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Laricke Blanchard,

Deputy Director for Policy, Pension Benefit Guaranty Corporation.

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044; FRL–9733–2]

RIN 2060–AR62

Reconsideration of Certain New Source and Startup/Shutdown 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: Proposed rules; notice of public hearing.

SUMMARY: On February 16, 2012, pursuant to sections 111 and 112 of the Clean Air Act (CAA), the EPA published 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 CAA section 112 is referred to as the Mercury and Air Toxics Standards (MATS), 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 MATS and the Utility NSPS. In this notice, the EPA is announcing reconsideration of certain new source standards for MATS, the requirements applicable during periods of startup and shutdown for MATS, the startup and shutdown provisions related to the particulate matter (PM) standard in the Utility NSPS, and certain revisions to the definitional and monitoring provisions of the Utility NSPS. We are also proposing certain technical corrections to both MATS and the Utility NSPS.

We seek comment only on the aspects of the final MATS and Utility NSPS rules specifically identified in this notice. We are not opening for reconsideration any other provisions of MATS or the Utility NSPS at this time.

DATES: *Comments.* Comments must be received on or before December 31, 2012. Because of the need to resolve the issues identified in this notice in a timely manner, the EPA does not intend to grant requests for extensions beyond this date.

Public Hearing. If anyone contacts the EPA by December 10, 2012 requesting to speak at a public hearing, the EPA will hold a public hearing on December 18, 2012. If a public hearing is held, it will be held from 9:00 a.m. to 7:00 p.m., Eastern time, in Room 1153 EPA East Hearing room, 1201 Constitution Avenue NW., Washington, DC 20460, (202) 564–1657. For further information on the public hearing and requests to speak, see the **ADDRESSES** section of this preamble.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID. No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP/MATS action), by one of the following methods:

- *http://www.regulations.gov.* Follow the instructions for submitting comments.
- *http://www.epa.gov/oar/docket.html.* Follow the instructions for submitting comments on the EPA Air and Radiation Docket Web Site.
- *Email:* Comments may be sent by electronic mail (email) to *a-and-r-docket@epa.gov,* Attention EPA–HQ–OAR–2011–0044 (NSPS action) or EPA–HQ–OAR–2009–0234 (NESHAP/MATS action).
- *Fax:* Fax your comments to: (202) 566–9744, Docket ID No. EPA–HQ–OAR–2011–0044 (NSPS action) or Docket ID No. EPA–HQ–OAR–2009–0234 (NESHAP/MATS action).
- *Mail:* Send your comments on the NESHAP/MATS action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Docket ID No. EPA–HQ–OAR–2009–0234. Send your comments on the NSPS action to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Docket ID. EPA–HQ–OAR–2011–0044. Please include a total of two copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St. NW., Washington, DC 20503.
- *Hand Delivery or Courier:* Deliver your comments to: EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460. Please include a total of two copies. Such deliveries are only accepted during the Docket's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holiday), and special arrangements should be made for deliveries of boxed information.

Instructions. All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. All comments will be posted without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Public Hearing. If anyone contacts EPA by December 10, 2012 requesting to speak at a public hearing, the EPA will hold a public hearing on December 18, 2012. If a public hearing is held, it will be held from 9:00 a.m. to 7:00 p.m., Eastern time in Room 1153 EPA East Hearing room, 1201 Constitution

Avenue NW., Washington, DC 20460, 202–564–1657. A lunch break is scheduled from 12:00 p.m.–1:00 p.m. Visitors must go through a metal detector, sign in with the security desk, be accompanied by an employee and show identification to enter the building. Contact Pamela Garrett at (919) 541–7966 or at *garrett.pamela@epa.gov* to request a hearing, to determine if a hearing will be held and to register to speak if a hearing is held. If no one contacts the EPA requesting to speak at a public hearing concerning this proposed rule by December 10, 2012, the hearing will be cancelled without further notice. If a hearing is held, the last day to register to present oral testimony in advance will be Friday, December 14, 2012. The public hearing will provide interested parties the opportunity to present data, views, or arguments concerning this notice. The record for this action will remain open for 30 days after the date of the hearing to provide an opportunity for submission of rebuttal and supplementary information. We will also specify the date and time of the public hearings on *http://www.epa.gov/airquality/powerplanttoxics/actions.html* and *http://www.epa.gov/ttn/atw/utility/utilitypg.html.*

Docket. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (e.g., 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 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 reconsideration notice apply to me?

Categories and entities potentially affected by today's notice 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. What should I consider as I prepare my comments to the EPA?

Do not submit information containing CBI to the EPA through *http://www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID EPA–HQ–OAR–2011–0044 (Utility NSPS) or Docket ID EPA–HQ–OAR–2009–0234 (NESHAP/MATS). Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

C. How do I obtain a copy of this document and other related information?

In addition to being available in the docket, electronic copies of these proposed rules will be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of each proposed rule 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.

II. Background

The Administrator signed MATS and the Utility NSPS on December 16, 2011, and the final rules were published in the **Federal Register** at 77 FR 9304, February 16, 2012. Following promulgation of the final rules, the Administrator received petitions for reconsideration of numerous provisions of both MATS and the Utility NSPS pursuant to CAA section 307(d)(7)(B). Copies of the MATS 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.

III. Today's Action

Today, we are granting reconsideration of, proposing, and requesting comment on the following limited set of issues: (1) Certain revised new source standards in MATS, (2) requirements applicable during periods of startup and shutdown in MATS, (3) startup and shutdown provisions related to the PM standard in the Utility NSPS, and (4) definitional and monitoring provisions in the Utility NSPS. We are also proposing certain technical corrections to both MATS and the Utility NSPS.

This notice is limited to the specific issues identified in this notice. We will not respond to any comments addressing any other provisions of MATS or the Utility NSPS.[1]

The impacts of today's proposed revisions on the costs and the benefits of the final rule are minor. We expect that source owners and operators will install and operate the same or similar control technologies to meet the proposed revised standards in this notice as they would have chosen to comply with the standards in the February 2012 final rule.[2]

IV. Discussion of Provisions Subject to Reconsideration—NESHAP/MATS

A. New Source MATS Emission Limits

The EPA received petitions requesting reconsideration of aspects of the new source emission limits in the final MATS rule. We are granting reconsideration of certain new source emission limits, as discussed below, and we invite comment on the proposed provisions in today's notice.

1. Certain New Source Limits—Use of Data in the Record

The EPA received petitions for reconsideration asserting that the Agency did not use all the data in the record from the best performing sources in establishing certain final new source emission limits for coal- and oil-fired electric utility steam generating units (EGUs). Specifically, the petitioners maintained that the EPA did not consider all of the data in the record when establishing emission standards for filterable PM and hydrogen chloride (HCl) applicable to new coal-fired EGUs and for filterable PM applicable to new solid oil-derived fuel-fired EGUs.

