this proposed change. Finally, we are finalizing as proposed the technical corrections to the PM standards for facilities that commenced construction before March 1, 2005, and for facilities that commence modification after May 3, 2011.

The impacts of today's revisions on the costs and the benefits of the final rule are minor. As noted above, we expect that source owners and operators will install and operate the same or similar control technologies to meet the revised standards in this action as they would have chosen to comply with the standards in the February 2012 final rule.

IV. Summary of Final Action and Changes Since Proposal—MATS NESHAP New Source Issues

After consideration of the public comments received, the EPA has made certain changes in this final action from the reconsideration proposal. We address the most significant comments in this preamble. However for a complete summary of the comments received on the issues we are finalizing today and our responses thereto, please refer to the memorandum ''National Emission Standards For Hazardous Air Pollutants From Coal- And Oil-Fired Electric Utility Steam Generating Units—Reconsideration; Summary Of Public Comments And Responses'' (March 2013) in rulemaking docket EPA–HQ–OAR–2009–0234.

In this action, we are finalizing certain new source emission limits for the MATS NESHAP, as discussed below.

1. Changes to Certain New Source MATS NESHAP Limits

Commenters noted that in two instances, Pb emissions from coal-fired EGUs and the fPM emissions from continental liquid oil-fired EGUs, the EPA had proposed new source emission limits that were less stringent than those in the final MATS NESHAP for the respective existing sources. This approach was inconsistent with that taken in the final MATS NESHAP.[4] Although CAA section 112(d)(3) allows existing source MACT floor limits to be less stringent than new source limits, the EPA interprets this provision as

[4] See ''*National Emission Standards for Hazardous Air Pollutants (NESHAP) Maximum Achievable Control Technology (MACT) Floor Analysis for Coal- and Oil-fired Electric Utility Steam Generating Units for Final Rule,''* Docket ID EPA–HQ–OAR–2009–0234–20132, p. 13.

precluding new source limits from being less stringent than existing source limits. See CAA section 112(d)(3). Thus, for Pb emissions from coal-fired EGUs and fPM emissions from continental liquid oil-fired EGUs, the EPA is finalizing new source limits that are equivalent to the final existing-source limits.

Next, commenters noted that when evaluating SO_2 emissions data from coal-fired EGUs, the EPA had not selected the lowest emitting source upon which to base the emission limit and that its rationale for excluding certain data was unlawful and arbitrary. Although the EPA disagrees with commenters on several of the excluded data sets (i.e., some of the data sets suggested by commenters comprised only a single 3-run average for each EGU with no individual run data, making assessment of variability impossible), it agrees that it inadvertently omitted the data from Stanton Unit 10 in the proposal analyses. Stanton Unit 10 does have a lower ''lowest'' 3-run data average than does the EGU selected for the new source floor analysis (Sandow Unit 5A) in the proposed reconsideration rule.

In this final action, the EPA used the Stanton data to calculate the MACT floor using the same statistical analyses used in the proposed rule (i.e., 99 percent upper predictive limit (UPL)), and the resulting MACT floor emission limit is 1.3 pounds per megawatt-hour (lb/MWh). Because this limit is less stringent than the new source performance standard (NSPS) finalized in the Utility NSPS (77 FR 9451; February 16, 2012), the EPA is finalizing a beyond-the-floor (BTF) MACT standard of 1.0 lb/MWh, which is the same level required by the CAA section 111 NSPS for these same sources.[5] See 40 CFR 60.43Da(l)(1)(i). Cost is a required consideration in establishing CAA section 111 rules and in going BTF in establishing CAA section 112 rules. We evaluated cost in assessing whether to go BTF for this standard and concluded that it was appropriate to go BTF to a level of 1.0 lb/MWh. Moreover, the NSPS limit (also 1.0 lb/MWh) is in place and coal-fired EGUs are required to comply with that limit. As such, there is no additional cost to these sources.[6] Furthermore, we have not identified any non-air quality health or environmental impacts or energy requirements associated with the final standard set at this level. In addition, in support of the proposed reconsideration rule, we evaluated an emissions level more stringent than 1.0 lb/MWh and found that level to not be cost effective.[7] For these reasons, we are finalizing 1.0 lb/MWh as the new source MATS NESHAP limit.

In the proposed reconsideration rule, we indicated that detection level issues may arise from using a sorbent trap when short sampling periods (e.g., 30 minutes) are used. As such, the EPA solicited comment on its establishment of a Representative Detection Level (RDL) associated with Hg sorbent traps. The EPA also solicited comment on whether the UPL calculated floor should be compared against the 3XRDL value for Hg to account for the shorter sampling periods (the 3XRDL approach). The EPA received several comments, ranging from strong support for the Hg RDL and the proposed emission limit because, at that level, the commenters asserted that vendors would be able to provide commercial guarantees, to concerns about the specific inputs to the 3XRDL calculation and the application of the 3xRDL approach. See section 2.2.1 of the response to comments document (RTC) for a more complete discussion and response to these comments.

