ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234 and EPA–HQ–OAR–2011–0044; FRL–9921–04–OAR]

RIN 2060–AS41

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; Revisions

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is proposing this action to correct and clarify certain text of the final action 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,'' which was published in the **Federal Register** of Thursday, February 16, 2012. We are also proposing to remove rule provisions establishing an affirmative defense for malfunction events in light of a recent court decision on the issue.

DATES: *Comments.* Comments must be received on or before April 3, 2015.

Public Hearing. If anyone contacts the EPA requesting a public hearing by February 23, 2015, the EPA will hold a public hearing on March 4, 2015 from 1 p.m. (Eastern Standard Time) to 5 p.m. (Eastern Standard Time) at the U.S. Environmental Protection Agency building located at 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. If the EPA holds a public hearing, the EPA will keep the record of the hearing open for 30 days after completion of the hearing to provide an opportunity for submission of rebuttal and supplementary information.

ADDRESSES: 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:

- *Federal rulemaking portal: http://www.regulations.gov*. Follow the instructions for submitting comments.
- *Agency Web site: 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: 28221T, 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. No. EPA–HQ–OAR–2011–0044.
- *Hand Delivery or Courier:* Deliver your comments to: EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460. 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.

FOR FURTHER INFORMATION CONTACT: For the NESHAP action: Mr. Barrett Parker, Measurement Policy Group, Sector Policies and Programs Division, (D243–05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5635; Fax number (919) 541–3207; email address: *parker.barrett@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:

Comment 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 requested by February 23, 2015, we will hold a public hearing on March 4, 2015, from 1 p.m. (Eastern Standard Time) to 5 p.m. (Eastern Standard Time) at the U.S. Environmental Protection Agency building located at 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Please contact Ms. Pamela Garrett of the Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: 919–541–7966; email address: *garrett.pamela@epa.gov*; to request a hearing, register to speak at the hearing or to inquire as to whether or not a hearing will be held. The last day to pre-register in advance to speak at the hearing will be March 2, 2015. Additionally, requests to speak will be taken the day of the hearing at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. If you require the service of a translator or special accommodations such as audio description, we ask that you pre-register for the hearing, as we may not be able to arrange such accommodations without advance notice. The hearing will provide interested parties the opportunity to present data, views or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. Because this hearing is being held at a U.S. government facility, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. Please note that the REAL ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. If your driver's license is issued by Alaska, American Samoa, Arizona, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Montana, New York, Oklahoma or the State of Washington, you must present an additional form of identification to enter the federal building. Acceptable alternative forms of identification include: Federal employee badges, passports, enhanced driver's licenses and military identification cards. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building and demonstrations will not be allowed on federal property for security reasons. The EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing. Verbatim transcripts of the hearing and written statements will be included in the docket for the rulemaking. The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearing to run either ahead of schedule or behind schedule. Again, a hearing will not be held on this rulemaking unless requested. A hearing needs to be requested by February 23, 2015. Again, please contact Ms. Pamela Garrett of the Sector Policies and Programs Division (D243–01), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number: 919–541–7966; email address: *garrett.pamela@epa.gov* to request a hearing.

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.

I. Technical Corrections

The final Clean Air Act (CAA) rules published in the **Federal Register** on February 16, 2012 (77 FR 9303), establish national emission standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units (EGUs), referred to as ''the Mercury and Air Toxics Standards'' or ''MATS,'' and new source performance standards (NSPS) for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial-institutional steam generating units, referred to as the Utility NSPS.

In this document, the EPA proposes to correct certain regulatory text. The proposed corrections can be categorized generally as follows: (a) Resolution of conflicts between preamble and regulatory text, (b) corrections that we stated we would make in response to comments that were inadvertently not made, and (c) clarification of language in regulatory text. Below, we identify each proposed technical correction to the regulatory text as found in the Code of Federal Regulations (*i.e.,* 40 CFR). The EPA is soliciting comments on all of these proposed corrections.

1. Section 60.49Da(f) is revised to amend the procedures for calculating compliance with the NSPS daily average particulate matter (PM) emission limit for affected facilities using PM continuous emission monitoring systems (CEMS) and that commenced construction, modification, or reconstruction before May 4, 2011. Even though it was not included in the proposal, in an effort to clarify certain language in 40 CFR 60.48Da(f), we amended the procedure for calculating compliance with the daily average PM limit for affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, using PM CEMS (78 FR 24073; April 24, 2013). The amendments removed the provision that for operating days with less than 18 hours of PM CEMS data, the data for that day would be rolled into the following operating day(s) until 18 hours of data are available. The intent of the original language was to assure that compliance with the daily PM emission rate was not determined with significantly less than 24 hours of data, but that all emissions data would still be used. The intent of the revised data was to eliminate the requirement to roll emissions data recorded on days without sufficient data to determine a daily average to the following operating day, but that a minimum of 18 hours would still be required to determine compliance with the daily PM standard. Industry requested reconsideration stating that they did not have an opportunity to comment on the issue, and that the revised calculation procedures could in fact require compliance determinations with significantly less than 24 hours of data. The proposed revisions would undo those changes and return the calculation procedures to the approach used prior to April 24, 2013. Specifically, for operating days with less than 18 hours of PM CEMS data, that data would be rolled into the following operating day(s) until over 18 hours of data are available to determine compliance with the operating day standard. We are soliciting comment on whether the intent of the current calculation procedures should be maintained (*i.e.,* data collected on days with less than 18 hours of data would not be used to determine compliance with the PM standard and would also not be rolled into the following operating day(s)). If the current approach is maintained, the regulatory language would be revised to avoid situations where compliance calculations would be made with less than 18 hours of data.

2. Section 63.9983(a) is revised to clarify that MATS does not apply to either major or area source combustion turbines, except for integrated gasification combined cycle (IGCC) units. In the final MATS rule, 40 CFR 63.9983(a) exempted from MATS ''any unit designated as a stationary combustion turbine, except an integrated gasification combined cycle (IGCC) unit, covered by 40 CFR part 63, subpart YYYY.'' Because area source stationary combustion turbines are not subject to subpart YYYY, which is applicable to stationary combustion turbines located at major sources, the Agency received questions concerning the applicability of MATS to the area

source units in that category. The EPA intended by the exemption to exempt all stationary source combustion turbines other than IGCC units from the requirements of MATS, because the EPA does not interpret the statute to include those units within the definition of EGU in CAA section 112(a)(8). The proposed revisions to the regulations will clarify the EPA's interpretation and intent and prevent future confusion concerning the applicability of the MATS rule to stationary combustion turbines located at area sources.

3. Section 63.9983(b) and (c) is revised consistent with the definitional changes discussed below. The definitional changes are being proposed so that sources will know the time period to consider when determining whether their coal or oil utilization triggers applicability of the MATS rule. As explained below, the change is particularly important in the first 3 years after the compliance date when sources will be required to estimate coal and oil utilization in their EGUs to determine applicability of the MATS rule.

4. Section 63.9983(e) is added to clarify CAA section 112 applicability to the units that meet the definition of a natural gas-fired EGU in MATS, and, because they combust greater than 10 percent biomass, also meet the definition of a biomass-fired boiler in the Industrial Boiler NESHAP (40 CFR part 63, subpart DDDDD). These overlapping definitions led to confusion in the regulated community about whether such units are natural gas-fired EGUS pursuant to MATS or biomass-fired boilers subject to the Industrial Boiler NESHAP. We are revising the MATS rule to make clear that such units are biomass-fired boilers subject to the industrial boiler NESHAP. Similar revisions to the applicability provisions of the Industrial Boiler NESHAP have been proposed.[1]

5. Section 63.9991(c)(1) and (2) is being revised to clarify the conditions that are required in order to use the alternate sulfur dioxide (SO_2) limit.

6. Sections 63.10000(c)(1)(i)(A) and 63.10005(h) are revised to clarify the provisions of units designated as being low emitting EGUs (LEE) when an acid gas scrubber and a bypass stack are present.

7. Section 63.10000(c)(1)(i)(C) is added to allow EGUs the ability to seek LEE status if their bypass stacks vent through stacks that are able to measure emissions. In addition, the proposed language would allow EGUs with LEE status the ability to bypass emissions control devices during emergency periods provided certain fuel and time restrictions, along with notification requirements, occur.

The final MATS rule did not allow EGUs whose emissions control devices had bypasses to seek LEE status. Owners and operators of EGUs whose emissions control devices had no bypass stacks, but instead routed bypass emissions through main stacks equipped with emissions measurement capability, requested that we allow their EGUs to seek LEE status provided emissions were measured during bypass events. We believe that EGU owners or operators that have the ability to measure and report emissions during bypass events should be able to seek LEE status as long as bypass emissions are included in the calculations required to demonstrate the LEE status eligibility. For this reason, we are proposing to allow this option.

Also, a number of EGU owners or operators requested that we allow EGUs with LEE status the ability to bypass their emissions control devices in emergency conditions, provided that the EGUs were combusting clean fuels and that the bypass periods were of short duration.[2] We reviewed the requests and believe that control device bypass operation for up to 2 percent of EGU operating hours while combusting clean fuel during emergency periods is reasonable, provided a report detailing the emergency event, its cause, the corrective action taken to alleviate the emergency event, and estimates of the emissions released during the emergency event are provided. In addition, an EGU owner or operator must include these emergency emissions along with performance test results in assessing whether its EGU maintains LEE status. We seek comment on the adequacy of the restrictions associated with bypass conditions regarding maintaining LEE status.

8. Section 63.10000(c)(2)(iii) is revised to state that EGU owners or operators who choose to use quarterly testing and parametric monitoring for hydrogen fluoride (HF) or hydrogen chloride (HCl) compliance must include the continuous monitoring systems (CMS) that will be used in their site-specific monitoring plans to comply with the monitoring requirements.

9. Section 63.10000(m) is added to clarify that EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup may verify, instead of certify, monitoring systems used to generate data to meet the work practice standards. Moreover, this addition clarifies that those monitoring systems may be installed, verified, operated, maintained, and quality assured using manufacturer's specifications.

10. Section 63.10001 is revised to remove the affirmative defense provisions as explained in Section II below. The section is reserved.

11. Section 63.10005(a) is revised to clarify that different compliance demonstrations may require different and additional types of data collection and to clarify the date by which compliance must be demonstrated for existing EGUs.

12. Section 63.10005(a)(2) is revised to clarify the date by which compliance must be demonstrated for EGUs using CMS or sorbent trap monitoring systems.

13. Section 63.10005(a)(2)(i) is revised to clarify applicability of the provision to both the 30- and 90-boiler operating day performance testing requirements.

14. Section 63.10005(b)(1) is revised to clarify the time period allowed for existing EGUs to use stack test data collected prior to the applicable compliance date.

15. Section 63.10005(b)(6) is added to clarify the date EGUs must begin conducting required stack tests when stack test data collected prior to the applicable compliance date are submitted to satisfy the initial performance test requirement.

16. Section 63.10005(d)(3) and (d)(4)(i) is revised to more clearly state when compliance must be demonstrated.

17. Section 63.10005(f) is revised to clarify when sources must complete the initial boiler tune-up after the compliance date, and the timing for subsequent tune-ups when a tune-up conducted prior to the compliance date is used to satisfy the initial tune-up requirement.

18. Section 63.10005(h)(3) is revised to clarify that the alternate 30- and 90-day averaging provisions are both applicable to mercury (Hg) emission limits, and to clarify the sampling probe location.

19. Section 63.10005(i)(4) is revised to delete paragraphs (iii) and (iv). The identified test methods contain requirements for fuel sampling, not determining fuel moisture content, as required in the provision.

[1] Prepublication version found at *http://www.epa.gov/ttn/atw/boiler/boilerpg.html*. The prepublication version will be replaced with the **Federal Register** document when the proposal is published.

[2] To the extent these EGUs bypassed their control devices without measuring emissions, the hours of bypass operation would need to be reported as hours of monitoring deviation and subject to potential enforcement action.

20. Section 63.10006(f) is revised to specify EGU operational status with respect to performance testing; to identify the requirements—including make-up testing and reporting—if the performance testing schedule is missed apart from using existing skip procedures; and to identify intervals between performance tests. The final MATS rule had no provision that allowed an EGU owner or operator to skip a required performance test if its EGU was otherwise not operating; we did not believe the rule needed to be explicit in stating that EGUs need not be turned on solely to conduct performance testing. However, we have received questions regarding this circumstance. We believe it is appropriate to allow an EGU owner or operator the ability to skip a required performance test if its EGU is not otherwise operating, and are proposing this in this action. The final MATS rule had no provisions regarding make-up testing and reporting should a regularly scheduled performance test be missed for reasons other than the existing skip procedures. We believe it is appropriate to specify a schedule for required make-up testing and reporting, and are proposing such a schedule in this action. The final MATS rule specified the time periods between performance tests, but EGU owners or operators expressed concerns about being able to adhere to such a schedule. We believe their concerns about having too tight a timeline for retesting to occur and our concern about having a sufficient interval of time between tests such that the results better reflect characteristics of different periods can be addressed by specifying a minimum interval of time between subsequent performance tests, which we are proposing in this action. We welcome comments as to the need for, as well as efficacy of, these proposed revisions, as well as on these proposed intervals.