In light of petitioners' assertions, we reviewed the available emissions information in the record for all the new source standards. We determined that we did not use all the data in the record in establishing the new source emission limits for filterable PM and HCl applicable to new coal-fired EGUs and for filterable PM applicable to new solid oil-derived fuel-fired EGUs. We also identified a few additional new source limits for which we did not use all of the data in the record when setting the standards in the final rule. We are proposing to revise the sulfur dioxide (SO_2) limit applicable to solid oil-derived fuel-fired EGUs, the filterable PM limit applicable to continental liquid oil-fired EGUs, and the lead and selenium limits applicable to coal-fired EGUs based on consideration of all the data in the record from the best performing sources for the pollutants at issue. We solicit comment on the revised standards. Additional details on the proposed emission limits can be found in the memo ''Reconsideration of the 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, Proposed Rule'' in rulemaking docket EPA–HQ–OAR–2009–0234.

We also solicit comment on possible revisions to the Hg limit applicable to low rank virgin coal-fired EGUs based on additional data in the record. See ''Reconsideration of the 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, Proposed Rule'' in rulemaking docket EPA–HQ–OAR–2009–0234; ''MATS Reconsideration: Beyond-the-Floor Memorandum'' available in rulemaking docket EPA–HQ–OAR–2009–0234.

The proposed revised new source CAA section 112(d) emission standards are presented in tables 1 and 2 of this preamble. The Agency derived these limits by first calculating the floor standards and then assessing whether a more stringent beyond-the-floor standard is appropriate.[3] As explained further below, as to the standards we are proposing to revise, we are proposing a beyond-the-floor standard for HCl for new coal-fired EGUs, but we are not proposing beyond-the-floor standards for the other pollutants and subcategories.

2. SO_2 Limit for New Coal-Fired EGUs—Reliance on Industrial Boiler Emission Data

We are also reconsidering the SO_2 standard for new coal-fired EGUs. The Agency received a petition asserting that the final alternative SO_2 emission limit was developed using, as the best performing source, a unit that is 25 MW in capacity. In order to be classified as an EGU, and thus subject to MATS, a unit must be greater than 25 MW in capacity. A unit that is 25 MW or less is likely an industrial boiler and would be subject to the Industrial-Commercial-Institutional Boiler NESHAP, not MATS.

At the time of the final rule, we believed the unit on which we based the SO_2 standard for new coal-fired EGUs was an EGU. After we received the petition for reconsideration, we re-

[1] The recent decision by the U.S. Court of Appeals for the D.C. Circuit regarding the Cross State Air Pollution Rule (CSAPR) has no impact on the issues being reconsidered in this action.

[2] 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.

[3] CAA section 112(d)(2) requires the EPA to consider whether more stringent beyond-the-floor standards should be established.

examined the record and determined that the unit was, in fact, an industrial boiler and not an EGU.

As an initial matter, nothing in the CAA precludes the EPA from identifying a source in another source category as the best controlled similar source. However, we believe that it is appropriate in this case, where we have considerable data on EGUs, to base the new source standard on the best performing unit that is an EGU. This is also consistent with our intent in the final rule, as we thought the unit we had selected was, in fact, an EGU. For these reasons, we are reconsidering the SO_2 standard for new coal-fired EGUs. We have reviewed the emissions data and identified the best performing EGU upon which to base the proposed SO_2 standard. The proposed limit is presented in table 2 of this preamble. We solicit comment on the revised limit and the methods used to establish this limit.

3. Hg Limit for New Coal-Fired EGUs Designed for Coal ≥ 8300 Btu/lb—Measurement Issues

The EPA is also reconsidering the emission limit for Hg for new coal-fired EGUs in the units designed for the coal ≥ 8300 Btu/lb (non-low rank virgin coal) subcategory. Some petitioners asserted that this limit, as finalized, was too low for emissions to be reliably measured in a manner that would allow sources to operate their control technology in a way that ensures compliance with the standard. Specifically, petitioners maintained that sorbent trap monitoring systems could not provide sufficiently timely Hg data at the new source level for sources to make adjustments to the EGUs and attendant air pollution control devices (ACPDs) to ensure compliance with the standard and that Hg continuous emissions monitoring systems (CEMS) were not capable of measuring Hg at the new source limit. The petitioners indicated that reliable and frequent emission measurements are needed to maintain the operation of Hg control technology at performance levels set in the final rule.

As we explained in the record to the final rule, owners and operators of new EGUs in the non-low rank virgin coal subcategory could use the sorbent trap monitoring systems to demonstrate compliance with the new source Hg standard because of the potential for a longer sample collection period associated with sorbent traps and their inherent lower emissions detection capability.

As described in the final rule, when establishing emission limits for pollutants, we calculated a representative detection limit (RDL) and then compared the UPL-determined emission floor with a value three times the RDL (3 X RDL), and we set the final limit at the higher of the two numbers. We did not follow that procedure for sorbent trap monitoring systems when setting Hg emission limits as we did not believe sorbent trap monitoring systems were constrained by method detection limits, since operators could increase the sample collection time up to 14 days to guarantee collection of a measurable quantity of mercury with appropriate accuracy. We continue to believe that the promulgated Hg limit for the non-low rank virgin coal subcategory is measurable using a sorbent trap monitoring system.

As noted, however, petitioners have indicated that the long sorbent trap sampling times that may be necessary to measure at the final new source level do not allow sufficiently frequent emissions feedback such that a source could take corrective action and avoid violations of the emission limit within the prescribed compliance time.

We understand that Hg emissions can vary over time, and we acknowledge the value of frequent feedback of emission measurements. We also understand that frequent feedback may be desirable and, at times, necessary to optimize the operation of generation or control technology in order to maintain emissions at or below the standard. The sorbent trap monitoring method required in the MATS rule allows sampling for as long as 14 days. In the final rule, we assumed that most sources would leave the sorbent traps in as long as needed—up to 14 days—to ensure they had no measurement issues. Based on the petitions for reconsideration, we understand that sources will most likely use a shorter sampling period, perhaps as short as 30 minutes. The shorter sampling periods will provide more constant feedback on Hg emissions, which will help the source ensure that it is in compliance with the Hg emission limit, for which compliance is determined on a 30-day rolling average.

Given the petitioners' stated need for more frequent Hg emissions information, we re-evaluated whether detection level issues arise when shorter sampling periods, such as 30 minutes, are employed by sorbent trap monitoring systems. Although the shorter sampling period is adequate to provide information needed to optimize the operation of Hg control technology, we believe the reduced sampling period results in a reduced quantity of collected Hg which constrains the sorbent trap monitoring system by a minimum detection limit. For additional information, see ''Determination of Representative Detection Level (RDL) and 3 X RDL Values for Mercury Measured Using Sorbent Trap Technologies'' in rulemaking docket EPA–HQ–OAR–2009–0234. Specifically, we believe detection level issues may arise from using a sorbent trap when short sampling periods (e.g., 30 minutes) are used, and that, as such, the UPL-calculated floor value should be compared against the 3 X RDL value to account for the shorter sampling periods. We solicit comment on this proposed revised approach in light of the information provided by petitioners regarding the need for prompt Hg emissions information.