In the proposed reconsideration rule, the EPA recognized that 30 minutes of sample collection is the shortest reasonable amount of time available for collecting and changing sorbent tubes to provide the quick, reliable feedback that will allow sources to react to changing Hg emissions levels and assure compliance with the final Hg limit. Some commenters pointed out that the EPA's memorandum entitled ''Determination of Representative Detection Level (RDL) and 3 X RDL Values for Mercury Measured Using Sorbent Trap Technologies,'' [8] contains a 30-minute sample collection time in the 3XRDL calculation, but the text of the memorandum references a 20-minute sample collection time. The EPA has revised the text of the memorandum to reflect its original intent, which was to focus on a sample collection period of 30 minutes (not 20 minutes). The revised memorandum focuses on the 30-minute sample collection period. Given that it takes 5 minutes for sorbent trap insertion and removal, it would take a total of 40 minutes to secure the requisite sample collection (30 minutes for sample collection, 5 minutes to remove the sorbent trap, and 5 minutes to re-insert the trap). We are finalizing the Hg limit using the 3XRDL approach assuming a 30-minute sampling time.

2. Filterable PM Testing, Monitoring, and Compliance

Certification for New EGUs in the MATS NESHAP Rule

Several monitoring options for the fPM standard for new sources were provided in the MATS NESHAP final rule, including quarterly stack testing, PM CEMS, and PM CPMS with annual testing.

The EPA sought comment on whether to retain the quarterly stack testing compliance option for new EGUs, given that continuous, direct measurement of fPM or a correlated parameter is available, is preferable for determining compliance on a continuous basis, and is likely to be used by most new EGUs to monitor compliance with the proposed new source standards. As mentioned above, this final action does not retain the quarterly fPM performance testing option for new EGUs. New EGUs can be designed to incorporate PM CEMS or PM CPMS from the outset, without being impeded by retrofit location installation constraints that could impact existing EGUs. This final action now requires new sources to use either PM CEMS or PM CPMS as options for determining compliance with the new source fPM limits.

The EPA requested comment on a number of issues associated with PM CPMS. The EPA first solicited comment on three approaches to establish an operating limit based on emissions testing for those EGU owners or operators who choose to use PM CPMS as the means of demonstrating compliance with the fPM emission limit. The first approach would require an EGU owner or operator to use the highest parameter value obtained during any run of an individual emissions test as the operating limit when the result of that individual test was below the limit. The second approach would require an EGU owner or operator to use the average parameter value obtained from

[5] The CAA section 111 standard is based on the performance of EGUs with the best performing SO_2 controls, a reasonable incremental cost effectiveness of less than $1,000 per ton of SO_2 controlled, and controls that result in minimal secondary environmental and energy impacts.

[6] The final Utility NSPS limit was not challenged and coal-fired EGUs constructed after May 3, 2011, must meet that limit.

[7] See Docket ID EPA–HQ–OAR–2009–0234–20221 and *National Emission Standards for Hazardous Air Pollutants (NESHAP) Beyond the Maximum Achievable Control Technology (MACT) Floor ('Beyond-the-Floor') Analysis for Revised Emission Standards for New Source Coal-and Oil-fired Electric Utility Steam Generating Units* also in the rulemaking docket.

[8] The EPA developed the memorandum to determine appropriate RDL and 3XRDL values for sorbent trap monitoring systems, as well as calculate an emissions limit, in order to determine the shortest, reasonable sample collection period for those systems. See EPA Docket ID EPA–HQ–OAR–2009–0234–20222.

all runs of an individual emissions test as the operating limit, provided that the result of the individual emissions test met the emissions limit. The third approach, which the EPA is finalizing in this final action, would require an EGU owner or operator to use the higher of the following: (1) A parameter scaled from all values obtained during an individual emissions test to 75 percent of the emissions limit or (2) the average parameter value obtained from all runs of an individual emissions test as the operating limit provided that the result of the individual emissions test met the emissions limit. As established and reaffirmed in the recent Sewage Sludge Incineration, Major Source Industrial Boiler, and Portland Cement rules,[9] it is appropriate to provide increased operational flexibility and reduced emissions testing for sources that emit at or below 75 percent of a standard—whether an emissions or operating limit—as these are the lowest emitting sources. Reduced emissions testing is available in this final rule for those owners or operators whose EGU emissions do not exceed this 75 percent threshold. This 75 percent threshold allows for compliance flexibility and is simultaneously protective of the emission standards. The EPA believes well performing EGUs, i.e., those whose emissions do not exceed 75 percent of the emissions limit, should not face additional scrutiny or testing consequences provided their emissions remain equivalent to or below the 75 percent threshold. In this final action, the EPA uses the 75 percent threshold so as not to impose unintended and costly retest requirements for the lowest emitting sources and to provide for more cost effective, continuous, PM parametric monitoring across the EGU sector. This approach was selected from the options considered as it provides the greatest amount of EGU owner or operator flexibility while demonstrating continuous compliance for EGUs. With this parametric monitoring approach in place, the EPA expects EGUs to evaluate control options that provide excellent fPM emissions control and provide them greater operational flexibility.