21. Section 63.10009(a)(2) and (a)(2)(i) is revised to clarify that the 90-boiler operating day averaging period is available as an option for Hg emissions from non-low rank virgin coal-fired EGUs (*i.e.,* EGUs in the subcategory ''unit designed for coal ≥8,300 Btu/lb''). In the final MATS (77 FR 9303 at 9385), we had indicated that we were providing the 90-boiler operating day averaging period as an alternative compliance approach (to the standard 30-boiler operating day averaging period) for Hg emissions from EGUs in that subcategory. However, the regulatory text in 40 CFR 63.10009(a)(2) did not clearly reflect this option.

The term ''gross electric output'' is also corrected to ''gross output'' which is the term defined in 40 CFR 63.10042.

22. Section 63.10009(b)(1) is revised to clarify group eligibility equations 1a and 1b. These equations were developed to provide EGU owners or operators a quick method for determining if their emissions averaging group could meet the emissions limit when operated at the maximum rated heat input and, in some cases, steam production. Commenters reported difficulty in using the equations in the final rule, so the equations have been revised so that individual EGU characteristics, whether from CEMS or stack testing results, are easier to input. We request comment on the proposed revisions concerning their usefulness in calculating the maximum potential emissions rate from an emissions averaging group. The term ''gross electric output'' is also corrected to ''gross output'' which is the term defined in 40 CFR 63.10042.

23. Section 63.10009(b)(2) and (3) is revised to correct the term ''gross electric output'' to ''gross output'' which is the term defined in 40 CFR 63.10042.

24. Section 63.10009(f) is revised to clarify the conditions for determining the ability of the emissions averaging group to meet the emissions limit and to clarify use of the alternate Hg emission limit. Instead of relying on the maximum normal operating load of each EGU in determining the ability of the emissions averaging group to demonstrate initial compliance, as was contained in the final MATS rule, we are proposing in this action to use the maximum possible heat input or gross output of each EGU in determining the ability of the emission averaging group to demonstrate initial compliance. In addition, instead of calculating the maximum weighted average emissions rate, as used in the final MATS rule, we are proposing in this action to calculate the initial weighted average emissions rate. Finally, instead of specifying just one date for submitting an emissions averaging plan, as was done in the final MATS rule, we are proposing in this action to allow an EGU owner or operator the flexibility to choose other dates to begin using an emissions averaging plan by allowing the submission of an emissions averaging plan at least 120 days before the date on which emissions averaging is to begin. We believe these changes will provide additional flexibility without undermining the enforceability of the final standards.

25. Section 63.10009(f)(2), (g)(1), (g)(2), and (j)(1)(ii) is revised to correct the term ''gross electric output'' to ''gross output'' which is the term defined in 40 CFR 63.10042.

26. Section 63.10010(a)(4) is revised to add a requirement to route exhaust gases that bypass emissions control devices through stacks that contain monitoring so that emissions can be measured and to clarify that hours that a bypass stack is in use are to be counted as hours of deviation from monitoring requirements.

27. Section 63.10010(f)(3) is revised to clarify that 30-boiler operating day rolling averages are to be based only on valid hourly SO_2 emission rates.

28. Section 63.10010(h)(6)(i) and (ii), (i)(5)(A) and (B), and (j)(4)(i)(A) and (B) is revised to clarify that data collected during certain periods are not to be included in compliance assessments but such periods are to be included in annual deviation reports. The final MATS rule established that all data collected with PM CPMS, PM CEMS, and HAP metals CEMS during all boiler operating hours were to be used in assessing compliance except those data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, required quality assurance or quality control activities, or monitoring out-of-control periods. In addition, the final MATS rule sections combined the requirement to report the periods when data collected during these operating periods as deviations into one long sentence. In this action, we are proposing to separate these requirements into two sentences to ease readability.

29. Section 63.10010(l)(i) is revised to replace the incorrect reference to § 63.7(e) with the correct reference to § 63.8(d)(2).

30. Section 63.10010(l) and (l)(4) is revised to clarify that EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup may verify, instead of certify, monitoring systems used to generate data to meet the work practice standards. Moreover, this revision clarifies that those monitoring systems may be installed, verified, operated, maintained, and quality assured using manufacturer's specifications.

31. Section 63.10011(b) is revised to remove the incorrect reference to Table 4 and to replace the incorrect reference to Table 7 with the correct reference to Table 6.

32. Section 63.10011(c)(1) and (2) is revised to clarify the date by which compliance must be demonstrated by EGUs that use CEMS or sorbent trap monitoring systems. In addition, § 63.10011(c)(1) is revised to clarify that

the alternate Hg emission limit may be used.

33. Section 63.10011(e) is revised to replace ''according to'' with ''in accordance with.''

34. Section 63.10011(g)(4)(v)(A) and Table 3 are revised to clarify our intent regarding clean fuel use ''to the maximum extent possible.'' Our goal in the work practice is to minimize HAP emissions during startup and shutdown periods, and that goal can be accomplished by minimizing primary fuel use and maximizing clean fuel use because of the inherently low HAP content of the defined ''clean fuels.'' As stated in the preamble to the final startup and shutdown reconsideration rule, EGUs that chose to comply with the alternative work practice will be required to have sufficient clean fuel capacity to startup and warm the facility to the point where the primary PM controls can be brought on line at the same time as, or within 1 hour of, the addition of the primary fuel to the EGU. 79 FR 68777 at 68779, November 19, 2014. We recognize that the clean fuel requirement may require sources to increase clean fuel capacity, modify the startup burners, and/or take additional actions to comply with the final rule. 79 FR 68777 at 68779, November 19, 2014. Thus, we expect clean fuels to be combusted in at least the amount needed to bring the emissions control devices to operational levels necessary to comply with the numeric standards at the end of startup. We do not expect clean fuel use to the extent that it compromises the integrity of the boiler or its control devices; neither do we expect clean fuel to be combusted in excess of the amount needed to bring the emissions control devices to expected operational levels. We have determined that it is appropriate to slightly revise the language in the November 19, 2014, final rule. 79 FR 68777. The proposed revision would change the language from ''to the maximum extent possible'' to ''to the maximum extent practicable, taking into account boiler or control device integrity.''

35. Section 63.10020(e) is revised to clarify that it applies only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup. In addition, the undefined term ''electrical load'' has been replaced with the defined term ''gross output'' and the incorrect terms ''liquid to fuel ratio'' and ''the differential pressure of the liquid'' in § 63.10020(e)(3)(i)(E) have been replaced with the correct terms ''liquid to flue gas ratio'' and ''the pressure drop across the scrubber.'' Finally, in order to clarify our intent that existing instrumentation or engineering calculations can be used to provide flow information, § 63.10020(e)(3)(i)(A) and (B) is revised to remove the term ''rate'' and to acknowledge the use of existing combustion air flow monitors or combustion equations.

36. Section 63.10021(d)(3) is revised to clarify the type of monitoring that is to be used to demonstrate compliance.

37. Section 63.10021(e) is revised to clarify the condition that allows delay of burner inspections for initial boiler tune-ups.

38. Section 63.10021(e)(9)(i) and (ii) is revised to clarify the dates that tune-ups must be reported.

39. Section 63.10023(b) and Table 6 are revised to clarify that all EGUs using PM continuous parametric monitoring systems (CPMS) for compliance purposes are to follow the same procedure for determining the operating limit. The final rule allowed existing EGUs to determine the operating limit based on the highest 1-hour average PM CPMS value recorded during a performance test, even if that average time was associated with a test run in excess of the numeric standards, while new EGUs were required to use a scaling factor or the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish the operating limit.[3] We believe all EGUs should use a consistent set of procedures for both new and existing EGUs for establishing an operating PM limit, so we are proposing in this action to revise the procedures for existing EGUs. The procedures for existing EGUs, contained in § 63.10023(b)(1) are reserved, and § 63.10023(b)(2) and Table 6 are revised so that all EGUs are to follow the operating limit development procedures for new EGUs (*i.e.,* use a scaling factor or the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish the operating limit).

40. Section 63.10030(e)(1) is revised to replace the phrase ''identification of which subcategory the source is in'' with ''identification of the subcategory of the source.''

41. Section 63.10030(e)(7)(i) is revised to clarify that the date of each stack test conducted for purposes of demonstrating LEE eligibility is to be provided. The final rule establishes that each test for pollutants other than Hg conducted over a 3-year period must meet the LEE emission limit in order for an EGU to be eligible for LEE status.

42. Section 63.10030(e)(7)(iii) is added to establish the procedures by which an EGU owner or operator may switch between mass per heat input and mass per gross output emission limits. The EPA has received questions about how frequently an existing EGU could alternate between the two compliance formats. Although we did not envision that an owner or operator of an existing EGU would want to change the basis of the EGU's emission limits, we believe it is reasonable to allow such action provided certain conditions, including performance testing demonstrating compliance with the new format, submission of a written request to change formats, and receipt of permission from the Administrator to change formats, are met. We request comment on these procedures, as well as on the concept of switching emission limits, particularly during performance averaging periods.

43. Section 63.10030(e)(8)(i) is revised to clarify that it applies only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup. Moreover, the provisions requiring a description of PM control device efficiencies and PM emission rates are revised to clarify that such efficiencies and emission rates are those of periods other than startup and shutdown periods. As the uncontrolled emission rates can be calculated from control device efficiencies and corresponding emission rates, the provisions requiring reporting of uncontrolled emission rates have been removed.

In addition, as current EGU characteristics are most relevant for compliance with the MATS rule, the requirements concerning identification of intermediate changes to the EGU design have been removed. In order to reduce redundant reporting, the rule has been revised to require no additional identification if no changes to the EGU's design characteristics have occurred.

Finally, § 63.10030(e)(8)(ii)(A) has been revised to remove the requirement for use of an independent professional engineer. Consistent with the discussion contained in 71 FR 16869 (April 4, 2006), we believe that a professional engineer, regardless of whether they are independent, is able to give a fair technical review because of the programs established by the state licensing boards, which serve to enforce objectivity from each registrant. We believe that the revision will allow EGUs to reduce burden without compromising environmental safety by

[3] See the description of the ''third approach'' at 79 FR 24708 (April 24, 2013).

using in-house expertise. Professional engineers employed by an EGU should be more familiar with its design and operational characteristics and should be in a position to expedite collection and submission of required information.

44. Section 63.10030(f) is revised to add notification requirements for EGUs that move in and out of MATS applicability.

45. Section 63.10031(c)(4) is revised to clarify the reporting requirements for EGU tune-ups.

46. Section 63.10031(c)(5) is revised to clarify that it applies only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.

47. Section 63.10031(c)(6) is revised to add emergency bypass reporting for EGUs with LEE status.

48. Section 63.10031(f)(5) is revised to state that the Administrator retains the right to require submittal of reports subject to paragraph (f)(4), as well as paragraphs (f)(1) through (3).

49. Section 63.10032(f) is revised to clarify that the requirements of § 63.10032(f)(1) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (1) of the definition of startup, while the requirements of § 63.10032(f)(2) apply only to those EGU owners or operators who choose to meet the work practice standards contained in paragraph (2) of the definition of startup.

50. The definitions of ''Coal-fired electric utility steam generating unit,'' ''Coal refuse,'' ''Fossil fuel-fired,'' ''Integrated gasification combined cycle electric utility steam generating unit or IGCC,'' ''Limited-use liquid oil-fired subcategory,'' ''Natural gas-fired electric utility steam generating unit,'' and ''Oil-fired electric utility steam generating unit'' in § 63.10042 are revised to clarify the period of time to be included in determining the source's applicability to the MATS.

During the comment period on the proposed MATS rule, industry noted that many EGUs would convert to natural gas or other non-fossil fuel prior to the compliance date and those sources would remain subject to MATS because the proposed rule required sources to determine applicability based on the 3 calendar years prior to the compliance date. *See, e.g.,* 40 CFR 63.10042 (definition of ''fossil fuel-fired''). The EPA agreed that this was not the EPA's intent and in the final MATS rule revised several definitions, including the definition of fossil fuel-fired, that required sources to evaluate usage after the applicable compliance date.

The EPA inadvertently created confusion in its attempt to address industry concerns in the final MATS rule. The confusion is best illustrated by an analysis of the proposed and final definitions of ''fossil fuel-fired.'' The EPA's proposed definition stated, in part, that ''[i]n addition, fossil fuel-fired means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input during the *previous 3 calendar years* or for more than 15.0 percent of the annual heat input *during any one of those calendar year.*'' *See* 76 FR 24975 at 25123 (emphasis added). The intent in this definition was to require sources to look at the usage from the 3 previous years to determine if the average or the single year usage from those 3 years exceeded either of the thresholds.

To address the commenters' concern, the EPA revised the definition of ''fossil fuel-fired'' in the final rule to state, in part, that ''[i]n addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual year input during *any 3 consecutive calendar years* or for more than 15.0 percent of the annual heat input during *any one calendar year* after the applicable compliance date.'' 40 CFR 63.10042 (emphasis added). This definition creates at least two potential compliance issues: (1) It creates confusion as to how sources are to determine MATS applicability during the first 3 years after the applicable compliance date; and (2) it subjects sources to MATS in perpetuity if the usage thresholds are ever exceeded after the compliance date—''any 3 consecutive calendar years'' or ''any one calendar year'' ''after the applicable compliance date.''

The proposed revisions to the definitions address both issues. Concerning applicability in the first 3 years after the applicable compliance date, this proposed rule states that sources must project their coal and oil usage for the first 3 years to determine whether the EGU will exceed either the 10.0 or 15.0 percent threshold. The EPA's understanding is that sources know with sufficient specificity the fuels they will use in advance, and requiring sources to project their usage accommodates industry concerns that the sources that are converting to natural gas or biomass prior to the compliance date not be subject to MATS. The EPA is also proposing that sources that permanently convert to natural gas or biomass after the compliance date are no longer subject to MATS, notwithstanding the coal or oil usage the previous 3 calendar years.