Our review of the data in the record shows that for reasonable, shorter sampling conditions—30-minute samples obtained at a sampling rate of 0.5 liter per minute—the UPL-determined new source Hg limit is less than the 3 X RDL value. Therefore, we are proposing to set the Hg limit for the non-low rank virgin coal subcategory at the 3 X RDL value.

Although the value of the resulting limit we are proposing today is higher than that in the final rule, we do not expect this change to alter the emission control strategy of a new EGU, as both emission limits result in Hg removal efficiency in excess of 97 percent. However, the proposed change will improve EGU owners' and operators' ability to track emissions and take preemptive actions to ensure compliance. Based on information provided by the petitioners, our experience, and the National Institute of Standards and Technology's recently confirmed capability to certify Hg calibration gas generators down to 0.2 micrograms per cubic meter ($\mu g/m^3$), the proposed change in the Hg limit will also allow the option of using a Hg CEMS for process control and for determining compliance.

Please refer to the memo ''Data and Procedure for Handling Below Detection Level Data in Analyzing Various Pollutant Emissions Databases for MACT and RTR Emissions Limits'' (docket entry EPA–HQ–OAR–2009–0234–20062) for a discussion of the RDL approach generally, and the memo ''Determination of Representative Detection Level (RDL) and 3 X RDL Values for Mercury Measured Using Sorbent Trap Technologies'' (rulemaking docket EPA–HQ–OAR–2009–0234) for a discussion of our approach for establishing an RDL for Hg. The proposed limit is presented in table 1 of this preamble.

4. Limits for New IGCC EGUs—Use of Permit Limits From Unconstructed IGCC EGUs

We are granting reconsideration of the finalized new source integrated gasification combined cycle (IGCC) limits. The EPA used the permit limits from IGCC EGUs that are permitted but not yet constructed as the basis for some of the final new source IGCC emission limits. Some petitioners asserted that the EPA did not use this approach in the notice of proposed rulemaking and that they therefore were deprived of the opportunity to comment on this approach.

Although we indicated that we considered establishing standards based on IGCC permits at proposal, we are granting reconsideration on the new source IGCC limits so that the public has an additional opportunity to comment on the limits and the approach.

Specifically, we request comment on the proposed new source IGCC standards, which are unchanged from the final standards promulgated for these units on February 16, 2012. These proposed new source limits are presented in tables 1 and 2 of this preamble.

5. Beyond-the-Floor Analysis

The MACT floor level of control for new EGUs is based on the emission control that is achieved in practice by the best controlled similar source, as determined by the Agency, of each HAP for the different subcategories. After the EPA establishes MACT floor levels, CAA section 112(d)(2) requires the EPA to consider whether more stringent beyond-the-floor standards should be established. Under that section, the Agency must consider ''the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements'' before it may establish a standard that is based on a beyond-the-floor level of control.

For most of the new source standards addressed in this proposal, we have not identified additional technologies or HAP emission reduction approaches that would achieve HAP reductions greater than the new source floors for the subcategories, other than multiple controls in series (e.g., multiple scrubbers in series or multiple PM controls in series), which we consider to be unreasonable from a cost perspective. We are therefore proposing to adopt the floor level of control for all but one of these standards. We are proposing a beyond-the-floor standard for HCl emissions from coal-fired EGUs. Summaries of the EPA's beyond-the-floor evaluations for the new source standards addressed in this proposal are provided below. Additional detail of these analyses, including a discussion of costs and non-air quality health and environmental impacts, is provided in the ''MATS Reconsideration: Beyond-the-Floor Memorandum'' available in rulemaking docket EPA–HQ–OAR–2009–0234. We request comment on all aspects of our beyond-the-floor analysis. Specifically, we solicit comment on whether there are any control technologies or HAP emission reduction practices that have been demonstrated to achieve HAP reductions at levels lower than the standards proposed in this notice consistently and in a cost-effective manner. Comments should include information on emissions, pollutant control efficiencies, operational reliability, current demonstrated applications, and costs.

a. Beyond-the-floor analysis for PM from coal-fired EGUs. It is commonly accepted that a baghouse fabric filter (FF) is the technology that provides the best level of PM emission reduction for coal-fired EGUs. Newly constructed coal-fired EGUs will be expected to install FFs to meet the new source NESHAP PM limit that we are proposing in this notice and the applicable NSPS limit. We have considered available options that would allow a new source to achieve greater emission reductions than those achieved in practice by the best controlled source. The EPA is aware that some EGUs have installed downstream secondary ''polishing'' PM control devices to provide for incremental PM reductions beyond what is achieved by the primary PM control device. However, those ''polishing'' PM control devices are most often installed for one of two purposes: (1) To augment the control of an underperforming or undersized primary control device or (2) to allow for injection of activated carbon or other powdered sorbent so that the fly ash and the sorbent remain separated for eventual storage, disposal, or re-use. Given that a new coal-fired EGU would have the opportunity to design the primary PM control device to meet the new source emission limit, we can see no justification for including in the design a secondary downstream ''polishing'' PM control device. Such a device would add considerable cost to the project, and the incremental cost-effectiveness would not be reasonable. See ''MATS Reconsideration: Beyond-the-Floor Memorandum'' in rulemaking docket EPA–HQ–OAR–2009–0234.

b. Beyond-the-floor analysis for Hg from new coal-fired EGUs designed for coal $\geq$ 8300 Btu/lb. The proposed new source Hg emission limit for EGUs firing non-low rank virgin coal is based on the use of the 3 X RDL approach. As explained above, there is concern that a lower emission limit could not be reliably measured with sufficient frequency to allow consistent and timely compliance. For this reason, we are not proposing a limit based on a beyond-the-floor level of control, and, instead, we are proposing to establish the standard at the MACT floor level.

c. Beyond-the-floor analysis for SO_2 emissions from coal-fired EGUs. The best performing source for SO_2 emissions from a coal-fired EGU is a circulating fluidized bed combustor (CFB) with limestone injection for SO_2 control and a downstream circulating dry scrubber (CDS) for supplemental SO_2 control. Because the EGU already employs a downstream ''polishing'' SO_2 control device, we do not believe that installation of an additional ''polishing'' control device would result in cost-effective reduction (in $/ton of incremental SO_2 reduction) that would justify setting a beyond-the-floor emission limit. See ''MATS Reconsideration: Beyond-the-Floor Memorandum'' in rulemaking docket EPA–HQ–OAR–2009–0234.

d. Beyond-the-floor analysis for PM from solid oil-derived fuel-fired EGUs. This analysis is very similar to that which was presented earlier for PM emissions from coal-fired EGUs. Given that a new solid oil-derived fuel-fired EGU would have the opportunity to design the primary PM control device to meet the new source emission limit, we can see no justification for including in the design a secondary downstream ''polishing'' PM control device. As with the coal-fired source, such a device would add considerable costs to the project, and the incremental cost-effectiveness would not be reasonable.