Moreover, after each exceedance of the operating limit, the EPA proposed to require emissions testing to verify or re-adjust the operating limit, consistent with the approach contained in the recently-promulgated Portland cement MACT standard (see 78 FR 10014). One commenter objected to potential frequent emissions testing to reassess the operating limit and then being subject to a violation of the emissions limit. The EPA does not believe that too-frequent testing will be required. As discussed in section 4.3.5 of the RTC, the EPA believes well-designed emissions testing will provide an operating limit corresponding with EGU operation, and such testing should yield an operating limit that would not be expected to be exceeded during the course of EGU operation. Therefore, an operating limit developed from well-designed emissions testing should have little, if any, need for frequent reassessment via emissions testing more frequently than the mandated annual reassessment because the source will be able to meet the limit on an ongoing basis.

Finally, the EPA proposed that PM CPMS exceedances leading to more than 4 required emissions tests in a 12-month period (rolling monthly) would be presumed (subject to the possibility of rebuttal by the EGU owner or operator) to be a violation of the emissions limit, consistent with the approach contained in the newly-promulgated Portland cement MACT standard (see 78 FR 10014). The EPA received a number of comments on this proposed provision, including comments supporting and opposing the establishment of such a presumption.

The EPA disagrees with those comments opposing the presumptive violation, and believes the presumptive violation provision in the final rule is a reasonable and appropriate approach to ensure compliance with the standard. First, the EPA may permissibly establish such an approach by rule, assuming there is a reasonable factual basis to do so. See *Hazardous Waste Treatment Council* v. *EPA,* 886 F. 2d 355, 367–68 (DC Cir. 1989) (explaining that such presumptions can legitimately establish the elements of the EPA's *prima facie* case in an enforcement action). Second, there is a reasonable basis here for the presumption that four exceedances (i.e., increases over the parametric operating limit) in a calendar year are a violation of the emission standard. The parametric monitoring limit is established as a 30-day average of the averaged test value in the performance test, or the 75th percentile value if that is higher. In either instance, the 30-day averaging feature provides significant leeway to the EGU owner or operator not to deviate from the parametric operating level because the impact of transient peaks or valleys is limited due to the length of the rule's averaging period—30 boiler operating days, rolled daily. See 77 FR 42377/2 and sources there cited. See also 78 FR 10015, 10019; February, 12, 2013 (Portland Cement MACT) and the RTC for today's action.

The EPA also received comments addressing the re-testing requirements following an exceedance. Some commenters expressed concern about the burden of requiring sources to conduct performance tests in order to demonstrate compliance and to reassess the parameter level. In contrast, other commenters supported a requirement to require re-testing but claimed that the time period between observing a parameter exceedance and retesting is too long. The EPA believes that the re-testing requirements are reasonable and appropriate to identify non-compliance without imposing undue burden. For even a single exceedance to occur, the 30-day average would have to be higher than the operating limit established for the PM CPMS during normal EGU operation. If that occurs, then the EGU owner or operator is required to conduct an inspection to determine any abnormalities and an emissions test to re-establish or generate a new operating limit. Given that EGUs and their emissions control devices are designed to operate at known, specific conditions, deviations from these conditions are not expected and are indicative of problems with load, controls, or some combination of both. Where these sorts of problems result in an exceedance of the source's operating limit, it is reasonable to require re-testing in order to identify and then correct problems. More than four such exceedances of the 30-day average would mean that the EGU owner or operator was unable to determine or correct the problem, since inspection and re-calculation of the operating limit is required after each exceedance. This indicates an ongoing problem with maintaining process control and/or control device operation, which would be the basis for a presumptive violation of the emissions standard. Moreover, the EPA disagrees that the period between exceedance of the operating limit and retesting is too long and could result in possible excessive emissions. Specifically, some commenters claimed that the final rule should not limit the number of exceedances of the PM CPMS limit that require follow-up performance tests in any 12-month period. These commenters alleged that to do so does

[9] See *Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units,* 76 FR 15736 (March 21, 2011); *Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters,* 40 CFR 63.7515(b); and *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10014 (February 12, 2013).

not ensure continuous compliance because the time period between an exceedance and testing could be too long, and a source could be exceeding the emission limit during that time period. The EPA believes that the re-testing requirements reflect a reasonable balance between ensuring compliance and limiting unnecessary testing burden on regulated sources. An EGU owner or operator is required to visually inspect the air pollution control device within 48 hours of the exceedance, and corrective action must be taken as soon as possible to return the PM CPMS measurement to within the established value. A performance test is also required within 45 days of the exceedance to determine compliance and verify or re-establish the PM CPMS limit. Thus, the EPA finds it unlikely that there will be long periods of noncompliance with the underlying fPM standard given the inspection and performance testing requirements.

The EPA also received comments stating that an EGU owner or operator should not be labeled a ''violator'' of the fPM standard as a result of a fourth compliance test in a 12-month period. First, the EPA notes that the rule identifies more than 4 compliance tests over a 12-month period as only a presumptive violation of the emissions limit. A presumption of a violation is just that—a presumption—and can be rebutted in any particular case.

Moreover, in determining whether the presumption has been successfully rebutted, a Court may consider relevant information such as data or other information showing that the EGU's operating process remained in control during the period of operating parameter exceedance, that the ongoing operation and maintenance conducted on the EGU ensured its emissions control devices remained in proper operating condition during the period of operating parameter exceedance, and that results of emissions tests conducted while replicating the conditions observed during the period of operating parameter exceedance remained below the emission limit.