The EPA is also proposing to revise the definitions to make clear that after the first 3 years of compliance, EGUs are required to evaluate applicability based on coal or oil usage from the 3 previous calendar years on an annual rolling basis, consistent with the definition of ''fossil fuel-fired'' proposed in the MATS rule. This proposed change will prevent EGUs from being subject to MATS in perpetuity if they exceed the 10 or 15 percent threshold at any time after the compliance date.

A definition of ''neural network'' is also being added because the term is used in 40 CFR 63.10005(f), 63.10006(i), and 63.10021(e) and Table 3 to subpart UUUUU of Part 63 but is not defined.

51. Table 1 to subpart UUUUU of Part 63 is revised to correct the term ''gross electric output'' to ''gross output'' which is the term defined in 40 CFR 63.10042 in footnotes 1, 4, and 5.

52. Table 2 to subpart UUUUU of Part 63 is revised to correct the term ''gross electric output'' to ''gross output'' which is the term defined in 40 CFR 63.10042 in footnote 2. Provision 1(c) (the Hg limit for EGUs in the subcategory ''unit designed for coal ≥8,300 Btu/lb'') is also revised to clarify the applicability of the alternate 90-boiler operating day compliance option.

53. Table 3 to subpart UUUUU of Part 63 is revised as described earlier to clarify the term ''maximum extent possible.''

In addition, we have received questions concerning the interpretation of the definition of startup, particularly the language defining the end of startup. Industry has inquired whether the triggering action is either the generation of electricity or of steam for any useful purpose under both definitions of startup. The EPA does interpret the end of startup in a consistent manner as between the two definitions. Specifically, we interpret the phrase ''. . . when any of the steam from the boiler is used . . . for any other purpose,'' contained in paragraph (1) of the definition of startup, to have the same meaning as the phrase ''for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler,'' as provided in paragraph (2) of the definition of startup. EGUs trigger the end of startup whenever they use either electricity or steam for any useful purpose either on or offsite.

54. Table 4 to subpart UUUUU of Part 63 is revised to clarify that existing as well as new EGUs using PM CPMS share the same procedures for

developing operating limits (*i.e.,* those that are based on the higher of a parameter scaled from all values obtained during an individual emissions test to 75 percent of the emissions limit or the average parameter value obtained from all runs of an individual emission test as the operating limit provided that the result of the individual emissions test met the emissions limit requirements).

55. Table 5 to subpart UUUUU of Part 63 is revised to state that when using Method 5, you are to report the average of the final 2 filter weighings, and to clarify that when using Method 29, you are to report the metals matrix spike and recovery levels. These provisions are needed for the required electronic reporting.

56. Table 6 to subpart UUUUU of Part 63 is revised to clarify that existing, as well as new, EGUs using PM CPMS share the same procedures for developing operating limits (*i.e.,* those that are based on the higher of a parameter scaled from all values obtained during an individual emissions test to 75 percent of the emissions limit or the average parameter value obtained from all runs of an individual emission test as the operating limit provided that the result of the individual emissions test met the emissions limit).

57. Table 8 to subpart UUUUU of Part 63 is revised to clarify that compliance reports are to include information required by § 63.10031(c)(5) and (6).

58. Table 9 to subpart UUUUU of Part 63 is revised to correct an inadvertent omission of 30-day notification requirements of § 63.9.

59. Paragraphs 4.1.1.3 and 5.1.2.3 and Tables A–1 and A–2 to Appendix A to subpart UUUUU of Part 63 are revised to adjust Hg CEMS language regarding converters. Research has shown that all Hg CEMS need weekly single-level system integrity checks.

60. Paragraph 7.1.2.5 to Appendix A to subpart UUUUU of Part 63 is added to require that owners or operators flag EGUs that are part of emission averaging groups.

61. Paragraph 3.2.1.2.1 of Appendix A to subpart UUUUU of Part 63 is revised to specifically indicate that Hg gas generators and cylinders are allowed.

62. Paragraphs 4.1.1.1, Table A–1, Table A–2, 5.1.2.1, and 4.1.1.3 of Appendix A to subpart UUUUU of Part 63 are revised to exclude use of oxidized Hg gas standards for daily calibration of Hg CEMS.

63. Paragraph 5.1.2.3 of Appendix A to subpart UUUUU of Part 63 is revised to make the weekly single level system integrity check mandatory.

64. Paragraphs 4.1.1.5.2, Table A–1, Table A–2, and 4.1.1.5 of Appendix A to subpart UUUUU of Part 63 are revised to provide an alternative relative accuracy test audit (RATA) procedure for EGUs with low emissions that is related specifically to the emission standard.

65. Paragraph 5.2.1 of Appendix A to subpart UUUUU of Part 63 is revised to correct the number of days for sorbent trap use from 14 to 15.

66. Paragraph 6.2.2.3 of Appendix A to subpart UUUUU of Part 63 is revised to clarify that the 90-day alternative Hg standard may be used and that electrical output is gross output.

67. Paragraph 7.1.2.6 of Appendix A to subpart UUUUU of Part 63 is added to clarify that EGU owners or operators are to keep records of their EGUs that constitute emissions averaging groups.

68. Paragraphs 2.1, 2.3, 2.3.1, 2.3.2, 3.1, 3.2, 3.3, 5, 5.1, 5.2, and 5.3 of Appendix B to subpart UUUUU of Part 63 are revised to clarify that use of Performance Specification (PS) 18, a proposed technology-neutral PS for HCl CEMS which will soon be promulgated, will be allowed. Consistent with our statements in the final rule, we expect that PS 18 will likely be promulgated in advance of the rule's compliance date. An EGU owner or operator who wishes to use proposed PS 18, along with quality assurance (QA) procedure 6, prior to their promulgation dates is welcome to submit an alternative monitoring request in accordance with the requirements of § 63.8(f) for use of proposed PS 18 and QA Procedure 6 to us.

69. Paragraph 5.4 of Appendix B to subpart UUUUU of Part 63 is added as part of the renumbering due to the addition of PS 18.

70. Paragraph 8 of Appendix B to subpart UUUUU of Part 63 is revised to accommodate use of PS 18.

71. Paragraphs 10.1.8, 10.1.8.1, 10.1.8.1.1, and 10.1.8.1.2 of Appendix B to Subpart UUUUU of Part 63 are revised as part of the renumbering due to the addition of PS 18.

72. Paragraph 10.1.8.1.3 of Appendix B to Subpart UUUUU of Part 63 is revised to clarify that records of relative accuracy audits (RAAs) are also required.

73. Paragraphs 10.1.8.2, 10.1.8.1.2.1, and 10.1.8.1.2.2 of Appendix B to Subpart UUUUU of Part 63 are revised to clarify the quarterly gas audit recordkeeping requirements for PS 15 and the quarterly data accuracy assessments for PS 18 (which are reserved).

74. Paragraph 11.4 of Appendix B to Subpart UUUUU of Part 63 is revised to replace the incorrect abbreviation ''*i.e.*'' with ''*e.g.*''

75. Paragraph 11.4.2 of Appendix B to Subpart UUUUU of Part 63 is revised to specify the requirements of the daily beam intensity checks for EGUs using PS 18.

76. Paragraphs 11.4.2.1, 11.4.2.2, 11.4.2.3, 11.4.2.4, 11.4.2.5, 11.4.2.6, 11.4.2.7, 11.4.2.8, 11.4.2.9, 11.4.2.10, 11.4.2.11, 11.4.2.12, and 11.4.2.13 of Appendix B to Subpart UUUUU of Part 63 are revised to hold the requirements of the daily beam intensity checks for PS 18 (which are reserved).

77. Paragraph 11.4.3 of Appendix B to Subpart UUUUU of Part 63 is revised to reflect the reporting requirements for PS 15.

78. Paragraphs 11.4.3.1, 11.4.3.2, 11.4.3.3, 11.4.3.4, 11.4.3.5, 11.4.3.6, 11.4.3.7, 11.4.3.8, 11.4.3.9, 11.4.3.10, 11.4.3.11, 11.4.3.12, and 11.4.3.13 of Appendix B to Subpart UUUUU of Part 63 are revised to include PS 15 reporting requirements.

79. Paragraph 11.4.4 of Appendix B to Subpart UUUUU of Part 63 is revised to reserve the reporting requirements for quarterly parameter verification checks for PS 18.

80. Paragraphs 11.4.4.1, 11.4.5, 11.4.5.1, 11.4.6, 11.4.6.1 of Appendix B to Subpart UUUUU of Part 63 are added to reserve the reporting requirements for quarterly gas audit information and for quarterly dynamic spiking for PS 18.

81. Paragraph 11.4.7 of Appendix B to Subpart UUUUU of Part 63 is added to include reporting requirements for RAAs.

82. Paragraphs 11.4.7.1, 11.4.7.2, 11.4.7.3, 11.4.7.4, 11.4.7.5, 11.4.7.6, 11.4.7.7, 11.4.7.8, 11.4.7.9, 11.4.7.10, 11.4.7.11, 11.4.7.12, and 11.4.7.13 of Appendix B to Subpart UUUUU of Part 63 are added as part of the renumbering due to the addition of PS 18.

83. Paragraph 11.5.3.4 of Appendix B to Subpart UUUUU of Part 63 is revised to include reporting requirements for beam intensity checks for PS 18.

II. Affirmative Defense for Violation of Emission Standards During Malfunction

In several prior CAA section 112 and CAA section 129 rules, including this rule, the EPA included an affirmative defense to civil penalties for violations caused by malfunctions in an effort to create a system that incorporates some flexibility, recognizing that there is a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances entirely beyond the control of the source. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility in these circumstances, it included the affirmative defense to provide a more formalized approach and more regulatory clarity. *See Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); *but see Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977) (requiring a more formalized approach to consideration of ''upsets beyond the control of the permit holder.''). Under the EPA's regulatory affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. Recently, the United States Court of Appeals for the District of Columbia Circuit vacated an affirmative defense in one of the EPA's CAA section 112 regulations. *NRDC* v. *EPA,* 749 F.3d 1055 (D.C. Cir., 2014) (vacating affirmative defense provisions in CAA section 112 rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the EPA. Specifically, the court found: ''As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' '' *See NRDC,* 749 F.3d at 1063 (''[U]nder this statute, deciding whether penalties are 'appropriate' . . . is a job for the courts, not EPA.'').

In light of *NRDC,* the EPA is proposing to remove the regulatory affirmative defense provision in the current rule. As explained above, if a source is unable to comply with emissions standards as a result of a malfunction, the EPA may use its case-by-case enforcement discretion to provide flexibility, as appropriate. Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. Cf. *NRDC,* at 1064 (arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions.

III. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

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

This action is not a significant regulatory action and was, therefore, not subject to review by the Office of Management and Budget (OMB).

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden. This action clarifies but does not change the information collection requirements previously finalized and, as a result, does not impose any additional burden on industry. The OMB has previously approved the information collection requirements contained in the existing regulations (see 77 FR 9303, February 16, 2012) under the provisions of the PRA, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0567. The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities. The EPA has determined that none of the small entities will experience a significant impact because the action imposes no additional regulatory requirements on owners or operators of affected sources.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate as described in 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. Executive Order 13132: Federalism

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

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

This action does not have tribal implications as specified in Executive Order 13175. This action does not significantly or uniquely affect the communities of tribal governments. Thus, Executive Order 13175, does not apply to this action.

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

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

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

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

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The corrections do not involve special consideration of environmental justice-related issues as required by Executive Order 12898, and an evaluation was not necessary for this action.

The EPA's compliance with the above statutes and Executive Orders for the underlying rule is discussed in the February 16, 2012, **Federal Register** document containing ''National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-

Institutional Steam Generating Units.'' (77 FR 9303).

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

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

Dated: December 19, 2014.

Gina McCarthy,

Administrator.

For the reasons discussed in the preamble, the EPA proposes to correct and 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. Section 60.48Da is amended by revising paragraph (f) to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with the applicable daily average PM emissions limit is determined by calculating the arithmetic average of all hourly emission rates each boiler operating day, except for data obtained during startup, shutdown, or malfunction periods. Daily averages 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 or reconstruction commenced after May 3, 2011 that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in § 60.42Da is determined on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup and shutdown.

* * * * *

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

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

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

■ 4. Section 63.9983 is amended by:

■ a. Revising the section heading and paragraphs (a), (b), and (c); and

■ Adding paragraph (e).

The revisions and addition read as follows:

§ 63.9983 Are any fossil fuel-fired electric generating units not subject to this subpart?

* * * * *

(a) Any unit designated as a major source stationary combustion turbine subject to 40 CFR part 63, subpart YYYY and any unit designated as an area source stationary combustion turbine, other than an integrated gasification combined cycle (IGCC) unit.

(b) Any electric utility steam generating unit that is not a coal- or oil-fired EGU and that meets the definition of a natural gas-fired EGU in § 63.10042.

(c) Any electric utility steam generating unit that has the capability of combusting more than 25 MW of coal or oil but does not meet the definition of a coal- or oil-fired EGU because it did not fire sufficient coal or oil to satisfy the average annual heat input requirement set forth in the definitions for coal-fired and oil-fired EGUs in § 63.10042. Heat input means heat derived from combustion of fuel in an EGU and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and industrial boilers).