e. Beyond-the-floor analysis for SO_2 from solid oil-derived fuel-fired EGUs. The best performing source for SO_2 emissions from solid oil-derived fuel-fired EGUs is a CFB combustor with limestone injection for SO_2 control. Additional SO_2 control, beyond that which is obtained by the best controlled source, may be obtained by installing a downstream SO_2 control device such as a spray drier absorber (SDA) or wet-flue gas desulfurization (wet-FGD) scrubber or, as was the case with the best performing coal-fired unit, a CDS. However, as stated earlier, we believe that, in this case, the installation of additional downstream ''polishing'' control technologies does not result in cost-effective control (in $/ton of incremental SO_2 reduction) that would justify setting a beyond-the-floor emission limit.

f. Beyond-the-floor analysis for PM from continental liquid oil fuel-fired EGUs. The proposed new source filterable PM emission limit for continental liquid oil-fired fuel is based on an EGU which uses an electrostatic precipitator (ESP). Distillate oil-fired facilities do not need add-on PM controls, as their emissions are inherently low, and residual oil-fired units cannot use FFs for PM control due to concerns about bag contamination and fire safety. ESPs are the best filterable PM control technology for liquid oil fuel-fired EGUs. Given that a new continental liquid-oil fuel-fired EGU would have the opportunity to design the primary PM control device to meet the new source emission limit, we can see no justification for including in the design a secondary downstream ''polishing'' PM control device. Such a device would add considerable costs to the project, and the incremental cost-effectiveness would not be reasonable.

g. Beyond-the-floor analysis for HAP emissions from IGCC EGUs. We have no data upon which to assess whether or not technologies exist that can provide additional HAP control beyond the proposed new source emission limits for new IGCC units. Accordingly, we are not proposing to establish beyond-the-floor emission limitations for these pollutants for new IGCC units. We request comment on whether the use of any control technologies or practices have been demonstrated to consistently achieve in a cost-effective manner, emission levels for similar sources that are lower than those proposed for new IGCC sources in this proposal. Comments should include information on emissions, pollutant control efficiencies, operational reliability, current demonstrated applications, and costs.

h. Beyond-the-floor analysis for HCl emissions from coal-fired EGUs. For HCl, the EPA's revised floor analysis for coal units—discussed above—resulted in a revised MACT floor of 2.0E–2 pound per megawatt-hour (lb/MWh). We have estimated that a new coal-fired EGU would need to remove HCl in the range of 81.0 to 96.6 percent (depending upon the initial chlorine (Cl) content of the fuel) in order to meet this revised MACT floor level of control for HCl emissions. We also note that it is reasonable to expect that in most, if not all, cases, advanced FGD control technology (such as a wet-FGD scrubber or a high efficiency SDA) would be required as a result of other federal requirements—specifically a prevention of significant deterioration (PSD) best available control technology (BACT) analysis. More detailed discussion may be found in the memo ''MATS Reconsideration: Control Technology Needed to Meet New Source Limits'' contained in rulemaking docket EPA–HQ–OAR–2009–0234.

A high efficiency SDA is less costly than a wet-FGD, and we think it likely that some new sources will be able to comply with PSD/BACT requirements using that less expensive option.[4] For this reason, we believe that it is reasonable to assume the minimum level of performance for HCl control from a new EGU will be equivalent to that of a well-performing SDA for purposes of the beyond-the-floor analysis. We examined the level of HCl control achieved by those EGUs from the 2010 utility information collection request (ICR) database that were equipped with SDA and we determined that those EGUs achieved HCl control in a range of 90 to 98 percent (coal-to-stack, depending on the coal Cl content).[5]

We, therefore, are proposing to set a beyond-the-floor HCl emission limit for new coal-fired EGUs at 1.0E–2 lb/MWh. We believe that a new EGU firing lower Cl-content coal would need to achieve a minimum of 90 percent control to meet this proposed limit and that a new EGU firing a higher Cl-content coal would need to achieve a minimum of 98 percent control to meet the limit. We believe that this beyond-the-floor emission limit is cost-effective because it does not involve additional cost, as we expect that any new unit will install at least a high efficiency SDA to comply with other CAA requirements.

We also considered a beyond-the-floor emission limit by assuming installation of a wet-FGD scrubber, which generally achieves greater HCl reductions, but at a greater cost, than a high efficiency SDA. We understand that some new coal-fired EGUs will likely be required to install this type of advanced FGD technology for SO_2 control. However, if the EGU is not required to install a wet-FGD scrubber from the PSD BACT determination for SO_2, then the additional costs beyond those for a high efficiency SDA would be attributable to the achievement of additional HCl emission reductions, and the cost-effectiveness would not be reasonable.

6. Proposed New Source Emission Limits

For coal-fired EGUs, the final rule regulates HCl as a surrogate for acid gas HAP, with an alternative equivalent standard for SO_2 as a surrogate for acid gas HAP for coal-fired EGUs with FGD systems installed and operational; filterable PM as a surrogate for non-mercury HAP metals, with total non-mercury HAP metals and individual non-mercury HAP metals as alternative equivalent standards; Hg; and organic HAP. For oil-fired EGUs, the final rule regulates HCl and HF; filterable PM as a surrogate for total HAP metals, with individual HAP metals as alternative equivalent standards; and organic HAP. The filterable PM, HCl, and Hg limits that we are proposing to revise are provided in table 1; the alternate limits that we are proposing to revise are provided in table 2. We are soliciting comment on the revised new source emission limits proposed in this action.[6]

[4] New Source Review (NSR) permit requirements include, among other things, the application of BACT (best available control technology) under PSD. BACT control technology determinations and associated emission limit establishment involve case-by-case analyses and, such analyses take into account site-specific factors such as energy, environmental and economic impacts. For that reason, it is impossible to strictly predict the outcome of such analyses. However, based on recent BACT determinations for SO_2 emissions from coal-fired EGUs, it is reasonable to expect that in most, if not all, cases, flue gas desulfurization control technologies (such as wet-FGD scrubbers or high efficiency spray drier absorbers) would be required (see *http://cfpub.epa.gov/RBLC/*).

[5] Note that the HCl emission levels achieved are very similar for all EGUs. The difference observed in level of control (percentage) is due to the difference in chlorine levels seen in various coals.

[6] Tables 1 and 2 in this preamble set forth the new source limits the Agency is proposing to revise. However, to comply with **Federal Register** guidelines, ''Table 1 to Subpart UUUUU of Part 63—Emission Limits for New or Reconstructed EGUs'' in the regulatory text includes all of the new source limits, including the limits that are not proposed to be revised and are not part of this reconsideration action. The EPA is only accepting comments on the new source limits that are set forth in tables 1 and 2 of this preamble, which are the limits that are the subject of this reconsideration action.