For the reasons explained above, this final action includes the presumption of violation of the emissions limit if more than 4 emissions tests are required in a 12-month period.

V. Summary of Final Action and Changes Since Proposal—Utility NSPS

The EPA has made a number of changes from the reconsideration proposal in this final action after consideration of the public comments received. Most of the changes to the Utility NSPS clarify applicability and implementation issues raised by the commenters. The public comments received on the matters proposed for reconsideration and the responses to them can be viewed in the memorandum ''Summary of EGU NSPS Public Comments and Responses on Amendments Proposed November 30, 2012 (77 FR 71323)'' in rulemaking docket EPA–HQ–OAR–2011–0044.

In the proposed reconsideration rule, the EPA proposed a new definition for IGCC which would be consistent with the MATS NESHAP definition. However, as an alternative we requested comment on whether to retain a definition similar, but not identical, to the IGCC definition in the February 2012 final Utility NSPS. We have concluded that the alternative approach is most appropriate and are adopting a slightly revised definition that is consistent with the Agency's statements on IGCC contained in the RTC in support of the final Utility NSPS rule published on February 16, 2012 (77 FR 9304). Commenters generally supported amending the final Utility NSPS definition of IGCC, and this final action amends that definition consistent with the statements made in the RTC for the Utility NSPS. The Utility NSPS IGCC definition deals with the intent of an IGCC facility and is, thus, broader than the definition in the MATS NESHAP. The facility would still be subject to the same criteria pollutant emission standards even when burning natural gas for extended periods of time. The MATS NESHAP applicability is determined based on the EGU's utilization of coal and oil and the rule may not apply depending on the extent of natural gas usage.

The EPA proposed that the NSPS PM monitoring procedures be consistent with the MATS NESHAP requirements and included the use of quarterly stack testing, PM CPMS, or PM CEMS. In addition, the EPA sought comment on whether to include the quarterly stack testing compliance option for new EGUs, given that continuous, direct measurement of PM or a correlated parameter is available. EGUs complying with an output-based emissions standard can be designed to incorporate PM CEMS or PM CPMS from the outset, without being impeded by retrofit location installation constraints that would impact existing EGUs. This final action requires EGUs complying with an output-based standard to use either PM CEMS or PM CPMS as options for determining compliance with the PM limits. Therefore, the EPA is finalizing the same monitoring procedures for PM for the Utility NSPS as for new sources subject to the MATS NESHAP, and is not finalizing the quarterly stack testing option.

The EPA proposed that facilities using PM CPMS would be able to use either a continuous opacity monitoring system or a periodic alternate monitoring approach to monitor opacity. This final action does not require facilities using a PM CPMS to conduct opacity monitoring. The EPA has concluded that the use of a PM CPMS at the level of the emissions standard required in subpart Da is sufficient to demonstrate compliance with the opacity standard and that additional monitoring is an unnecessary burden.

VI. Technical Corrections and Clarifications

On April 19, 2012 (77 FR 23399), the EPA issued a technical corrections notice addressing certain corrections to the February 16, 2012 (77 FR 9304), MATS NESHAP and Utility NSPS. In the November 30, 2012, reconsideration proposal, we proposed several additional technical corrections. Specific to the NSPS, we proposed correcting the PM standard for facilities that commenced construction before March 1, 2005, to remove the extra significant digit that was inadvertently added and to correct the PM standard for facilities that commence modification after May 3, 2011, to be consistent with the original intent as expressed in the RTC of the final rule published on February 16, 2012 (77 FR 9304). We did not receive any negative comments on these issues and are finalizing them as proposed. Specific details are included in Table 3.

Specific to the MATS NESHAP, the EPA requested comment on whether the proposed technical corrections in Table 4 of the preamble provide the intended accuracy, clarity, and consistency. As mentioned in section 6.3 of the RTC, commenters supported the proposed changes on equations 2a and 3a and this final action contains those changes. As mentioned in section 6.3 of the RTC, commenters did not support the change from a 30 to 60-day notification period for performance testing, and that change was not made to the rule; however, a change to the General Provisions applicability table was made to provide a consistent 30-day notification period. Commenters suggested changes to certain definitions to make them more consistent with the Acid Rain rule provisions, but, as described in section 6.4 of the RTC, these rule changes were not made. These amendments are now being finalized to correct inaccuracies and other inadvertent errors in the final rule and to make the rule language consistent with provisions addressed through this reconsideration.

The final technical changes are described in tables 3 and 4 of this preamble.

TABLE 3—MISCELLANEOUS TECHNICAL CORRECTIONS TO 40 CFR PART 60, SUBPART DA

Section of subpart Da	Description of correction
40 CFR 60.42Da(a)	Correct the erroneous "0.030" to the correct "0.03".
40 CFR 60.42Da(e)(1)(ii)	Correct the erroneous conversion "13 ng/J (0.015 lb/MMBtu)" to the correct "6.4 ng/J (0.015 lb/MMBtu)" by amending the regulatory text to specify that the requirements in 40 CFR 60.42Da(c) or (d), which includes two additional alternative limits, are available compliance alternatives for modified facilities.