* * * * *

(e) Any electric utility steam generating unit that meets the definition of a natural gas-fired EGU under this subpart and that fires at least 10 percent biomass is an industrial boiler subject to standards established under 40 CFR part 63, subpart DDDDD, if it otherwise meets the applicability provisions in that rule.

■ 5. Section 63.9991 is amended by revising paragraphs (c)(1) and (2) to read as follows:

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

* * * * *

(c) * * *

(1) Has a system using wet or dry flue gas desulfurization technology and an SO_2 continuous emissions monitoring system (CEMS) installed on the EGU; and

(2) At all times, you operate the wet or dry flue gas desulfurization technology and the SO_2 CEMS installed on the EGU consistent with § 63.10000(b).

■ 6. Section 63.10000 is amended by:

■ a. Revising paragraph (c)(1)(i);

■ b. Revising paragraph (c)(2)(iii); and

■ c. Adding paragraph (m).

The revisions and additions read as follows:

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

* * * * *

(c)(1) * * *

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

(A) You may not pursue the LEE option if your coal-fired, IGCC, or solid oil-derived fuel-fired EGU is equipped with a main stack and a bypass stack exhaust configuration that allows the EGU to bypass any pollutant control device.

(B) You may not pursue the LEE option for Hg if your coal-fired, solid oil-derived fuel-fired EGU or IGCC EGU is new.

(C) Notwithstanding paragraph (c)(1)(i)(A) of this section, you may pursue the LEE option provided:

(*1*) Your control device bypass stack is routed through the EGU main stack so that emissions are measured during the bypass event; or

(*2*) You bypass your EGU control device only during emergency periods for no more than a total of 2 percent of your EGU's annual operating hours; you use clean fuels to the maximum extent practicable during an emergency period; and you prepare and submit a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. You must include these emergency emissions along with performance test results in assessing whether your EGU maintains LEE status.

* * * * *

(2) * * *

(iii) If your existing liquid oil-fired unit does not qualify as a LEE for hydrogen chloride (HCl) or for hydrogen fluoride (HF), you may demonstrate initial and continuous compliance through use of an HCl CEMS, an HF CEMS, or an HCl and HF CEMS, installed and operated in accordance with Appendix B to this rule. As an alternative to HCl CEMS, HF CEMS, or HCl and HF CEMS, you may demonstrate initial and continuous compliance through quarterly performance testing and parametric monitoring for HCl and HF. If you choose to use quarterly testing and parametric monitoring, then you must also develop a site-specific monitoring plan that identifies the CMS you will use to ensure that the operations of the EGU remains consistent with those during the performance test. As another alternative, you may measure or obtain, and keep records of, fuel moisture content; as long as fuel moisture does not exceed 1.0 percent by weight, you need not conduct other HCl or HF monitoring or testing.

* * * * *

(m) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, on or before the date your EGU is subject to this subpart, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with § 63.10020(e).

(1) You may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system.

(2) You must collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods.

§ 63.10001 [Removed and reserved]

■ 7. Section 63.10001 is removed and reserved.

■ 8. Section 63.10005 is amended by:

■ a. Revising paragraphs (a) introductory text, (a)(2) introductory text and (a)(2)(i);

■ b. Revising paragraph (b)(1);

■ c. Adding paragraph (b)(6);

■ d. Revising paragraphs (d)(3), (d)(4)(i);

■ f. Revising paragraph (f);

■ g. Revising paragraph (h) introductory text, and (h)(3) introductory text;

■ h. Removing paragraphs (i)(4)(iii) and (iv).

The revisions and additions read as follows:

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

(a) *General requirements.* For each of your affected EGUs, you must demonstrate initial compliance with each applicable emissions limit in Table 1 or 2 of this subpart through performance testing. Where two emissions limits are specified for a particular pollutant (*e.g.,* a heat input-based limit in lb/MMBtu and an electrical output-based limit in lb/MWh), you may demonstrate compliance with either emission limit. For a particular compliance demonstration, you may be required to conduct one or more of the following activities in conjunction with performance testing: collection of data, *e.g.,* hourly electrical load data (megawatts); establishment of operating limits according to § 63.10011 and Tables 4 and 7 to this subpart; and CMS performance evaluations. In all cases, you must demonstrate initial compliance no later than the date in paragraph (f) of this section for tune-up work practices for existing EGUs; the date that compliance must be demonstrated, as given in § 63.9984 for other requirements for existing EGUs; and in paragraph (g) of this section for all requirements for new EGUs.

(1) * * *

(2) To demonstrate initial compliance using either a CMS that measures HAP concentrations directly (*i.e.,* an Hg, HCl, or HF CEMS, or a sorbent trap monitoring system) or an SO_2 or PM CEMS, the initial performance test may occur on or before the first averaging period (30- or, for certain coal-fired existing EGUs that use emissions averaging for Hg, 90-boiler operating days) after the date that compliance with this subpart is required but must occur such that the averaging period is completed on or before the date that compliance must be demonstrated.

(i) The CMS performance test must demonstrate compliance with the applicable Hg, HCl, HF, PM, or SO_2 emissions limit in Table 1 or 2 to this subpart.

* * * * *

(b) * * *

(1) For a performance test of an existing EGU based on stack test data, the test was conducted between 180 and 365 calendar days prior to the date that compliance must be demonstrated as specified in § 63.9984.

* * * * *

(6) If the performance test data that are collected prior to the date that compliance must be demonstrated are used to demonstrate initial compliance with applicable emissions limits, the interval for subsequent stack tests begins on the date that compliance must be demonstrated.

* * * * *

(d) * * *

(3) For affected EGUs that are either required to or elect to demonstrate initial compliance with the applicable Hg emission limit in Table 1 or 2 of this subpart using Hg CEMS or sorbent trap monitoring systems, initial compliance must be demonstrated no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs. Initial compliance is achieved if the arithmetic average of 30- (or 90-) boiler operating days of quality-assured CEMS (or sorbent trap monitoring system) data, expressed in units of the standard (see section 6.2 of appendix A to this subpart), meets the applicable Hg emission limit in Table 1 or 2 to this subpart.

(4) * * *

(i) You must demonstrate initial compliance no later than the applicable date specified in § 63.9984(f) for existing EGUs and in paragraph (g) of this section for new EGUs.

* * * * *

(f) For an existing EGU without a neural network, a tune-up must occur on or before 180 days after April 16, 2015. For an existing EGU with a neural network, a tune-up must occur on or before 180 days after April 16, 2016. If a tune-up occurs prior to April 16, 2015, you must keep records showing that the operating conditions remain the same and that the tune-up met all rule requirements.

* * * * *

(h) *Low emitting EGUs.* The provisions of this paragraph (h) apply to pollutants with emissions limits from new EGUs except Hg and to all pollutants with emissions limits from existing EGUs. You may pursue this compliance option unless prohibited pursuant to § 63.10000(c)(1)(i).

* * * * *

(3) For Hg, you must conduct a 30- (or 90-) boiler operating day performance test using Method 30B in appendix A–8 to part 60 of this chapter to determine whether a unit qualifies for LEE status. Locate the Method 30B sampling probe tip at a point within 10 percent of the duct area centered about the duct's

centroid at a location that meets Method 1 in appendix A–1 to part 60 of this chapter and conduct at least three nominally equal length test runs over the 30-boiler operating day test period. Collect Hg emissions data continuously over the entire test period (except when changing sorbent traps or performing required reference method QA procedures). As an alternative to constant rate sampling per Method 30B, you may use proportional sampling per section 8.2.2 of Performance Specification 12 B in appendix B to part 60 of this chapter.

* * * * *

■ 9. Section 63.10006 is amended by revising paragraph (f) to read as follows:

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

* * * * *

(f) *Time between performance tests.* (1) Notwithstanding the provisions of § 63.10021(d)(1), the requirements listed in paragraphs (g) and (h) of this section, and the requirements of paragraph (f)(3) of this section, you must complete performance tests for your EGU as follows:

(i) At least 45 calendar days must separate performance tests conducted every quarter;

(ii) At least 370 calendar days must separate performance tests conducted every year; and

(iii) At least 1,050 calendar days must separate performance tests conducted every 3 years.

(2) Although you are not required to operate your EGU solely in order to conduct a performance test, you must conduct a performance test in the 4th quarter of a calendar year if your EGU has skipped performance tests in the 3 quarters of the calendar year.

(3) If your EGU misses a performance test deadline due to being inoperative and if you have at least 168 boiler operating hours in the next test period, you must complete an additional performance test in that period as follows:

(i) At least 15 calendar days must separate two performance tests conducted in the same quarter.

(ii) At least 107 calendar days must separate two performance tests conducted in the same calendar year.

(iii) At least 350 calendar days must separate two performance tests conducted in the same 3 year period.

* * * * *

■ 10. Section 63.10009 is amended by:

■ a. Revising paragraphs (a)(2) introductory text and (a)(2)(i);

■ b. Revising paragraphs (b)(1) through (3);

■ c. Revising paragraphs (f) introductory text and paragraph (f)(2);

■ d. Revising paragraphs (g)(1) and (2); and

■ e. Revising paragraph (j)(1)(ii).

The revisions read as follows:

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

(a) * * *

(2) You may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if your averaged Hg emissions for EGUs in the ‘‘unit designed for coal ≥8,300 Btu/lb’’ subcategory are equal to or less than 1.2 lb/TBtu or 1.3E–2 lb/GWh on a 30-boiler operating day basis or if your averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the ‘‘unit designed for coal ≥8,300 Btu/lb’’ subcategory, the averaging time for emissions averaging for pollutants is 30 days (rolling daily) using data from CEMS or a combination of data from CEMS and manual performance testing. The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E–2 lb/GWh) from EGUs in the ‘‘unit designed for coal ≥8,300 Btu/lb’’ subcategory is 90-boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of monitoring data and data from manual performance testing. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group has operated 30 (or 90) days. You must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) days during the preceding 30 (or 90) group boiler days.

(i) You may choose to have your EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant).

* * * * *

(b) * * *

(1) *Group eligibility equations.*

$$WAER_m = \frac{\sum_{j=1}^{p}\left[\left(\sum_{i=1}^{n} Herm_{i,j}\right) \times Rmm_j \times q_j\right] + \sum_{k=1}^{m} Ter_k \times Rmt_k \times r_k}{\left(\sum_{j=1}^{p} Rmm_j \times q_j\right) + \left(\sum_{k=1}^{m} Rmt_k \times r_k\right)} \quad (Eq.\ 1a)$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = hourly emission rate (*e.g.,* lb/MMBtu, lb/MWh) from CEMS or sorbent trap monitoring for hour i from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = hours in an averaging period (*e.g.,* 720 for a 30-group boiler operating day averaging period or 2160 for a 90-group boiler operating day averaging period),

q_j = hours in an averaging period for EGU j (*e.g.,* 720 for a 30-group boiler operating day averaging period or 2160 for a 90-group boiler operating day averaging period),

Ter_k = Emissions rate (lb/MMBTU or lb/MWh) from the most recent test of EGU k,

Rmt_k = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU k,

r_k = hours in an averaging period for EGU k (*e.g.,* 720 for a 30-group boiler operating day averaging period or 2160 for a 90-group boiler operating day averaging period), and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum_{j=1}^{p}\left[\left(\sum_{i=1}^{n} Herm_{i,j}\right) \times Smm_j \times Cfm_j \times q_j\right] + \sum_{k=1}^{m} Ter_k \times Smt_k \times Cft_k \times r_k}{\sum_{j=1}^{p}\left[\sum_{i=1}^{n} Smm_j \times Cfm_j \times q_j\right] + \sum_{k=1}^{m} Smt_k \times Cft_k \times r_k} \quad (Eq.\ 1b)$$

Where:

Variables with the similar names share the descriptions for Equation 1a,

Smm_j = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = conversion factor, calculated from the most recent compliance test results, in terms units of heat input or electrical output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = conversion factor, calculated from the most recent compliance test results, in terms units of heat input or electrical output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

(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 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 hours that hourly rates are 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 output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

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

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross 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 output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the ''coal-fired unit not low rank virgin coal'' subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

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

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross 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 hours that hourly rates are 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 output,

Rt_i = Total heat input or gross output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

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

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross 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 output per pound of steam generated, from unit i that uses emissions testing.

* * * * *

(f) Emissions averaging group eligibility demonstration. You must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to paragraph (f)(1) or (2) of this section using the maximum possible heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing your emissions averaging plan, you must conduct required emissions monitoring for 30- (or 90-) days of boiler operation and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with this section. Should the Administrator require approval, you must submit your proposed emissions averaging plan and supporting data at least 120 days before the date on which you plan to being using emissions averaging. If the Administrator requires approval of your plan, you may not begin using emissions averaging until the Administrator approves your plan.

* * * * *

(2) If you are not capable of monitoring heat input or gross output, and the EGU generates steam for purposes other than generating electricity, you may use Equation 1b of this section as an alternative to using Equation 1a of this section to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 to this subpart.

* * * * *

(g) * * *

(1) You must use Equation 2a or 3a of paragraph (b) of this section to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input or gross output, you may use Equation 2b or 3b of paragraph (b) of this section as an alternative to using Equation 2a of paragraph (b) of this section to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option.

* * * * *

(j) * * *

(1) * * *

(ii) The process weighting parameter (heat input, gross output, or steam generated) that will be monitored for each averaging group;

* * * * *

■ 11. Section 63.10010 is amended by:

■ a. Revising paragraph (a)(4);

■ b. Revising paragraph (f)(3);

■ c. Revising paragraphs (h)(6)(i) and (ii);

■ d. Revising paragraphs (i)(5)(i)(A) and (B);

■ e. Revising paragraph (j)(1)(i) and (j)(4)(i)(A) and (B); and

■ f. Revising paragraph (l).