TABLE 1—PROPOSED EMISSION LIMITATIONS FOR NEW EGUS

Subcategory	Filterable particulate matter	Hydrogen chloride	Mercury
New—Unit not designed for low rank virgin coal	9.0E–2 lb/MWh	1.0E–2 lb/MWh [a]	3.0E–3 lb/GWh.
New—Unit designed for low rank virgin coal	9.0E–2 lb/MWh	1.0E–2 lb/MWh [a]	NR.
New—IGCC	7.0E–2 lb/MWh [b] 9.0E–2 lb/MWh [c]	2.0E–3 lb/MWh [d]	3.0E–3 lb/GWh. [e]
New—Solid oil-derived	3.0E–2 lb/MWh	NR	NR.
New—Liquid oil—continental	4.0E–1 lb/MWh	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 revised.
[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.
[d] Based on best-performing similar source.
[e] Based on permit levels in comments received.

TABLE 2—PROPOSED 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.
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	3.0E–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 revised.
[a] Based on best-performing similar source unless otherwise noted.
[b] Based on DOE information.

7. Control Technologies To Meet Proposed New Source Emission Limits

We have evaluated the levels of control that would generally be needed to meet the proposed emission limits for new sources and have compared those to the levels of control needed to meet the new source emission limits in the final MATS rule. We compared the level of control needed by analyzing requirements for a new hypothetical 500 MW facility. The comparison led us to conclude that new EGUs would need to be designed to use the same types of emission control technologies to meet the proposed new source limits as would have been needed to meet the final MATS new source limits. More detailed discussion of this evaluation may be found in the memo ''MATS Reconsideration: Control Technology Needed to Meet New Source Limits'' contained in rulemaking docket EPA–HQ–OAR–2009–0234.

Nothing in the statute requires the EPA to demonstrate that an existing source is able to meet all of the new source limits. Nevertheless, we note that based on our review of the data EPA collected as part of the 2010 ICR process, at least eight existing non-low rank virgin coal-fired EGUs and one low rank virgin coal-fired EGU have reported short-term stack test data that demonstrate that these EGUs have in practice achieved the new source limits proposed in this notice (considering all of their submitted data). Furthermore, for HCl (as well as the SO_2 surrogate) and filterable PM, the new source limits proposed in this notice are consistent with those in several permits for EGUs that have not yet commenced construction. For Hg, the new source limits proposed in this notice are consistent with the levels that a number of control vendors have suggested in their petitions for reconsideration are achievable and capable of being measured with an appropriate level of accuracy.

8. Filterable PM Monitoring

We provided several monitoring options for the filterable PM standard in the final rule, including quarterly stack testing, PM CEMS, and PM continuous parameter monitoring system (PM CPMS) with annual testing. For many reasons, including continued use of already-installed instruments on some EGUs, direct (as opposed to parametric) measurement of the pollutant of concern, and continuous feedback for process control, we believe that many EGU owners or operators will choose to use PM CEMS to monitor the proposed filterable PM limit.

We solicit comment on whether to retain the quarterly stack testing compliance option, as this option may not be necessary because continuous, direct measurement of filterable PM or a correlated parameter is available and likely to be used by most sources to monitor compliance with the revised standard.

With respect to the PM CPMS compliance option for new EGUs, we considered three approaches to establish an operating limit based on emissions testing. The first approach would allow an EGU owner or operator to use the highest parameter value obtained during an individual emissions test when the result of that individual test was below the limit as the operating limit. The second approach would allow an EGU owner or operator to use the average parameter value obtained from all runs pertaining to an individual emissions test as the operating limit. The third approach would allow an EGU owner or operator whose PM emissions as demonstrated during performance testing do not exceed 75 percent of the PM emissions limit to set his PM CPMS operating limit by linearly scaling the average operating value obtained during all the runs to be equivalent to the value at 75 percent of the limit; an EGU owner or operator whose PM emissions as demonstrated during performance testing exceed 75 percent of the PM emissions limit would establish his operating limit as a 30-day rolling average equal to the average PM CPMS values recorded during performance testing. Such an approach would prevent unnecessary retests for EGUs with low PM emissions. See ''75 Percent CPMS Operating Limit Approach—MATS Reconsideration'' in rulemaking docket EPA–HQ–OAR–2009–0234.

Even though this rule proposes the first approach, we solicit comments on the appropriateness of any of the three approaches to establish a PM CPMS operating limit for new EGUs.

In addition, this rule proposes to require emissions testing after each exceedance of the operating limit for new sources. This rule proposes a number of consequences if the PM monitoring parameter is exceeded. First, the EGU owner or operator will have 48 hours to conduct an inspection of the control device(s) and to take action to restore the controls to proper operation, if necessary, and 45 days to conduct a Method 5 compliance test under the same operating conditions to verify ongoing compliance with the filterable PM limit. Within 60 days, the EGU owner or operator will have to complete the emissions sampling, sample analyses, and verification that the EGU is in compliance with its emissions limit, as well as having to determine an operating limit based on the PM CPMS data collected during the performance test. The EGU owner or operator would then compare the recalculated operating limit with the existing operating limit and, as appropriate, adjust the numerical operating limit to reflect compliance performance. Adjustments could include applying the most recently established value or combining the data collected over multiple performance tests to establish a more representative value. The EGU owner or operator would then apply the reverified or adjusted operating limit value from that time forward.

Second, this rule proposes to limit the number of exceedances of the site-specific CPMS limit leading to follow-up performance tests in any 12 month process operating period and that an excess of this number be considered a violation of the standard. This presumption of violation could be rebutted by the EGU owner or operator, but would require more than a Method 5 test as a basis for the rebuttal (e.g., results of physical inspections would also need to be included). This additional information is necessary since a Method 5 test could not be conducted during or immediately following the discovery of exceedances and would not necessarily represent conditions identical to those when the exceedances occurred. The basis for this part of the proposal is that the site-specific CPMS operating limit reflects a 30-day average that should represent an actual emissions level lower than the three test run numerical emissions limit since variability is mitigated over time. Consequently, we believe that there should be few, if any, exceedances from the 30-day parametric limit and there is a reasonable basis for presuming that exceedances that lead to multiple performance tests to represent poor control device performance and to be a violation of the standard. Therefore, this rule proposes that PM CPMS exceedances leading to more than four required performance tests in a 12-month process operating period is presumed to be a violation of this standard, subject to an EGU owner or operator's ability to rebut that presumption about process and control device operations in addition to the Method 5 performance test results. We solicit comment on this proposed revised approach.

B. Eligibility To Be a New Source

The CAA section 112(a)(4) defines a new source as a stationary source ''the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emissions standard applicable to such source.'' The EPA views the new source trigger date (the date EPA ''first proposes regulations'') to be the date EPA first proposes standards under a particular rulemaking record. (74 FR 21158). In this case, EPA first proposed standards for EGUs on May 3, 2011, and although we are proposing revisions to certain new source standards, the rulemaking record remains the same. As such, we are not proposing to revise the trigger date for determining whether a source is a new source. Any source which commenced construction or reconstruction after May 3, 2011 is subject to the new source standards.[7]

Furthermore, it is the EPA's technical judgment that new sources would need to adopt the same or similar emissions control strategies under the amended standards as they would have under the promulgated standards. The revised standards remain stringent and can be met, in our view, using the same or similar control strategies as would have been required to meet the standards in the final rule.