TABLE 4—MISCELLANEOUS TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART UUUUU

Section of subpart UUUUU	Description of correction
40 CFR 63.9982(a)	Clarify the language to use the word "or" instead of "and."
40 CFR 63.9982(b) and (c)	Correct the discrepancy between 63.9982(b) and (c) and 63.9985(a).
40 CFR 63.10005(d)(2)(ii)	Correct the typographical error by replacing the incorrect "corresponding" with the correct "corresponds."
40 CFR 63.10005(i)(4)(ii) and (i)(5) and add 63.10005(i)(6).	Revise to clarify the determination and measurement of fuel moisture content.
40 CFR 63.10006(c)	Correct the omission of solid oil-derived fuel- and coal-fired EGUs and IGCC EGUs and the omission of section 10000(c).
40 CFR 63.10007(c)	Correct the omission of section 63.10023 from the list of sections to be followed in establishing an operating limit.
40 CFR 63.10009(b)(2)	Correct omission of the term "boiler operating" and clarify the term "Rt_i" in Equation 2a.
40 CFR 63.10009(b)(3)	Correct omission of the term "system" and clarify the term "Rt_i" in Equation 3a.
40 CFR 63.10010(j)(1)(i)	Correct the typographical error to use the correct word "your" instead of "you."
40 CFR 63.10030(b), (c), and (d)	Clarify the affected-source language.
	Change the period by which a Notification of Intent to conduct a performance test must be submitted to conform to the General Provisions.
40 CFR Section 63.10042	Correct the typographical error in the intended definition of "unit designed for coal ≥ 8,300 Btu/lb subcategory" by replacing the erroneous ">" with the correct "≥."
Table 5 to Subpart UUUUU of Part 63.	Correct the typographical error in footnote 4 by replacing the erroneous "≥" with the correct "≤."
Table 7 to Subpart UUUUU of Part 63.	Clarify the applicability of the alternate 90-day average for Hg in item 1.
	Revise item 3 in the table to clarify use of CMS for liquid oil-fired EGUs.
Table 9 to Subpart UUUUU of Part 63.	Revise to clarify the period for notification of conducting a performance test from 60 to 30 days.
Section 4.1 to Appendix A to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the incorrect citation to "§ 63.10005(g)" with the correct "§ 63.9984(f)."
Section 5.2.2.2 to Appendix A to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the incorrect citation to "Table A–4" with the correct "Table A–2"
Section 3.1.2.1.3 to Appendix B to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the erroneous "≥" with the correct "≤."
Section 5.3.4 to Appendix B to Subpart UUUUU of Part 63.	Correct the section number from the incorrect "5.3.4" to the correct "5.3.3."

VII. Impacts of This Final Rule

A. Summary of Emissions Impacts, Costs and Benefits

Our analysis shows that new EGUs would choose to install and operate the same or similar air pollution control technologies in order to meet the revised emission limits as would have been necessary to meet the previously finalized standards. We project that this final action will result in no significant change in costs, emission reductions, or benefits.[10] Even if there were changes in costs for these EGUs, such changes would likely be small relative to both the overall costs of the individual projects and the overall costs and benefits of the final rule. Further, we believe that EGUs would put on the same controls for this final action that they would have for the original final MATS rule, so there should not be any incremental costs related to this revision.

B. What are the air impacts?

We believe that electric power companies will install the same or similar control technologies to comply with the final standards in this action as they would have installed to comply with the previously finalized MATS standards. Accordingly, we believe that this final action will not result in significant changes in emissions of any of the regulated pollutants.

C. What are the energy impacts?

This final action is not anticipated to have an effect on the supply, distribution, or use of energy. As previously stated, we believe that electric power companies would install the same or similar control technologies as they would have installed to comply with the previously finalized MATS standards.

D. What are the compliance costs?

We believe there will be no significant change in compliance costs as a result of this final action because electric

[10] See *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards [EPA–452/R–11–011]* (docket entry EPA–HQ–OAR–2009–0234–20131) and *Economic Impact Analysis for the Final Reconsideration of the Mercury and Air Toxics Standards* in rulemaking docket EPA–HQ–OAR–2009–0234. As noted earlier, because on an individual EGU-by-EGU basis we anticipate very similar costs, any changes to the baseline since we finalized MATS (e.g., potential impacts of the CSAPR decision) would not impact this determination.

power companies would install the same or similar control technologies as they would have installed to comply with the previously finalized MATS standards. Moreover, we find no additional monitoring costs are necessary to comply with this final action; however, as in any other rule, EGU owners or operators may choose to conduct additional monitoring (and incur its expense) for their own purposes.

E. What are the economic and employment impacts?

Because we expect that electric power companies would install the same or similar control technologies to meet the standards finalized in this action as they would have chosen to comply with the previously finalized MATS standards, we do not anticipate that this final action will result in significant changes in emissions, energy impacts, costs, benefits, or economic impacts. Likewise, we believe this action will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.