The revisions read as follows:

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

* * * * *

(a) * * *

(4) *Unit with a main stack and a bypass stack that exhausts to the atmosphere independent of the main stack.* If the exhaust configuration of an affected unit consists of a main stack and a bypass stack, you shall install CEMS on both the main stack and the bypass stack. If it is not feasible to certify and quality-assure the data from a monitoring system on the bypass stack, you shall:

(i) Route the exhaust from the bypass through the main stack and its monitoring so that bypass emissions are measured, or

(ii) Install a CEMS only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements.

* * * * *

(f) * * *

(3) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the preceding 30 boiler operating days.

* * * * *

(h) * * *

(6) * * *

(i) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions. You must report any such periods in your annual deviation report;

(ii) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report.

* * * * *

(i) * * *

(5) * * *

(i) * * *

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions. You must report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report.

* * * * *

(j) * * *

(1) * * *

(i) Install, calibrate, operate, and maintain your HAP metals CEMS according to your CMS quality control program, as described in § 63.8(d)(2). 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.

* * * * *

(4) * * *

(i) * * *

(A) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities conducted during monitoring system malfunctions. You must report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities conducted during out-of-control periods. You must report any such periods in your annual deviation report.

* * * * *

(l) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, you must install, verify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with § 63.10020(e).

(1) You shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods.

(2) You shall submit the site-specific monitoring plan upon request by the Administrator.

(3) The provisions of the monitoring plan must address the following items:

(i) Monitoring system installation;

(ii) Performance and equipment specifications;

(iii) Schedule for initial and periodic performance evaluations;

(iv) Performance evaluation procedures and acceptance criteria;

(v) On-going operation and maintenance procedures; and

(vi) On-going recordkeeping and reporting procedures.

(4) You may rely on monitoring system specifications or instructions or manufacturer's specifications to address paragraphs (l)(3)(i) through (vi) of this section.

(5) You must operate and maintain the monitoring system according to the site-specific monitoring plan.

■ 12. Section 63.10011 is amended by revising paragraphs (b), (c), (e) and (g) to read as follows:

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

* * * * *

(b) If you are subject to an operating limit in Table 4 to this subpart, you demonstrate initial compliance with HAP metals or filterable PM emission limit(s) through performance stack tests and you elect to use a PM CPMS to demonstrate continuous performance, or if, for a liquid oil-fired EGU, and you use quarterly stack testing for HCl and HF plus site-specific parameter monitoring to demonstrate continuous performance, you must also establish a site-specific operating limit, in accordance with § 63.10007 and Table 6 to this subpart. You may use only the parametric data recorded during successful performance tests (*i.e.,* tests that demonstrate compliance with the applicable emissions limits) to establish an operating limit.

(c)(1) If you use CEMS or sorbent trap monitoring systems to measure a HAP (*e.g.,* Hg or HCl) directly, the initial performance test, consisting of a 30-boiler operating day (or, for certain coal-fired, existing EGUs that use emissions averaging for Hg, a 90-boiler operating day) rolling average emissions rate obtained with certified CEMS, expressed in units of the standard, may occur on or before the first averaging period after the date that compliance with the subpart is required but must occur such that the averaging period is completed on or before the date that compliance must be demonstrated. Initial compliance is demonstrated if the results of the performance test meet the applicable emission limit in Table 1 or 2 to this subpart.

(2) For an EGU that uses a CEMS to measure SO_2 or PM emission for initial compliance, the initial performance test, consisting of a 30-boiler operating day average emission rate obtained with certified CEMS, expressed in units of the standard, may occur on or before the first averaging period after the date that compliance with the subpart is required but must occur such that the averaging period is completed on or before the date that compliance must be demonstrated. Initial compliance is demonstrated if the results of the performance test meet the applicable SO_2 or PM emission limit in Table 1 or 2 to this subpart.

* * * * *

(e) You must submit a Notification of Compliance Status containing the results of the initial compliance demonstration, in accordance with § 63.10030(e).

* * * * *

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

(1) You may use the diluent cap and default electrical load values, as described in § 63.10007(f), during startup periods or shutdown periods.

(2) You must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods.

(3) You must report the information as required in § 63.10031.

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

(i) As mentioned in § 63.6(g)(1), the request will be published in the **Federal Register** for notice and comment rulemaking. Until promulgation in the **Federal Register** of the final alternative non-opacity emission standard, you shall comply with paragraph (1) of the definition of ''startup'' in § 63.10042. You shall not implement the alternative non-opacity emissions standard until promulgation in the **Federal Register** of the final alternative non-opacity emission standard.

(ii) The request need not address the items contained in § 63.6(g)(2).

(iii) The request shall provide evidence of a documented manufacturer-identified safety issue.

(iv) The request shall provide information to document that the PM control device is adequately designed and sized to meet the PM emission limit applicable to the EGU.

(v) In addition, the request shall contain documentation that:

(A) The EGU is using clean fuels to the maximum extent practicable, taking into account considerations such as not compromising boiler or control device integrity, to bring the EGU and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel in the EGU;

(B) The EGU has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(vi) The request shall specify the other work practice standards the EGU owner or operator will take to limit HAP emissions during startup periods and shutdown periods to ensure a control level consistent with the work practice standards of the final rule.

(vii) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

■ 13. Section 63.10020 is amended by revising paragraph (e) to read as follows:

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

* * * * *

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

(1) During each period of startup, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of startup begins;

(ii) The quantity and heat input of clean fuel for each hour of startup;

(iii) The gross output for each hour of startup;

(iv) The date and time that non-clean fuel combustion begins; and

(v) The date and time that clean fuels being combusted for the purpose of startup ends.

(2) During each period of shutdown, you must record for each EGU:

(i) The date and time that clean fuels being combusted for the purpose of shutdown begins;

(ii) The quantity and heat input of clean fuel for each hour of shutdown;

(iii) The gross output for each hour of shutdown;

(iv) The date and time that non-clean fuel combustion ends; and

(v) The date and time that clean fuels being combusted for the purpose of shutdown ends.

(3) For PM or non-mercury HAP metals work practice monitoring during startup periods, you must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.10010(l).

(i) Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit or that has LEE status for filterable PM or total non-Hg HAP metals for non-liquid oil-fired EGUs (or HAP metals emissions for liquid oil-fired EGUs), or individual non-mercury metals CEMS you must:

(A) Record temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s), upstream of the filterable PM control devices during each hour of startup.

(B) Record temperature and flow of exhaust gas, as well as amperage of any induced draft fan(s), downstream of the filterable PM control devices during each hour of startup.

(C) For an EGU with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(D) For an EGU with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(E) For an EGU with a wet scrubber needed for filterable PM control, record the scrubber liquid to flue gas ratio and the differential pressure across the scrubber of the liquid during each hour of startup.

■ 14. Section 63.10021 is amended by revising paragraphs (d)(3), (e) introductory text, and (e)(9)(i) and (ii) to read as follows:

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

* * * * *

(d) * * *

(3) Must conduct site-specific monitoring using CMS to demonstrate compliance with the site-specific monitoring requirements in Table 7 to this subpart pertaining to HCl and HF emissions from a liquid oil-fired EGU to ensure compliance with the HCl and HF emission limits in Tables 1 and 2 to this subpart, in accordance with the requirements of § 63.10000(c)(2)(iii). The monitoring must meet the general operating requirements provided in § 63.10020.

(e) Conduct periodic performance tune-ups of your EGU(s), as specified in paragraphs (e)(1) through (9) of this section. For your first tune-up, you may delay the burner inspection until the next scheduled EGU outage provided you meet the requirements of § 63.10005. Subsequently, you must perform an inspection of the burner at least once every 36 calendar months unless your EGU employs neural network combustion optimization during normal operations in which case you must perform an inspection of the burner and combustion controls at least once every 48 calendar months.

* * * * *

(9) * * *

(i) If the first tune-up is performed prior to April 16, 2015, report the date of the tune-up in hard copy (as specified in § 63.10030) and electronically (as specified in § 63.10031). Report the date of each subsequent tune-up electronically (as specified in § 63.10031).

(ii) If the first tune-up is performed on or after April 16, 2015, report the date of the tune-up and all subsequent tune-ups electronically, in accordance with § 63.10031.

* * * * *

■ 15. Section 63.10023 is amended by removing and reserving paragraph (b)(1) and revising (b)(2) introductory text to read as follows:

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

* * * * *

(b) * * *

(2) Determine your operating limit as follows:

* * * * *

■ 16. Section 63.10030 is amended by:

■ a. Revising paragraphs (e)(1) and (e)(7)(i);

■ b. Adding paragraph (e)(7)(iii);

■ c. Revising paragraph (e)(8);

■ d. Adding paragraph (f).

The revisions and additions read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(e) * * *

(1) A description of the affected source(s), including identification of the subcategory of the source, the design capacity of the source, a description of the add-on controls used on the source, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of 40 CFR 241.3, and justification for the selection of fuel(s) burned during the performance test.

* * * * *

(7) * * *

(i) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting stack tests once every 3 years consistent with § 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level you achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in § 63.10006(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions.

* * * * *

(iii) For each of your existing EGUs, identification of each emissions limit as specified in Table 2 to this subpart with which you plan to comply.

(A) You may switch between mass per heat input and mass per gross output levels, provided:

(*1*) You submit a Notification of Compliance Status that identifies for each EGU or EGU emissions averaging group involved in proposed switch both the current and proposed emission limit;

(*2*) Your submission arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur;

(*3*) Your submission demonstrates through performance stack test results conducted within 30 days prior to your submission, compliance for each EGU or EGU emissions averaging group with both the mass per heat input and mass per electric output limits;

(*4*) You revise and submit all other applicable plans, *e.g.,* monitoring and emissions averaging, with your submission; and

(*5*) You maintain records of all information regarding your choice of emission limits.

(B) You may begin to use the revised emission limits the semi-annual reporting period after receipt of written acknowledgement from the Administrator of the switch.

(C) From submission until the semi-annual reporting period after receipt of written acknowledgement from the Administrator of the switch, you must demonstrate compliance with both the mass per heat input and mass per electric output emission limits for each pollutant for each EGU or EGU emissions averaging group.

(8) Identification of whether you plan to rely on paragraph (1) or (2) of the definition of ''startup'' in § 63.10042.

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

(A) The original EGU installation date;

(B) The original EGU design characteristics, including, but not limited to, fuel mix and PM controls;

(C) Each design PM control device efficiency established during performance testing or while operating in periods other than startup and shutdown periods;

(D) The design PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds PM per hour established during performance testing or while operating in periods other than startup and shutdown periods;

(E) The design time from start of fuel combustion to necessary conditions for each PM control device startup;

(F) Each design PM control device efficiency upon startup of the PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(G) Current EGU PM producing characteristics, including, but not limited to, fuel mix and PM controls, if different from the characteristics provided in paragraph (e)(8)(i)(B) of this section;

(H) Current PM control device efficiency from each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(C) of this section;

(I) Current PM emission rate from the EGU in terms of pounds PM per MMBtu and pounds per hour, if different from the rate provided in paragraph (e)(8)(i)(D) of this section;

(J) Current time from start of fuel combustion to conditions necessary for each PM control device startup, if different from the time provided in paragraph (e)(8)(i)(E) of this section; and

(M) Current PM control device efficiency upon startup of each PM control device, if different from the efficiency provided in paragraph (e)(8)(i)(H) of this section.

(ii) The report shall be prepared, signed, and sealed by a professional engineer licensed in the state where your EGU is located.

(f) You must submit the notifications in § 63.10000(h)(2) and (i)(2) that may apply to you by the dates specified.

■ 17. Section 63.10031 is amended by:

■ a. Revising paragraphs (c)(4) and (5);

■ b. Adding paragraph (c)(6); and

■ c. Revising paragraph (f)(5).

The revisions and addition read as follows:

§ 63.10031 What reports must I submit and when?

* * * * *

(c) * * *

(4) Include the date of the most recent tune-up for each EGU. For the first tune-up, include the date of the burner inspection if it was delayed.

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

(i) Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of § 63.10032(f).

(ii) Include the information required to be monitored, collected, or recorded according to the requirements of § 63.10020(e).

(iii) If you choose to use CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or SO_2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values.

(iv) If you choose to use a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter.

(v) If you choose to use a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation.

(6) Emergency bypass reports from EGUs with LEE status.

* * * * *

(f) * * *

(5) All reports required by this subpart not subject to the requirements in paragraphs (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)(1) through (4) of this section in paper format.

* * * * *

■ 18. Section 63.10032 is amended by revising paragraph (f) to read as follows:

§ 63.10032 What records must I keep?

* * * * *

(f) Regarding startup periods or shutdown periods:

(1) Should you choose to rely on paragraph (1) of the definition of ''startup'' in § 63.10042 for your EGU, you must keep records of the occurrence and duration of each startup or shutdown.

(2) Should you choose to rely on paragraph (2) of the definition of ''startup'' in § 63.10042 for your EGU, you must keep records of:

(i) The determination of the maximum clean fuel capacity for each EGU;

(ii) The determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU; and

(iii) The information required in § 63.10020(e).