C. Startup and Shutdown Provisions

The EPA received petitions asserting that the public lacked an opportunity to comment on the startup and shutdown provisions in the final MATS. Petitioners also assert that the definitions of ''startup'' and ''shutdown'' in the final MATS and the provisions for work practice standards did not adequately address applicability to certain types of units, fuels considered ''clean,'' and operational limitations for certain EGU types and/or pollution control devices.

We proposed numerical standards for startup and shutdown periods, and in response to comments on the proposed rule we changed those standards in the final MATS to work practice standards. Among other things, the work practice standards required sources to combust clean fuels during startup and shutdown periods and required sources to engage APCDs when coal or oil was fired in the EGU. (See 77 FR 9380–83). We also revised the definitions of ''startup'' and ''shutdown'' after considering comments we received. Although we revised these provisions in response to comments, we are granting reconsideration on this issue to provide an opportunity for comment on the final startup and shutdown standards and those we have revised and propose today. For further discussion of petitioners' concerns and these proposed revisions, please refer to the memo ''Startup and shutdown provisions'' in rulemaking docket EPA–HQ–OAR–2009–0234. Below we summarize the startup and shutdown revisions proposed today.

1. Definitions

We are proposing to revise the definitions of startup and shutdown in this reconsideration notice as set forth in 40 CFR 63.10042. Petitioners asserted that the final rule's definitions of startup and shutdown were not sufficiently clear, should accommodate operation of

[7] We are unaware of any new source that has commenced construction or reconstruction since May 3, 2011.

cogeneration units, and did not accurately reflect startup conditions for all affected units, particularly supercritical units. We have clarified the definitions and added provisions including useful thermal energy.[8] We believe that these changes address petitioners' concerns. For more discussion, please refer to the memo ''Startup and shutdown provisions'' in rulemaking docket EPA–HQ–OAR–2009–0234.

2. Work Practice Standards

We are proposing several revisions to the finalized work practice standards. Petitioners asserted that the final rule's work practice standards should include certain additional fuels as ''clean fuels'' and recognize operating limitations of certain EGU types and APCDs. Specifically, petitioners contend that the list of clean fuels required for use during startup in order to minimize emissions should include synthetic natural gas, syngas, and ultra-low sulfur diesel (ULSD). The EPA has also been informed since the final rule that propane is used to startup some EGUs and has been requested to consider it as a clean fuel. Petitioners additionally contend that the standards need to recognize operating conditions for FBC EGUs that inject limestone for acid gas control, selective non-catalytic reduction systems (SNCRs), selective catalytic reduction systems (SCRs), and other systems.

In this reconsideration notice, we are proposing to add certain synthetic natural gas, syngas, propane, and ULSD to the list of clean fuels. We solicit comment on our understanding of clean fuels for startup and shutdown.

We are also proposing to require EGU source owners and operators, when firing coal, solid oil-derived fuel, or residual oil in the EGU during startup or shutdown, to vent emissions to the main stack(s) and operate all control devices necessary to meet the operating standards that apply at all other times under the final rule (with the exception of limestone injection in FBC EGUs, dry scrubbers, SNCRs, and SCRs). Owners and operators of EGUs are responsible for starting limestone injection in FBC EGUs, dry scrubbers, SNCRs, and SCRs as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source that require operation of those control devices.

Additionally, we are proposing to revise the final rule's work practice requirements to recognize constraints of certain EGUs and APCDs. The proposed revised standards allow limestone injection to start after appropriate temperatures have been attained in FBC EGUs that inject limestone for acid gas control and allow SNCR, SCR, and dry scrubber systems to start as soon as technically feasible after the appropriate temperature has been reached.

For more discussion of each of these issues, please refer to the memo ''Startup and shutdown provisions'' in rulemaking docket EPA–HQ–OAR–2009–0234.

3. Treatment of IGCC EGU Syngas

The EPA understands that at an IGCC EGU, syngas is generated in the gasifier and combusted in the turbine. During the startup and shutdown periods, some or all of the syngas produced may not be combusted in the turbine. We are proposing two options for IGCC EGUs for handling syngas not fired in the combustion turbine: (1) syngas must be flared, not vented or (2) syngas must be routed to duct burners, which may need to be installed, and the flue gas from the duct burners must be routed to the heat recovery steam generator. We are soliciting comments on the need to flare the unfired syngas, if it is more appropriate to require routing of the unfired syngas back into the system for all IGCC EGUs, and on the costs of adding duct burners, should they be required.

We solicit comments on the proposed revisions to the startup and shutdown requirements set forth in this notice.

V. Discussion of Provisions Subject To Reconsideration—Utility NSPS

Petitioners state that because the final Utility NSPS rule contains a definition of ''natural gas'' that was not included in the proposed rule, they were not able to comment on the definition. Further, petitioners maintain that the definition established in the final rule is not a ''logical outgrowth'' of the proposed rule. Although the definition was changed between proposal and final based on public comment, we are re-proposing the definition of natural gas that was in the final Utility NSPS to allow additional opportunity to comment.

We are also proposing several additional amendments so that synthetic natural gas will receive similar treatment as natural gas. We seek comment on all aspects of these additional amendments. First, consistent with the NESHAP definition, we are proposing to clarify the definition of coal to include synthetic natural gas derived from coal. As such, we are also proposing to add synthetic natural gas to the opacity exemption in paragraph 40 CFR 60.42Da(b)(2) since facilities burning synthetic natural gas would otherwise be subject to an opacity standard. In addition, we are also proposing to replace ''natural gas'' with ''gaseous fuels'' in 40 CFR 60.49Da(b) so facilities burning desulfurized coal-derived synthetic natural gas are not required to install an SO_2 CEMS. The proposed amendments to the startup and shutdown requirements in the NESHAP portion of this proposal would also allow the use of synthetic natural gas for the work practice standards required for PM emissions control during periods of startup and shutdown.

Additional proposed amendments include amending the definition of an IGCC to be similar to the corresponding NESHAP MATS definition. Potential language is as follows:

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 burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

We believe that this would address the issue of IGCC facilities switching applicability between the stationary combustion turbine NSPS (40 CFR part 60, subpart KKKK) and the Utility NSPS. However, we are specifically requesting comment if it would be more appropriate to maintain the existing NSPS IGCC definition and add ''startup and commissioning, shutdown'' as suggested by one petitioner. Potential language for the alternate definition is as follows:

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.

In addition, the rationale for the filterable PM standard startup and shutdown work practice provision discussed in the NESHAP portion of this notice also applies to the filterable PM startup and shutdown standards in the Utility NSPS. Therefore, we are proposing to amend both the emissions

[8] 16 U.S.C. 796(18)(A) and 18 CFR 292.202(c).

rate calculation procedure and monitoring requirements for PM to be similar to the requirements specified in the NESHAP for new facilities. Owners/operators of EGUs subject to the Utility NSPS would calculate the filterable PM emissions rate as the average of the measured hourly rates during the applicable averaging period (instead of as the sum of the emissions divided by the sum of the output over the applicable averaging period) and would use either a PM CEMS, PM CPMS, or quarterly performance testing to demonstrate compliance with the applicable standard.[9]

Finally, we are proposing to clarify that owners/operators electing to use PM CPMS to monitor PM emissions are exempt from the requirement to install a continuous opacity monitoring system (COMS) and would be allowed to elect to use alternate opacity monitoring procedures currently allowed in the Utility NSPS.