F. What are the benefits of the final standards?

As previously stated, the EPA anticipates the power sector will not incur significant compliance costs or savings as a result of this action and we do not anticipate any significant emission changes resulting from this action. Therefore, there are no direct monetized benefits or disbenefits associated with this action.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order (EO) 12866 (58 FR 51735; October 4, 1993), this action is a ''significant regulatory action'' because it ''raises novel legal or policy issues.'' Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821; January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the ''Economic Impact Analysis for the Final Reconsideration of the Mercury and Air Toxics Standards'' found in rulemaking docket EPA–HQ–OAR–2009–0234. Because our analysis shows that new electricity generating units would choose to install the same control technology in order to meet the revised emission limits as would have been necessary to meet the previously finalized MATS standards, we project that this action will result in no significant change in costs, emission reductions, or benefits.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. Today's action does not change the information collection requirements previously finalized and, as a result, does not impose any additional burden on industry. However, OMB has previously approved the information collection requirements contained in the existing regulations (see 77 FR 9304) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0567. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act 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 not-for-profit enterprises, and small governmental jurisdictions.

For purposes of assessing the impacts of today's action on small entities, a small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less that 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. Categories and entities potentially regulated by the final rule with applicable NAICS codes are provided in the Supplementary Information section of this action.

According to the SBA size standards for NAICS code 221122 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million MWh.

After considering the economic impacts of today's action on small entities, I certify that the notice will not have a significant economic impact on a substantial number of small entities.

The EPA has determined that none of the small entities will experience a significant impact because the action imposes no additional regulatory requirements on owners or operators of affected sources. We have therefore concluded that today's action will not result in a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. The action imposes no enforceable duty on any State, local, or tribal governments or the private sector. Therefore, this action is not subject to the requirements of UMRA sections 202 or 205.

This action is also not subject to the requirements of UMRA section 203 because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments or impose obligations upon them.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132. None of the affected facilities are owned or operated by state governments, and the requirements discussed in today's notice will not supersede state regulations that are more stringent. Thus, EO 13132 does not apply to today's notice of reconsideration.

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

This action does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in EO 13175. No affected facilities are owned or operated by Indian tribal governments. Thus, EO 13175 does not apply to today's action.

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

This action is not subject to EO 13045 (62 FR 19885; April 23, 1997) because it is not economically significant as defined in EO 12866. The EPA has evaluated the environmental health or safety effects of the final MATS on children. The results of the evaluation are discussed in that final rule (77 FR 9304; February 16, 2012) and are contained in rulemaking docket EPA–HQ–OAR–2009–0234.

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

This action is not a ''significant energy action'' as defined in EO 13211 (66 FR 28355; May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we conclude that today's action is not likely to have any adverse energy effects because it is not expected to impose any additional regulatory requirements on the owners of affected facilities.

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 EPA to use voluntary consensus standards in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impracticable. Voluntary consensus standards are technical standards (e.g., material specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA requires EPA to provide Congress, through the OMB, with explanations when EPA decides not to use available and applicable voluntary consensus standards.

During the development of the final MATS rule, the EPA searched for voluntary consensus standards that might be applicable. The search identified three voluntary consensus standards that were considered practical alternatives to the specified EPA test methods. An assessment of these and other voluntary consensus standards is presented in the preamble to the final MATS rule (77 FR 9441; February 16, 2012). Today's action does not make use of any additional technical standards beyond those cited in the final MATS rule. Therefore, the EPA is not considering the use of any additional voluntary consensus standards for this action.

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. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice 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 United States.

The EPA has determined that this action will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. Our analysis shows that new EGUs would choose to install the same control technology in order to meet the revised emission limits as would have been necessary to meet the previously finalized standard. Under the relevant assumptions, we project that this action will result in no significant change in emission reductions.

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 United States. The EPA will submit a report containing this final action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States 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 not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective April 24, 2013.

List of Subjects in 40 CFR Parts 60 and 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: March 28, 2013.

Bob Perciasepe,

Acting Administrator.

For the reasons discussed in the preamble, 40 CFR parts 60 and 63 are amended to read as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

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

■ 2. Amend § 60.41Da by revising the definitions of ''Coal'' and ''Integrated gasification combined cycle electric utility steam generating unit,'' and by adding the definition of ''Natural gas'' in alphabetical order to read as follows:

§ 60.41Da Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

* * * * *

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, startup and commissioning, shutdown, 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.

* * * * *

■ 3. Amend § 60.42Da by revising paragraphs (a), (b)(2), and (e)(1) 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 (0.03 lb/MMBtu) heat input.

(b) * * *

(2) An owner or operator of an affected facility that combusts only natural gas and/or synthetic natural gas that chemically meets the definition of natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

* * * * *

(e) * * *

(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, the owner or operator shall not cause to be discharged into the atmosphere from that affected facility 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:

(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, the emission limits specified in paragraphs (c) or (d) of this section.

* * * * *

■ 4. Amend § 60.48Da by revising paragraphs (f), (o) introductory text, (o)(1), (o)(2) introductory text, (o)(3) introductory text, (o)(3)(i), and (o)(4) introductory text to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with the applicable daily average PM emissions limit is determined by calculating the arithmetic average of all hourly emission rates each boiler operating day, except for data obtained during startup, shutdown, or malfunction periods. Daily averages must be calculated for boiler operating days that have out-of-control periods totaling no more than 6 hours of unit operation during which the standard applies. For affected facilities for which construction or reconstruction commenced after May 3, 2011, that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in § 60.42Da is determined on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup or shutdown.