* * * * *

■ 19. Section 63.10042 is amended by:

■ a. Revising the definitions of ''Coal-fired electric utility steam generating unit,'' ''Coal refuse,'' ''Fossil fuel-fired,'' ''Integrated gasification combined cycle electric utility steam generating unit or IGCC,'' ''Limited-use liquid oil-fired subcategory,'' and ''Natural gas-fired electric utility steam generating unit'';

■ b. Adding, in alphabetical order, a definition of ''Neural network or neural net''; and

■ c. Revising the definition of ''Oil-fired electric utility steam generating unit.''

The revisions and additions read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

* * * * *

Fossil fuel-fired means an electric utility steam generating unit (EGU) that is capable of combusting more than 25 MW of fossil fuels. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (*e.g.,* coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired means any EGU that fired fossil fuels for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC* means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years in a combined-cycle gas turbine. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

* * * * *

Limited-use liquid oil-fired subcategory means an oil-fired electric utility steam generating unit with an annual capacity factor when burning oil of less than 8 percent of its maximum or nameplate heat input, whichever is greater, averaged over a 24-month block contiguous period commencing April 16, 2015.

* * * * *

Natural gas-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired, oil-fired, or IGCC electric utility steam generating unit and that burns natural gas for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years. EGU owners and operators must estimate coal, oil, and natural gas usage for the first 3 calendar years after the applicable compliance date and they are solely responsible for assuring compliance with this final rule or other applicable standard based on their fuel usage projections.

* * * * *

Neural network or *neural net* for purposes of this rule means an automated boiler optimization system. A neural network typically has the ability to process data from many inputs to develop, remember, update, and enable algorithms for efficient boiler operation.

* * * * *

Oil-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired electric utility steam generating unit and that burns oil for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in § 63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years.

* * * * *

■ 20. Revise Table 1 to subpart UUUUU of part 63 to read as follows:

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

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
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	

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

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR Total non-Hg HAP metals	OR 6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E–2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[4] 9.0E–2 lb/MWh[5]	Collect a minimum of 1 dscm per run.
	OR Total non-Hg HAP metals	OR 4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 2 dscm per run.
	Antimony (Sb)	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.	

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

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR Individual HAP metals:	OR Collect a minimum of 2 dscm per run.	
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR Total HAP metals	OR 7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR Individual HAP metals:	OR	Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	

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

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	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).	3.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

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

■ 21. Revise Table 2 to subpart UUUUU of part 63 to read as follows:

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
		OR	
		1.0E0 lb/TBtu or 1.1E–2 lb/GWh	LEE Testing for 90 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired unit low rank virgin coal.	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	5.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	8.0E–1 lb/TBtu or 8.0E–3 lb/GWh.	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E–2 lb/GWh.	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 2.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR		

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Sulfur dioxide (SO_2) [4]	2.0E–1 lb/MMBtu or 1.5E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	4.0E0 lb/TBtu or 4.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	4.0E–2 lb/MMBtu or 4.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–5 lb/MMBtu or 5.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.4E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	1.5E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–1 lb/TBtu or 1.0E–3 lb/GWh.	
	Cadmium (Cd)	1.5E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	2.9E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Cobalt (Co)	1.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	1.9E+2 lb/TBtu or 1.8E0 lb/GWh.	
	Manganese (Mn)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Nickel (Ni)	6.5E0 lb/TBtu or 7.0E–2 lb/GWh.	
	Selenium (Se)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–4 lb/MMBtu or 5.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Mercury (Hg)	2.5E0 lb/TBtu or 3.0E–2 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	8.0E–4 lb/MMBtu or 8.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 1 dscm per run.
	Antimony (Sb)	1.3E+1 lb/TBtu or 2.0E–1 lb/GWh.	
	Arsenic (As)	2.8E0 lb/TBtu or 3.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 2.0E–3 lb/GWh.	
	Chromium (Cr)	5.5E0 lb/TBtu or 6.0E–2 lb/GWh.	
	Cobalt (Co)	2.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Lead (Pb)	8.1E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.2E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	1.1E+2 lb/TBtu or 1.1E0 lb/GWh.	
	Selenium (Se)	3.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MMBtu or 1.0E–2 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run.

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUs—Continued

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
			For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MMBtu or 4.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–2 lb/MMBtu or 3.0E–1 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	6.0E–4 lb/MMBtu or 7.0E–3 lb/MWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.2E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Arsenic (As)	4.3E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Beryllium (Be)	6.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 3.0E–3 lb/GWh.	
	Chromium (Cr)	3.1E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Cobalt (Co)	1.1E+2 lb/TBtu or 1.4E0 lb/GWh.	
	Lead (Pb)	4.9E0 lb/TBtu or 8.0E–2 lb/GWh.	
	Manganese (Mn)	2.0E+1 lb/TBtu or 3.0E–1 lb/GWh.	
	Nickel (Ni)	4.7E+2 lb/TBtu or 4.1E0 lb/GWh.	
	Selenium (Se)	9.8E0 lb/TBtu or 2.0E–1 lb/GWh.	
	Mercury (Hg)	4.0E–2 lb/TBtu or 4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be <½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–4 lb/MMBtu or 2.0E–3 lb/MWh.	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
	c. Hydrogen fluoride (HF)	6.0E–5 lb/MMBtu or 5.0E–4 lb/MWh.	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 2 hours.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	8.0E–3 lb/MMBtu or 9.0E–2 lb/MWh [2].	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–5 lb/MMBtu or 6.0E–1 lb/GWh.	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–1 lb/TBtu or 7.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–1 lb/TBtu or 5.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–2 lb/TBtu or 5.0E–4 lb/GWh.	
	Cadmium (Cd)	3.0E–1 lb/TBtu or 4.0E–3 lb/GWh.	
	Chromium (Cr)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Cobalt (Co)	1.1E0 lb/TBtu or 2.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–1 lb/TBtu or 2.0E–2 lb/GWh.	
	Manganese (Mn)	2.3E0 lb/TBtu or 4.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E0 lb/TBtu or 2.0E–1 lb/GWh.	

TABLE 2 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR EXISTING EGUS—Continued

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

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5 to Subpart UUUUU of Part 63—Performance Testing Requirements . . .
	Selenium (Se)	1.2E0 lb/Tbtu or 2.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	5.0E–3 lb/MMBtu or 8.0E–2 lb/MWh.	For Method 26A, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03 [3] or Method 320, sample for a minimum of 1 hour.
	OR Sulfur dioxide (SO_2) [4]	3.0E–1 lb/MMBtu or 2.0E0 lb/MWh.	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–1 lb/TBtu or 2.0E–3 lb/GWh	LEE Testing for 30 days with 10 days maximum per Method 30B run or Hg CEMS or Sorbent trap monitoring system only.

[1] For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
[2] Gross output.
[3] Incorporated by reference, see § 63.14.
[4] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

■ 22. Revise Table 3 to subpart UUUUU of part 63 to read as follows:

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS

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

If your EGU is . . .	You must meet the following . . .
1. An existing EGU	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
2. A new or reconstructed EGU.	Conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in § 63.10021(e).
3. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during startup.	You have the option of complying using either of the following work practice standards: (1) If you choose to comply using paragraph (1) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, you must use clean fuels as defined in § 63.10042 for ignition. Once you convert to firing coal, residual oil, or solid oil-derived fuel, you must engage all of the applicable control technologies except dry scrubber and SCR. You must start your dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. You must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this subpart. You must keep records during startup periods. You must provide reports concerning activities and startup periods, as specified in § 63.10011(g) and § 63.10021(h) and (i). (2) If you choose to comply using paragraph (2) of the definition of "startup" in § 63.10042, you must operate all CMS during startup. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of startup. For startup of an EGU, you must use one or a combination of the clean fuels defined in § 63.10042 to the maximum extent practicable, taking into account considerations such as boiler or control device integrity, throughout the startup period. You must have sufficient clean fuel capacity to engage and operate your PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. You must meet the startup period work practice requirements as identified in § 63.10020(e). Once you start firing coal, residual oil, or solid oil-derived fuel, you must vent emissions to the main stack(s). You must comply with the applicable emission limits within 4 hours of start of electricity generation. You must engage and operate your particulate matter control(s) within 1 hour of first firing of coal, residual oil, or solid oil-derived fuel. You must start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart that require operation of the control devices.

TABLE 3 TO SUBPART UUUUU OF PART 63—WORK PRACTICE STANDARDS—Continued

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

If your EGU is . . .	You must meet the following . . .
	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 collect monitoring data during startup periods, as specified in § 63.10020(a) and (e). You must keep records during startup periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. You must provide reports concerning activities and startup periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.
4. A coal-fired, liquid oil-fired (excluding limited-use liquid oil-fired subcategory units), or solid oil-derived fuel-fired EGU during shutdown.	You must operate all CMS during shutdown. You must also collect appropriate data, and you must calculate the pollutant emission rate for each hour of shutdown. While firing coal, residual oil, or solid oil-derived fuel during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, you must operate your controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than this Subpart and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in § 63.10042 and must be used to the maximum extent practicable. 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 periods and shutdown periods at which time you must meet this work practice. You must collect monitoring data during shutdown periods, as specified in § 63.10020(a). You must keep records during shutdown periods, as provided in §§ 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. You must provide reports concerning activities and shutdown periods, as specified in §§ 63.10011(g), 63.10021(i), and 63.10031.

■ 23. 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 . . .
PM CPMS	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 24. Revise Table 5 to subpart UUUUU of part 63 to read as follows:

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

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

To conduct a performance test for the following pollutant ...	Using...	You must perform the following activities, as applicable to your input- or output-based emission limit ...	Using ...[2]
1. Filterable Particulate matter (PM)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A-1 to Part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to Part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A-2 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter.
		e. Measure the filterable PM concentration.	Method 5 at Appendix A-3 to Part 60 of this chapter. When using Method 5, use the average of the final 2 filter weightings.
			For positive pressure fabric filters, Method 5D at Appendix A-3 to Part 60 of this chapter for filterable PM emissions.
			Note that the Method 5 front half temperature shall be 160° ± 14°C (320° ± 25°F).
		f. Convert emissions concentration to lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	PM CEMS	a. Install, certify, operate, and maintain the PM CEMS.	Performance Specification 11 at Appendix B to Part 60 of this chapter and Procedure 2 at Appendix F to Part 60 of this chapter.
		b. Install, certify, operate, and maintain the diluent gas,	Part 75 of this chapter and §§ 63.10010 (a), (b), (c), and (d).

		flow rate, and/or moisture monitoring systems.	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
2. Total or individual non-Hg HAP metals	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A-1 to Part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to Part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A-2 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter.
		e. Measure the HAP metals emissions concentrations and determine each individual HAP metals emissions concentration, as well as the total filterable HAP metals emissions concentration and total HAP metals emissions concentration.	Method 29 at Appendix A-8 to Part 60 of this chapter. For liquid oil-fired units, Hg is included in HAP metals and you may use Method 29, Method 30B at Appendix A-8 to Part 60 of this chapter; for Method 29, you must report the front half and back half results separately. When using Method 29, report metals matrix spike and recovery levels.
		f. Convert emissions concentrations (individual HAP metals, total filterable HAP metals, and total HAP metals) to lb/MMBtu or lb/MWh emissions	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

		rates.	
3. Hydrogen chloride (HCl) and hydrogen fluoride (HF)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A-1 to Part 60 of this chapter.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to Part 60 of this chapter.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A-2 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter.
		e. Measure the HCl and HF emissions concentrations.	Method 26 or Method 26A at Appendix A-8 to Part 60 of this chapter or Method 320 at Appendix A to Part 63 of this chapter or ASTM 6348-03[3] with (1) the following conditions using ASTM D6348-03: (A) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; (B) For ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent

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

		operate, and maintain the diluent gas, flow rate, and/or moisture monitoring systems.	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
4. Mercury (Hg)	Emissions Testing	a. Select sampling ports location and the number of traverse points.	Method 1 at Appendix A-1 to Part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G or 2H at Appendix A-1 or A-2 to Part 60 of this chapter.
		c. Determine oxygen and carbon dioxide	Method 3A or 3B at Appendix A-1 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[3]

		concentrations of the stack gas.	
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter.
		e. Measure the Hg emission concentration.	Method 30B at Appendix A-8 to Part 60 of this chapter, ASTM D6784[3], or Method 29 at Appendix A-8 to Part 60 of this chapter; for Method 29, you must report the front half and back half results separately.
		f. Convert emissions concentration to lb/TBtu or lb/GWh emission rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
	OR	OR	
	Hg CEMS	a. Install, certify, operate, and maintain the CEMS.	Sections 3.2.1 and 5.1 of Appendix A of this subpart.
		b. Install, certify, operate, and maintain the diluent gas,	Part 75 of this chapter and §§ 63.10010 (a), (b), (c), and (d).