VI. Technical Corrections and Clarifications

On April 19, 2012 (77 FR 23399), we issued a technical corrections notice addressing certain corrections to the February 16, 2012 (77 FR 9304) MATS.

In this notice, we are proposing several additional technical corrections. These amendments are being proposed to correct inaccuracies and other inadvertent errors in the final rule and to make the rule language consistent with provisions addressed through this reconsideration. We are soliciting comment only on whether the proposed changes provide the intended accuracy, clarity and consistency. These proposed technical changes are described in tables 3 and 4 of this preamble. We request comment on all of these proposed changes.

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

Section of subpart Da	Description of proposed 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 PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART UUUUU

Section of subpart UUUUU	Description of proposed 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 63.10011(g)	Clarify the language to use the word "and" instead of "or" between the words "startup" and "shutdown."
	Clarify the language to use the word "or" instead of "and" between the words "oil-fired" and "solid."
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	Revise the definition of "boiler operating day" to clarify that periods of startup or shutdown are not included.
	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.
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."

[9] As discussed in the final Utility NSPS Response to Comments document, because the amended NO_X and SO_2 standards used CEMS data and included all periods of operation when establishing the numerical values for those standards, we are not proposing to amend how periods of startup and shutdown are handled or how the emission rates are calculated for the Utility NSPS NO_X and SO_2 standards. See docket entry EPA–HQ–OAR–2011–0044–5759, p. 7.

VII. Impacts of This Proposed Rule

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 rule will result in no significant change in costs, emission reductions, or benefits.[10] Even if there were changes in costs for these units, 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, which is dominated by actions taken by existing units. Further, as noted elsewhere in this preamble, we believe that EGUs would put on the same controls for this proposed rule that they would have for the original final, so there should not be any incremental costs related to this proposed revision.

A. What are the air impacts?

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

B. What are the energy impacts?

This proposed rule 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 standards.

C. What are the compliance costs?

We believe there will be no significant change in compliance costs as a result of this proposed rule because electric power companies would install the same or similar control technologies as they would have installed to comply with the previously finalized standards. Moreover, we find no additional monitoring costs are necessary to comply with the proposed rule; however, as in any other rule, EGU owners or operators may choose to conduct additional monitoring (and incur its expense) for their own purposes.

D. 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 proposed in this action as they would have chosen to comply with the previously finalized standards, we do not anticipate that this proposed rule will result in significant changes in emissions, energy impacts, costs, benefits, or economic impacts. Likewise, we believe this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.

E. What are the benefits of the proposed standards?

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

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 (E.O.) 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it ''raises novel legal or policy issues arising out of legal mandates.'' 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 Proposed 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 standard, we project that this rule 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 notice of reconsideration 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 77FR 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 notice of reconsideration 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.

[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 the memo ''Economic Impact Analysis for the Proposed 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.

After considering the economic impacts of today's notice of reconsideration 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 notice of reconsideration imposes no additional regulatory requirements on owners or operators of affected sources. We have therefore concluded that today's notice of reconsideration will not result in a significant economic impact on a substantial number of small entities. We continue to be interested in the potential impacts of the rule on small entities and welcome comments on issues related to such impacts.

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.

In the spirit of EO 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA specifically solicits comment on this notice of reconsideration from state and local officials.

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 notice of reconsideration. The EPA specifically solicits comment on this notice of reconsideration from tribal officials.

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 Mercury and Air Toxics Standards 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.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of early life exposure to hazardous air pollutants.

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 notice of reconsideration 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 rule, 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 rule (77 FR 9441; February 16, 2012). Today's notice of reconsideration does not propose the use of any additional technical standards beyond those cited in the final rule. Therefore, EPA is not considering the use of any additional voluntary consensus standards for this notice.

The EPA welcomes comments on this aspect of this notice of reconsideration and, specifically, invites the public to identify potentially-applicable voluntary consensus standards and to explain why such standards should be used in this regulation.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629 (Feb. 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 notice of reconsideration 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 rule will result in no significant change in emission reductions.

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: November 16, 2012.

Lisa P. Jackson,

Administrator.

For the reasons discussed in the preamble, the EPA proposes to amend 40 CFR parts 60 and 63 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 burns a synthetic natural gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

* * * * *

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), (e)(1) introductory text, and (e)(1)(ii) 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 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.

* * * * *

(ii) For an affected facility which commenced modification, any gases that contain PM in excess of the emission limits specified in paragraphs (c) or (d) of this section.

* * * * *

■ 4. Amend § 60.48Da by revising paragraphs (a), (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.

(a) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, the applicable PM emissions limit and opacity standard under § 60.42Da, SO_2 emissions limit under § 60.43Da, and NO_X emissions limit under § 60.44Da apply at all times except during periods of startup, shutdown, or malfunction. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO_2 emissions limit under § 60.43Da, NO_X emissions limit under § 60.44Da, and NO_X plus CO emissions limit under § 60.45Da apply at all times. The applicable PM emissions limit and opacity standard under § 60.42Da apply at all times except during periods of startup and shutdown; however, you are required to meet the work practice requirements as specified in 60.42Da(e)(2) of this subpart during periods of startup and shutdown.

* * * * *

(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 are only calculated for boiler operating days that have non-out-of-control data for at least 18 hours of unit operation during which the standard applies. Instead, all of the non-out-of-control hourly emission rates of the operating day(s) not meeting the minimum 18 hours non-out-of-control data daily average requirement are averaged with all of the non-out-of-control hourly emission rates of the next boiler operating day with 18 hours or more of non-out-of-control PM CEMS data to determine compliance. For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with the applicable 30-boiler operating day rolling average PM emissions limit is determined 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 shall 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 and (a)(2);

■ b. Adding paragraphs (a)(2)(v) and (a)(3)(iv); and

■ c. Revising paragraphs (a)(4) introductory text, (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 shall 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.

* * * * *

(2) As an alternative to the monitoring requirements in paragraph (a)(1) of this section, an owner or operator of an affected facility that meets the conditions in either paragraph (a)(2)(i), (ii), (iii), (iv), or (v) of this section may elect to monitor opacity as specified in paragraph (a)(3) of this section.

* * * * *

(v) 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.

* * * * *

(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 shall 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 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 exceedances with the excess emissions report required under § 60.51Da(d).

* * * * *

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where 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 shall either install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section, 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, or conduct quarterly testing 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 paragraph (f) to read as follows:

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(f) The owner or operator of an electric utility combined cycle gas turbines that does not meet the definition of an IGCC shall 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, or if you commence reconstruction after May 3, 2011.

* * * * *

■ 9. In § 63.10005, revise paragraphs (d)(2)(ii), (i)(4)(ii), and (i)(5) and add paragraph (i)(6) to 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.