* * * * *

(o) Compliance provisions for sources subject to § 60.42Da(c)(2), (d), or (e)(1)(ii). Except as provided for in paragraph (p) of this section, the owner or operator must demonstrate compliance with each applicable emissions limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in § 60.42Da by the applicable date specified in § 60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in § 60.8 using the test methods and procedures in § 60.50Da. The owner or operator of an affected facility that has not operated for 60 consecutive calendar days prior to the date that the subsequent performance test would have been required had the unit been operating is not required to perform the subsequent performance test until 30 calendar days after the next boiler operating day. Requests for additional 30 day extensions shall be granted by the relevant air division or office director of the appropriate Regional Office of the U.S. EPA.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in § 60.42Da using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

* * * * *

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in § 60.42Da using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in § 60.42Da operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the wet scrubber must be maintained and operated.

* * * * *

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in § 60.42Da by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

* * * * *

■ 5. Amend § 60.49Da by:

■ a. Revising paragraphs (a) introductory text;

■ b. Adding paragraph (a)(3)(iv); and

■ c. Revising paragraphs (a)(4), (b) introductory text, and (t).

The revised and added text reads as follows:

§ 60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard in § 60.42Da must monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (4) of this section.

* * * * *

(3) * * *

(iv) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations must be similar, but not necessarily identical, to the requirements in paragraph (a)(3)(iii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS ''Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.'' This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

* * * * *

(4) An owner or operator of an affected facility that is subject to an opacity standard under § 60.42Da 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 and/or liquid fuels (excluding residue oil) where the potential SO_2 emissions rate of each fuel is 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 § 60.51Da(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 must install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where only gaseous and/or liquid fuels (excluding residual oil) where the potential SO_2 emissions rate of each fuel is 26 ng/J (0.060 lb/MMBtu) or less are combusted, as follows:

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limit under § 60.42Da must either install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section or install, calibrate, operate, and maintain a PM CPMS according to the requirements for new facilities specified in subpart UUUUU of part 63 of this chapter. 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.

* * * * *

■ 6. Revise § 60.50Da(f) to read as follows:

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(f) The owner or operator of an electric utility combined cycle gas turbine that does not meet the definition of an IGCC must conduct performance tests for PM, SO_2, and NO_X using the procedures of Method 19 of appendix A–7 of this part. The SO_2 and NO_X emission rates calculations from the gas turbine used in Method 19 of appendix A–7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

* * * * *

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

■ 7. The authority citation for 40 CFR Part 63 continues to read as follows:

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

■ 8. In § 63.9982, revise paragraphs (a) introductory text, (b), and (c) to read as follows:

§ 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, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

* * * * *

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, and if you commence reconstruction after May 3, 2011.

* * * * *

■ 9. In § 63.10000, revise paragraphs (c)(1)(iv) and (c)(2)(ii) to read as follows:

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

* * * * *

(c) * * *

(1) * * *

(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, for an existing EGU, compliance performance testing repeated quarterly.

* * * * *

(c) * * *

(2) * * *

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

* * * * *

■ 10. Amend § 63.10005 by:

■ a. Revising paragraphs (d)(2)(ii), (i)(4)(ii) and (i)(5);

■ b. Adding paragraph (i)(6).

The revised and added text read as follows:

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

* * * * *

(d) * * *

(2) * * *

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test demonstrating compliance with the emission limit with which you choose to comply.

* * * * *

(i) * * *

(4) * * *

(ii) ASTM D4006–11, ''Standard Test Method for Water in Crude Oil by Distillation,'' including Annex A1 and Appendix A1.

* * * * *

(5) Use one of the following methods to obtain fuel moisture samples:

(i) 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

(ii) ASTM D4057–06 (Reapproved 2011), ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products,'' including Annex A1.

(6) 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.

* * * * *

■ 11. In § 63.10006, revise paragraph (c) to read as follows:

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

* * * * *

(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 emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, § 63.10007, and § 63.10000(c), except as otherwise provided in § 63.10021(d)(1).

* * * * *

■ 12. In § 63.10007, revise paragraph (c) to read as follows:

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

* * * * *

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

* * * * *

■ 13. In § 63.10009, revise paragraphs (b)(2) and (b)(3) to read as follows:

§ 63.10009 May I use emissions averaging to comply with this subpart?

* * * * *

(b) * * *

(2) Weighted 30-boiler operating 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 = Total heat input or gross electrical output of unit i for the preceding 30-boiler operating days, 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 ''coal-fired unit not low rank virgin coal'' 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 system 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 = Total heat input or gross electrical output of unit i for the preceding 90-boiler operating days, 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.

* * * * *

■ 14. In § 63.10010, revise paragraph (j)(1)(i) to read as follows:

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

* * * * *

(j) * * *

(1) * * *

(i) Install and certify your HAP metals CEMS according to the procedures and requirements in your 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.