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

		c. Convert emissions concentrations to 30 boiler operating day rolling average lb/TBtu or lb/GWh emissions rates.	Section 6 of Appendix A to this subpart.
	OR	OR	
	LEE testing	a. Select sampling ports location and the number of traverse points.	Single point located at the 10% centroidal area of the duct at a port location per Method 1 at Appendix A-1 to Part 60 of this chapter or Method 30B at Appendix A-8 for Method 30B point selection.
		b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2A, 2C, 2F, 2G, or 2H at Appendix A-1 or A-2 to Part 60 of this chapter or flow monitoring system certified per Appendix A of this subpart.
		c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B at Appendix A-1 to Part 60 of this chapter, or ANSI/ASME PTC 19.10-1981,[3] or diluent gas monitoring systems certified according to Part 75 of this chapter.
		d. Measure the moisture content of the stack gas.	Method 4 at Appendix A-3 to Part 60 of this chapter, or moisture monitoring systems certified according to Part 75 of this chapter.

		e. Measure the Hg emission concentration.	Method 30B at Appendix A-8 to Part 60 of this chapter; perform a 30 operating day test, with a maximum of 10 operating days per run (i.e., per pair of sorbent traps) or sorbent trap monitoring system or Hg CEMS certified per Appendix A of this subpart.
		f. Convert emissions concentrations from the LEE test to lb/TBtu or lb/GWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).
		g. Convert average lb/TBtu or lb/GWh Hg emission rate to lb/year, if you are attempting to meet the 29.0 lb/year threshold.	Potential maximum annual heat input in TBtu or potential maximum electricity generated in GWh.
5. Sulfur dioxide (SO_2)	SO_2 CEMS	a. Install, certify, operate, and maintain the CEMS.	Part 75 of this chapter and §§ 63.10010 (a) and (f).
		b. Install, operate, and maintain the	Part 75 of this chapter and §§ 63.10010 (a), (b), (c), and (d).

		diluent gas, flow rate, and/or moisture monitoring systems.	
		c. Convert hourly emissions concentrations to 30 boiler operating day rolling average lb/MMBtu or lb/MWh emissions rates.	Method 19 F-factor methodology at Appendix A-7 to Part 60 of this chapter, or calculate using mass emissions rate and electrical output data (see § 63.10007(e)).

[1] Regarding emissions data collected during periods of startup or shutdown, see §§ 63.10020(b) and (c) and 63.10021(h).
[2] See Tables 1 and 2 to this subpart for required sample volumes and/or sampling run times.
[3] Incorporated by reference, see § 63.14.

■ 25. 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 . . .
Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 26. Revise Table 8 to subpart UUUUU of part 63 to read as follows:

TABLE 8 TO SUBPART UUUUU OF PART 63—REPORTING REQUIREMENTS

[As stated in § 63.10031, you must comply with the following requirements for reports:]

You must submit a	The report must contain . . .	You must submit the report . . .
1. Compliance report.	a. Information required in § 63.10031(c)(1) through (6); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in § 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in § 63.8(c)(7), the report must contain the information in § 63.10031(e).	Semiannually according to the requirements in § 63.10031(b).

■ 27. Revise Table 9 to subpart UUUUU of part 63 to read as follows:

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU—Continued

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following:]

Citation	Subject	Applies to subpart UUUUU
§ 63.6(a), (b)(1) through (5), (b)(7), (c), (f)(2) and (3), (h)(2) through (9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(g)	Compliance with Standards and Maintenance Requirements, Use of an alternative non-opacity emission standard.	Yes. See §§ 63.10011(g)(4) and 63.10021(h)(4) for additional requirements.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes, except for the 60-day notification prior to conducting a performance test in § 63.9(d); instead use a 30-day notification period per § 63.10030(d).
§ 63.10(a), (b)(1), (c), (d)(1) and—(2), (e), and (f).	Recordkeeping and Reporting Requirements	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) through—(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3),and (d)(3) through—(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See § 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See § 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§§ 63.13 through—63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§§ 63.1(a)(5),(a)(7) through—(9), (b)(2), (c)(3) and—(4), (d), 63.6(b)(6), (c)(3) and), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2) through—(4), (c)(9).	Reserved	No.

■ 28. Appendix A to subpart UUUUU of part 63 is amended by:

■ a. Revising paragraph 3.2.1.2.1;

■ b. Revising paragraphs 4.1.1.1, 4.1.1.3, 4.1.1.5, and 4.1.1.5.2;

■ c. Revising Tables A–1 and A–2;

■ d. Revising paragraphs 5.1.2.1, 5.1.2.3, and 5.2.1; and

■ e. Adding paragraph 6.2.2.3 and 7.1.2.6.

The revisions and additions to read as follows:

Appendix A to Subpart UUUUU of Part 63—Hg Monitoring Provisions

* * * * *

3. Mercury Emissions Measurement Methods

* * * * *

3.2.1.2.1 *NIST Traceability.* Only NIST-certified or NIST-traceable calibration gas standards and reagents (as defined in paragraphs 3.1.4 and 3.1.5 of this appendix), and including, but not limited to, Hg gas generators and Hg gas cylinders, shall be used for the tests and procedures required under this subpart. Calibration gases with known concentrations of Hg^0 and $HgCl_2$ are required. Special reagents and equipment may be needed to prepare the Hg^0 and $HgCl_2$ gas standards (*e.g.,* NIST-traceable solutions of $HgCl_2$ and gas generators equipped with mass flow controllers).

* * * * *

4. Certification and Recertification Requirements

* * * * *

4.1.1.1 *7-Day Calibration Error Test.* Perform the 7-day calibration error test on 7 consecutive source operating days, using a zero-level gas and either a high-level or a mid-level calibration gas standard (as defined in sections 3.1.8, 3.1.10, and 3.1.11 of this appendix). Use a NIST-traceable elemental Hg gas standard (as defined in section 3.1.4 of this appendix) for the test. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Operate the Hg CEMS in its normal sampling mode during the test. The calibrations should be approximately 24 hours apart, unless the 7-day test is performed over non-consecutive calendar days. On each day of the test, inject the zero-level and upscale gases in sequence and record the analyzer responses. Pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and through as much of the sampling probe as is practical. Do not make any manual adjustments to the monitor (*i.e.,* resetting the calibration) until after taking measurements at both the zero and upscale concentration levels. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined, and use only the unadjusted analyzer responses in the calculations. Calculate the calibration error (CE) on each day of the test, as described in Table A–1 of this appendix. The CE on each day of the test must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

* * * * *

4.1.1.3 *Three-Level System Integrity Check.* Perform the 3-level system integrity check using low, mid, and high-level calibration gas concentrations generated by a NIST-traceable source of oxidized Hg. Follow the same basic procedure as for the linearity check. If moisture and/or chlorine is added to the calibration gas, the dilution effect of the moisture and/or chlorine addition on the calibration gas concentration must be accounted for in an appropriate manner. Calculate the system integrity error (SIE), as described in Table A–1 of this appendix. The SIE must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

* * * * *

4.1.1.5 *Relative Accuracy Test Audit (RATA).* Perform the RATA of the Hg CEMS at normal load. Acceptable Hg reference methods for the RATA include ASTM D6784–02 (Reapproved 2008), ‘‘Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)’’ (incorporated by reference, see § 63.14) and Methods 29, 30A, and 30B in appendix A–8 to part 60 of this chapter. When Method 29 or ASTM D6784–02 is used, paired sampling trains are required and the filterable portion of the sample need not be included when making comparisons to the Hg CEMS results for purposes of a RATA. To validate a Method 29 or ASTM D6784–02 test run, calculate the relative deviation (RD) using Equation A–1 of this section, and assess the results as follows to validate the run. The RD must not exceed 10 percent, when the average Hg concentration is greater than 1.0 µg/dscm. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

$$RD = \frac{|C_a + C_b|}{C_a + C_b} \times 100 \quad (Eq.\ A-1)$$

Where:

RD = Relative Deviation between the Hg concentrations of samples ‘‘a’’ and ‘‘b’’ (percent),

C_a = Hg concentration of Hg sample ‘‘a’’ (µg/dscm), and

C_b = Hg concentration of Hg sample ‘‘b’’ (µg/dscm).

* * * * *

4.1.1.5.2 *Calculation of RATA Results.* Calculate the relative accuracy (RA) of the monitoring system, on a µg/scm basis, as described in section 12 of Performance Specification (PS) 2 in Appendix B to part 60 of this chapter (see Equations 2–3 through 2–6 of PS2) including the option to substitute the emission limit value (in this case the equivalent concentration) in the denominator of Equation 2–6 in place of the average RM value when the average emissions for the test are less than 50 percent of the applicable emissions limit. For purposes of calculating the relative accuracy, ensure that the reference method and monitoring system data are on a consistent basis, either wet or dry. The CEMS must either meet the main performance specification or the alternative specification in Table A–1 of this appendix.

* * * * *

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR Hg CEMS

For this required certification test . . .	The main performance specification [1] is . . .	The alternate performance specification [1] is . . .	And the conditions of the alternate specification are . . .
7-day calibration error test [2]	$\lvert R - A \rvert \leq 5.0\%$ of span value, for both the zero and upscale gases, on each of the 7 days.	$\lvert R - A \rvert \leq 1.0$ µg/scm	The alternate specification may be used on any day of the test.
Linearity check [3]	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas concentration at each calibration gas level (low, mid, or high).	$\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
3-level system integrity check [4]	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas concentration at each calibration gas level.	$\lvert R - A_{avg} \rvert \leq 0.8$ µg/scm	The alternate specification may be used at any gas level.
RATA	20.0% RA	≤10% RA when concentration equivalent of applicable emissions limit is used in place of RM_{avg} in Equation 2–6 of PS2 (see Section 4.1.1.5.2 of this appendix).	RM_{avg} <50% of applicable emissions limit.

TABLE A–1—REQUIRED CERTIFICATION TESTS AND PERFORMANCE SPECIFICATIONS FOR Hg CEMS—Continued

For this required certification test . . .	The main performance specification [1] is . . .	The alternate performance specification [1] is . . .	And the conditions of the alternate specification are . . .
Cycle time test [2]	15 minutes where the stability criteria are readings change by <2.0% of span *or* by ≤0.5 μg/scm, for 2 minutes.		

[1] Note that \|R − A\| is the absolute value of the difference between the reference gas value and the analyzer reading. $|R - A_{avg}|$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.
[2] Use elemental Hg standards; a mid-level or high-level upscale gas may be used. The cycle time test is not required for Hg CEMS that use integrated batch sampling; however, those monitors must be capable of recording at least one Hg concentration reading every 15 minutes.
[3] Use elemental Hg standards.
[4] Use oxidized Hg standards.

* * * * *

5. Ongoing Quality Assurance (QA) and Data Validation

* * * * *

TABLE A–2—ON-GOING QA TEST REQUIREMENTS FOR Hg CEMS

Perform this type of QA test . . .	At this frequency . . .	With these qualifications and exceptions . . .	Acceptance criteria . . .
Calibration error test	Daily	• Use either a mid- or high-level gas. • Use elemental Hg • Calibrations are not required when the unit is not in operation.	|R − A| ≤5.0% of span value *or* |R − A| ≤1.0 μg/scm.
Single-level system integrity check	Weekly [1]	• Use oxidized Hg—either mid- or high-level.	$|Rn - A_{avg}|$ ≤10.0% of the reference gas value *or* $|R - A_{avg}|$ ≤0.8 μg/scm.
Linearity check *or* 3-level system integrity check.	Quarterly [3]	• Required in each "QA operating quarter" [2] and no less than once every 4 calendar quarters. • 168 operating hour grace period available. • Use elemental Hg for linearity check. • Use oxidized Hg for system integrity check.	$|R - A_{avg}|$ ≤10.0% of the reference gas value, at each calibration gas level *or* $|R - A_{avg}|$ ≤0.8 μg/scm.
RATA	Annual [4]	• Test deadline may be extended for "non-QA operating quarters," up to a maximum of 8 quarters from the quarter of the previous test. • 720 operating hour grace period available.	≤20.0% RA when C_{avg} ≥50% of the emissions limit *or* ≤10.0% RA when C_{avg} <50% of the emissions limit and the concentration equivalent of the applicable emission limit is used in the denominator of Equation 2–6 of PS2 (see Section 4.1.1.5.1 of this appendix).

[1] "Weekly" means once every 7 operating days.
[2] A "QA operating quarter" is a calendar quarter with at least 168 unit or stack operating hours.
[3] "Quarterly" means once every QA operating quarter.
[4] "Annual" means once every four QA operating quarters.

* * * * *

5.1.2.1 Calibration error tests of the Hg CEMS are required daily, except during unit outages. Use a NIST-traceable elemental Hg gas standard for these calibrations. Both a zero-level gas and either a mid-level or high-level gas are required for these calibrations.

* * * * *

5.1.2.3 Perform a single-level system integrity check weekly, *i.e.,* once every 7 operating days (see the third column in Table A–2 of this appendix).

* * * * *

5.2.1 Each sorbent trap monitoring system shall be continuously operated and maintained in accordance with Performance Specification (PS) 12B in appendix B to part 60 of this chapter. The QA/QC criteria for routine operation of the system are summarized in Table 12B–1 of PS 12B. Each pair of sorbent traps may be used to sample the stack gas for up to 15 operating days.

* * * * *

6. Data Reductions and Calculations

* * * * *

6.2.2.3 The applicable gross output-based Hg emission rate limit in Table 1 or 2 to this subpart must be met on a 30- (or 90-) boiler operating day rolling average basis, except as otherwise provided in § 63.10009(a)(2). Use Equation A–5 of this appendix to calculate the Hg emission rate for each averaging period.

$$\bar{E}_o = \frac{\sum_{h=1}^{n} E_{ho}}{n} \quad (Eq.\ A-5)$$

Where:

E_o = Hg emission rate for the averaging period (lb/GWh),

E_{ho} = Gross output-based hourly Hg emission rate for unit or stack sampling hour ''h'' in the averaging period, from Equation A–4 of this appendix (lb/GWh), and

n = Number of unit or stack operating hours in the averaging period in which valid data were obtained for all parameters.

(*Note:* Do *not* include non-operating hours with zero emission rates in the average).