* * * * *

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

* * * * *

■ 11. 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 to comply with the filterable PM emission limit and demonstrate continuous performance using a PM CPMS for an applicable emission limit as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 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.

* * * * *

■ 12. 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.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq. 2b)$$

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.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Rm_i)]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Rm_i)]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq. 3a)$$

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.

$$WAER = \frac{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}[\sum_{i=1}^{n}(Sm_i \times Cfm_i)]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq. 3b)$$

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.

* * * * *

■ 13. 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.

* * * * *

■ 14. In § 63.10011, revise paragraphs (f) and (g) to read as follows:

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

* * * * *

(f) You must use during periods of startup or shutdown any one or combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, synthesis gas (syngas), and ultra-low sulfur diesel (ULSD).

(g) You must follow the startup and shutdown requirements in Table 3 for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU.

■ 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 from 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 based on the highest 1-hour average PM CPMS output value recorded during the performance test.

* * * * *

■ 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 60 days before the performance test is scheduled to begin.

* * * * *

■ 18. Amend § 63.10042 by:

■ a. Revising the definitions of ''Boiler operating day,'' ''Shutdown'', ''Startup'', and ''Unit designed for coal > 8,300 Btu/lb subcategory''; and

■ b. Adding, in alphabetical order, a new definition of ''Clean fuel''.

The revised and added text reads as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Boiler operating day means a 24-hour period that begins at midnight and ends the following midnight during which any fuel is combusted at any time in the EGU, excluding periods of startup or shutdown. It is not necessary for the fuel to be combusted the entire 24-hour period.

* * * * *

Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas (syngas), or ultra-low-sulfur diesel (ULSD).

* * * * *

Shutdown means the period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes or when no coal, liquid oil, syngas, or solid oil-derived fuel is being fired in the EGU, whichever is earlier. Shutdown ends when the EGU no longer generates electricity or makes useful thermal energy (such as steam or heat) for industrial, commercial, heating, or cooling purposes, and no fuel is being fired in the EGU.

Startup means the period in which operation of an EGU is initiated for any purpose. Startup begins with either the first-ever firing of fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes or the firing of fuel in an EGU for any purpose after a shutdown event. Startup ends when the EGU generates electricity that is sold or used for any other purpose (including on site use), or the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier.

* * * * *

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 limits:

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
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.	

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 . . .
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	3.0E–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)	3.0E–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.	
	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).	4.0E–1 lb/MWh[1] OR	Collect a minimum of 1 dscm per run. Collect a minimum of 2 dscm per run.
	OR	2.0E–4 lb/MWh	
	Total HAP metals	OR	
	OR		
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 . . .
	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). OR Total HAP metals OR	2.0E–1 lb/MWh[1] OR 7.0E–3 lb/MWh OR	Collect a minimum of 1 dscm per run. Collect a minimum of 1 dscm per run.
	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.	
	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). OR	3.0E–2 lb/MWh[1] OR	Collect a minimum of 1 dscm per run.
	Total non-Hg HAP metals OR	6.0E–1 lb/GWh OR	Collect a minimum of 1 dscm per run.
	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.

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 . . .
	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 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 3 to Subpart UUUUU of Part 63 to read as follows:

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

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

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during startup.	You must operate all CMS during startup. For startup of an EGU, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, and ultra-low sulfur diesel. Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in FBC EGUs, dry scrubber, SNCR, and SCR. You must start your limestone injection in FBC EGUs, dry scrubber, SNCR, and SCR systems as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control devices. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during startup, you must either: (1) Flare the syngas or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.10020(a). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).
4. A coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC EGUs, dry scrubber, SNCR, and SCR. You must operate your limestone injection in FBC EGUs, dry scrubber, SNCR, and SCR systems as expeditiously as possible, but, in any case, when necessary to comply with other standards that apply to the source and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, distillate oil, syngas, and ultra-low sulfur diesel. Relative to the syngas not fired in the combustion turbine of an IGCC EGU during shutdown, you must either: (1) Flare the syngas or (2) route the syngas to duct burners, which may need to be installed, and route the flue gas from the duct burners to the heat recovery steam generator. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in § 63.10020(a). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.10011(g) and § 63.10021(h) and (i).

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

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

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 at or below the highest 1-hour average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 22. Revise 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:

* * * * *

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

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

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.
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 three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance run demonstrating compliance with the filterable PM or HAP metals emissions limitations.

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

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

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

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit.	Calculating the arithmetic 30- (or 90-) boiler operating day rolling average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30 boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring 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 applicable emissions limit in Table 1 or 2.	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s)	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

■ 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 shall 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. 2012–28729 Filed 11–29–12; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 271 and 272

[EPA–R06–RCRA–2012–0473; FRL–9745–1]

Texas: Final Authorization of State-initiated Changes and Incorporation by Reference of State Hazardous Waste Management Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: During a review of Texas' regulations, the EPA identified a variety of State-initiated changes to its hazardous waste program under the Resource Conservation and Recovery Act (RCRA). We have determined that these changes are minor and satisfy all requirements needed to qualify for Final authorization and are authorizing the State-initiated changes through this Direct Final action.

The Solid Waste Disposal Act, as amended, commonly referred to as the Resource Conservation and Recovery Act (RCRA), allows the Environmental Protection Agency (EPA) to authorize States to operate their hazardous waste management programs in lieu of the Federal program. The EPA uses the regulations entitled ''Approved State Hazardous Waste Management Programs'' to provide notice of the authorization status of State programs and to incorporate by reference those provisions of the State statutes and regulations that will be subject to the EPA's inspection and enforcement. The rule codifies in the regulations the prior approval of Texas' hazardous waste management program and incorporates by reference authorized provisions of the State's statutes and regulations.

DATES: This regulation is effective January 29, 2013, unless the EPA receives adverse written comment on the codification of the Texas authorized RCRA program by the close of business December 31, 2012. If the EPA receives such comments, it will publish a timely withdrawal of this direct final rule in the **Federal Register** informing the public that this rule will not take effect. The incorporation by reference of authorized provisions in the Texas statutes and regulations contained in this rule is approved by the Director of the Federal Register as of January 29, 2013 in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

ADDRESSES: Submit your comments by one of the following methods:

1. *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the on-line instructions for submitting comments.

2. *Email: patterson.alima@epa.gov* or *banks.julia@epa.gov.*

3. *Mail:* Alima Patterson, Region 6, Regional Authorization Coordinator, or Julia Banks, Codification Coordinator, State/Tribal Oversight Section (6PD–O), Multimedia Planning and Permitting Division, EPA Region 6, 1445 Ross Avenue, Dallas, Texas 75202–2733.

4. *Hand Delivery or Courier:* Deliver your comments to Alima Patterson, Region 6, Regional Authorization Coordinator, or Julia Banks, Codification Coordinator, State/Tribal Oversight Section (6PD–O), Multimedia Planning and Permitting Division, EPA Region 6, 1445 Ross Avenue, Dallas, Texas 75202–2733.