* * * * *

■ 15. Amend § 63.10021 by adding paragraphs (c)(1) and (2) to read as follows:

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

* * * * *

(c) * * *

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

* * * * *

■ 16. In § 63.10023, revise paragraph (b) to read as follows:

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

* * * * *

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) For an existing EGU, determine your operating limit based on the highest 1-hour average PM CPMS output value recorded during the performance test.

(2) For a new EGU, determine your operating limit as follows.

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average (*x*) in milliamps, and the average of your corresponding three PM compliance test runs (*y*), using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \qquad \text{(Eq. 10)}$$

Where:

X_i = the PM CPMS data points for run i of the performance test,
Y_i = the PM emissions value (in lb/MWh) for run i of the performance test, and
n = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

$$R = \frac{\bar{y}}{(\bar{x} - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative PM lb/MWh per milliamp for your PM CPMS,
$\bar{y}$ = the three run average PM lb/MWh,
$\bar{x}$ = the three run average milliamp output from your PM CPMS, and
z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_L = z + \frac{(0.75 \times L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_L = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,
L = your source PM emissions limit in lb/MWh,
z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and
R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \qquad \text{(Eq. 13)}$$

Where:

X_i = the PM CPMS data points for all runs i,
n = the number of data points, and
O_h = your site specific operating limit, in milliamps.

(iii) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

* * * * *

■ 17. In § 63.10030, revise paragraphs (b), (c), and (d) to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(b) As specified in § 63.9(b)(2), if you startup your EGU that is an 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 EGU that is an 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 EGU that is an 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.

* * * * *

■ 18. Amend § 63.10042 by revising the definition of ''Unit designed for coal > 8,300 Btu/lb subcategory'' to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

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.

* * * * *

■ 19. Revise Table 1 to Subpart UUUUU of Part 63 to read as follows:

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUs

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

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).	9.0E–2 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.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh [1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	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.	

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 limit]

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
	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).	3.0E–1 lb/MWh [1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B 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	OR	
	Total HAP metals	7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	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.	

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 limit]

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
	Nickel (Ni)	4.1E0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[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).	3.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross 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 (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.
[4] Duct burners on syngas; gross electric output.
[5] Duct burners on natural gas; gross electric output.

■ 20. Revise Table 4 to Subpart UUUUU of Part 63 to read as follows:

TABLE 4 TO SUBPART UUUUU OF PART 63—OPERATING LIMITS FOR EGUs

[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 for an existing EGU ..	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).
2. PM CPMS for a new EGU	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 21. Revise footnote 4 of Table 5 to Subpart UUUUU of Part 63 to read as follows:

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS

* * * * * * *

[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% ≤ R ≤ 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:

■ 22. Revise Table 6 to Subpart UUUUU of Part 63 to read as follows:

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[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 . . .
1. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an existing EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the 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 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS—Continued

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

■ 23. Revise Table 7 to Subpart UUUUU of Part 63 to read as follows:

TABLE 7 TO SUBPART UUUUU OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

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

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2.	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.

■ 24. Revise Table 9 to Subpart UUUUU of Part 63 to read as follows:

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, except for the 60-day notification prior to conducting a performance test in § 63.9(d); instead use a 30-day notification period per § 63.10030(d).
§ 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.
§ 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.

■ 25. Revise sections 4.1 and 5.2.2.2 to Appendix A to Subpart UUUUU of Part 63 to read as follows:

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

* * * * *

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 § 63.9984(f).

* * * * *

5.2.2.2 The same RATA performance criteria specified in Table A–2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

* * * * *

■ 26. Revise section 3.1.2.1.3 and the heading to section 5.3.4 to Appendix B to Subpart UUUUU of Part 63 to read as follows:

Appendix B to Subpart UUUUU—HCl and HF Monitoring Provisions

* * * * *

3.1.2.1.3 For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≤ R ≤ 130%; and

* * * * *

5.3.3 *Conditional Data Validation*
* * *

* * * * *

[FR Doc. 2013–07859 Filed 4–23–13; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2012–0282; FRL–9384–2]

Azoxystrobin; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes tolerances for residues of azoxystrobin in or on multiple commodities discussed later in this document. Syngenta Crop Protection, LLC requested these tolerances under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective April 24, 2013. Objections and requests for hearings must be received on or before June 24, 2013, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for these actions, identified by docket identification (ID) number EPA–HQ–OPP–2012–0282, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), EPA West Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC 20460–0001. The Public Reading Room 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 OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Erin Malone, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; telephone number: (703) 347–0253; email address: *Malone.Erin@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Printing Office's eCFR site at *http://www.ecfr.gov/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2012–0282 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before June 24, 2013. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2012–0282, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.htm.*

Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

II. Summary of Petitioned-For Tolerance

In the **Federal Register** of April 4, 2012 (77 FR 20336) (FRL–9340–4), EPA issued a document pursuant to FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 1E7945) by Syngenta Crop Protection, LLC, P.O. Box 18300, Greensboro, NC 27419–8300. The petition requested that 40 CFR 180.507 be amended by establishing an import tolerance for residues of the fungicide azoxystrobin, [methyl(E)-2-(2-(6-(2-cyanophenoxy) pyrimidin-4-yloxy)phenyl)-3-methoxyacrylate], and the *Z*-isomer of azoxystrobin, [methyl(*Z*)-2-(2-(6-(2-