* * * * *

7. Recordkeeping and Reporting

* * * * *

7.1.2.6 The EGUs that constitute an emissions averaging group.

* * * * *

■ 29. Appendix B to subpart UUUUU of part 63 is amended by:

■ a. Revising paragraph 2.1 and 2.3;

■ b. Adding paragraphs 2.3.1 and 2.3.2;

■ c. Revising paragraphs 3.1 and 3.2 and adding paragraph 3.3;

■ d. Adding introductory text to section 5. On-Going Quality Assurance Requirements;

■ e. Revising paragraphs 5.1, 5.2, and 5.3;

■ f. Adding paragraphs 5.4, 5.4.1, 5.4.2, 5.4.2.1, 5.4.2.2, 5.4.2.2.1, 5.4.2.2.2, 5.4.2.3, 5.4.2.3.1, 5.4.2.3.2, 5.4.2.3.3, and 5.4.3;

■ g. Revising section 8. introductory text;

■ h. Revising paragraphs 10.1.8, 10.1.8.1, 10.1.8.1.1, and 10.1.8.1.2, adding paragraph 10.1.8.1.2.1, and adding and reserving paragraph 10.1.8.1.2.2;

■ i. Revising paragraph 10.1.8.1.3;

■ j. Revising paragraphs 11.4 and 11.4.2 and removing and reserving paragraphs 11.4.2.1 through 11.4.2.13;

■ k. Revising paragraphs 11.4.3 and 11.4.3.1 through 11.4.3.13;

■ l. Revising paragraph 11.4.4 and adding and reserving paragraph 11.4.4.1;

■ m. Adding paragraph 11.4.5 and adding and reserving paragraph 11.4.5.1;

■ n. Adding paragraph 11.4.6 and adding and reserving paragraph 11.4.6.1;

■ o. Adding paragraphs 11.4.7, 11.4.7.1 through 11.4.7.13;

■ p. Revising paragraph 11.4.8 and

■ q. Revising paragraph 11.5.3.4.

■ The revisions and additions read as follows:

Appendix B to Subpart UUUUU of Part 63—HC_L and HF Monitoring Provisions

* * * * *

2. Monitoring of HC_L and/or HF Emissions

* * * * *

2.1 *Monitoring System Installation Requirements.* Install HCl and/or HF CEMS and any additional monitoring systems needed to convert pollutant concentrations to units of the applicable emissions limit in accordance with Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter for extractive Fourier Transform Infrared Spectroscopy (FTIR) continuous emissions monitoring systems and § 63.10010(a) or Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter for HCl CEMS and § 63.10010(a).

* * * * *

2.3 *FTIR Monitoring System Equipment, Supplies, Definitions, and General Operation.* The following provisions apply:

2.3.1 PS 15, Sections 2.0, 3.0, 4.0, 5.0, 6.0, and 10.0 of appendix B to part 60 of this chapter, or

2.3.2 PS 18, Sections 3.0, 6.0, and 11.0 of appendix B to part 60 of this chapter.

3. Initial Certification Procedures

* * * * *

3.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 15 using the procedures for gas auditing and comparison to a reference method (RM) as specified in sections 3.1.1 and 3.1.2 below.

* * * * *

3.2 If you choose to follow Performance Specification 18 (PS 18) of appendix B to part 60 of this chapter, then your HCl and/or HF CEMS must be certified according to PS 18, sections 7.0, 8.0, 11.0, 12.0, and 13.0.

3.3 Any additional stack gas flow rate, diluent gas, and moisture monitoring system(s) needed to express pollutant concentrations in units of the applicable emissions limit must be certified according to part 75 of this chapter.

* * * * *

5. On-Going Quality Assurance Requirements

On-going QA test requirements for HCl and HF CEMS must be implemented as follows:

5.1 If you choose to follow Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of PS 15 shall apply as set forth in sections 5.1.1 through 5.1.3 and 5.3.2 of this appendix.

* * * * *

5.2 If you choose to follow Performance Specification PS 18 of appendix B to part 60 of this chapter, then the quality assurance/quality control procedures of Procedure 6 of 40 CFR part 60, appendix F shall apply.

5.3 Stack gas flow rate, diluent gas, and moisture monitoring systems must meet the applicable on-going QA test requirements of part 75 of this chapter.

* * * * *

5.4 *Data Validation.*

5.4.1 *Out-of-Control Periods.* An HCl or HF CEMS that is used to provide data under this appendix is considered to be out-of-control, and data from the CEMS may not be reported as quality-assured, when any acceptance criteria for a required QA test is not met. The HCl or HF CEMS is also considered to be out-of-control when a required QA test is not performed on schedule or within an allotted grace period. To end an out-of-control period, the QA test that was either failed or not done on time must be performed and passed. Out-of-control periods are counted as hours of monitoring system downtime.

5.4.2 *Grace Periods.* For the purposes of this appendix, a ''grace period'' is defined as a specified number of unit or stack operating hours after the deadline for a required quality-assurance test of a continuous monitor has passed, in which the test may be performed and passed without loss of data.

5.4.2.1 For the flow rate, diluent gas, and moisture monitoring systems described in section 5.3 of this appendix, a 168 unit or stack operating hour grace period is available for quarterly linearity checks, and a 720 unit or stack operating hour grace period is available for RATAs, as provided, respectively, in sections 2.2.4 and 2.3.3 of appendix B to part 75 of this chapter.

5.4.2.2 For the purposes of this appendix, if the deadline for a required gas audit/data accuracy assessment or RATA of an HCl or HF CEMS cannot be met due to circumstances beyond the control of the owner or operator:

5.4.2.2.1 A 168 unit or stack operating hour grace period is available in which to perform the gas audit/data accuracy assessment; or

5.4.2.2.2 A 720 unit or stack operating hour grace period is available in which to perform the RATA.

5.4.2.3 If a required QA test is performed during a grace period, the deadline for the next test shall be determined as follows:

5.4.2.3.1 For a gas audit or RATA of the monitoring systems required under in section 5.3 of this appendix, determine the deadline for the next gas audit or RATA (as applicable) in accordance with section 2.2.4(b) or 2.3.3(d) of appendix B to part 75 of this chapter; treat a gas audit in the same manner as a linearity check.

5.4.2.3.2 For the gas audit/data accuracy assessment of an HCl or HF CEMS, the grace period test only satisfies the audit requirement for the calendar quarter in which the test was originally due. If the calendar quarter in which the grace period audit is performed is a QA operating quarter, an additional gas audit/data accuracy assessment is required for that quarter.

5.4.2.3.3 For the RATA of an HCl or HF CEMS, the next RATA is due within three QA operating quarters after the calendar quarter in which the grace period test is performed.

5.4.3 *Conditional Data Validation.* For recertification and diagnostic testing of the monitoring systems that are used to provide data under this appendix, and for the required QA tests when non-redundant backup monitoring systems or temporary like-kind replacement analyzers are brought into service, the conditional data validation provisions in § 75.20(b)(3)(ii) through (ix) of this chapter may be used to avoid or minimize data loss. The allotted window of time to complete calibration tests and RATAs shall be as specified in § 75.20(b)(3)(iv) of this chapter; the allotted window of time to complete a gas audit or data accuracy assessment shall be the same as for a linearity check (*i.e.,* 168 unit or stack operating hours).

* * * * *

8. QA/QC Program Requirements

The owner or operator shall develop and implement a quality assurance/quality control (QA/QC) program for the HCl and/or HF CEMS that are used to provide data under this subpart. At a minimum, the program shall include a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for the most important QA/QC activities. Electronic storage of the QA/QC plan is permissible, provided that the information can be made available in hard copy to auditors and inspectors. The QA/QC program requirements for the other monitoring systems described in paragraph 5.3 of this appendix are specified in section 1 of appendix B to part 75 of this chapter.

* * * * *

10. Recordkeeping Requirements

* * * * *

10.1.8 *Certification and Quality Assurance Test Records.* For the HCl and/or HF CEMS used to provide data under this subpart at each affected unit (or group of units monitored at a common stack), record the following information for all required certification, recertification, diagnostic, and quality-assurance tests:

10.1.8.1 *HCl and HF CEMS.*

10.1.8.1.1 For all required daily calibrations and checks (including calibration transfer standard tests) of the HCl or HF CEMS, record the test dates and times, reference values and their certification information, action levels for integrated path HCl CEMS, HCl or HF monitor responses, and calculated calibration error values;

10.1.8.1.2 For quarterly gas audits of HCl or HF CEMS certified under PS 15 of appendix B to part 60 of this chapter follow paragraph 10.1.8.1.2.1 of this appendix and for quarterly data accuracy assessments under PS 18 of appendix B to part 60 of this chapter follow paragraph 10.1.8.1.2.2 of this appendix.

10.1.8.1.2.1 Record the date and time of each spiked and unspiked sample, the audit gas reference values and uncertainties. Keep records of all calculations and data analyses required under sections 9.1 and 12.1 of P S 15 of appendix B to part 60 of this chapter, and the results of those calculations and analyses.

10.1.8.1.2.2 [Reserved]

10.1.8.1.3 For each RATA or RAA of a HCl or HF CEMS, record the date and time of each test run, the reference method(s) used, and the reference method and HCl or HF CEMS values. Keep records of the data analyses and calculations used to determine the relative accuracy.

* * * * *

11. Reporting Requirements

* * * * *

11.4 *Certification, Recertification, and Quality-Assurance Test Reporting Requirements.* Except for daily QA tests (*e.g.,* calibrations and flow monitor interference checks), which are included in each electronic quarterly emissions report, use the ECMPS Client Tool to submit the results of all required certification, recertification, quality-assurance, and diagnostic tests of the monitoring systems required under this appendix electronically, either prior to or concurrent with the relevant quarterly electronic emissions report.

* * * * *

11.4.2 For daily beam intensity checks for integrated path HCl CEMS as specified by PS 18 of appendix B to part 60 of this chapter, report:

11.4.2.1 through 11.4.2.13 [Reserved]

11.4.3 For each quarterly gas audit of an HCl or HF CEMS under Performance Specification 15, report:

11.4.3.1 Facility ID information;

11.4.3.2 Monitoring system ID number;

11.4.3.3 Type of test (*e.g.,* quarterly gas audit);

11.4.3.4 Reason for test;

11.4.3.5 Certified audit (spike) gas concentration value (ppm);

11.4.3.6 Measured value of audit (spike) gas, including date and time of injection;

11.4.3.7 Calculated dilution ratio for audit (spike) gas;

11.4.3.8 Date and time of each spiked flue gas sample;

11.4.3.9 Date and time of each unspiked flue gas sample;

11.4.3.10 The measured values for each spiked gas and unspiked flue gas sample (ppm);

11.4.3.11 The mean values of the spiked and unspiked sample concentrations and the expected value of the spiked concentration as specified in section 12.1 of PS 15 of appendix B to part 60 of this chapter (ppm);

11.4.3.12 Bias at the spike level as calculated using equation 3 in section 12.1 of PS 15 of appendix B to part 60 of this chapter; and

11.4.3.13 The correction factor (CF), calculated using equation 6 in section 12.1 of PS 15 of appendix B to part 60 of this chapter.

11.4.4 For each quarterly parameter verification check for an integrated path HCl CEMS under PS 18 of appendix B to part 60 of this chapter, report:

11.4.4.1 [Reserved]

11.4.5 For each quarterly gas audit under P S 18 of appendix B to part 60 of this chapter, report:

11.4.5.1 [Reserved]

11.4.6 For each quarterly dynamic spiking audit as allowed by P S 18 of appendix B to part 60 of this chapter, report:

11.4.6.1 [Reserved]

11.4.7 For each RATA or RAA of an HCl or HF CEMS, report:

11.4.7.1 Facility ID information;

11.4.7.2 Monitoring system ID number;

11.4.7.3 Type of test (*i.e.,* initial or annual RATA or RAA);

11.4.7.4 Reason for test;

11.4.7.5 The reference method used;

11.4.7.6 Starting and ending date and time for each test run;

11.4.7.7 Units of measure;

11.4.7.8 The measured reference method and CEMS values for each test run, on a consistent moisture basis, in appropriate units of measure;

11.4.7.9 Flags to indicate which test runs were used in the calculations;

11.4.7.10 Arithmetic mean of the CEMS values, of the reference method values, and of their differences;

11.4.7.11 Standard deviation, as specified in Equation 2–4 of PS 2 or PS 18, as applicable in appendix B to part 60 of this chapter;

11.4.7.12 Confidence coefficient, as specified in Equation 2–5 of PS 2 or PS 18, as applicable in appendix B to part 60 of this chapter; and

11.4.7.13 Relative accuracy calculated using Equation 2–6 of PS 2 or PS 18, as applicable in appendix B to part 60 of this chapter or, if applicable, according to the alternative procedure for low emitters described in paragraph 3.1.2.2 of this appendix. If applicable use a flag to indicate that the alternative RA specification for low emitters has been applied.

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11.4.8 *Reporting Requirements for Diluent Gas, Flow Rate, and Moisture Monitoring Systems.* For the certification, recertification, diagnostic, and QA tests of stack gas flow rate, moisture, and diluent gas monitoring systems that are certified and quality-assured according to part 75 of this chapter, report the information in section 10.1.8.2 of this appendix.

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11.5.3.4 The results of all daily calibrations (including calibration transfer standard tests and beam intensity checks of integrated path CEMS) of the HCl or HF monitor as described in paragraph 10.1.8.1.1 of this appendix; and

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[FR Doc. 2015–01699 Filed 2–13–15; 8:45 am]

BILLING CODE 6560–50–P