ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72 and 75

[EPA–HQ–OAR–2005–0132; FRL–8511–1]

RIN 2060–AN16

Revisions to the Continuous Emissions Monitoring Rule for the Acid Rain Program, NO_X Budget Trading Program, Clean Air Interstate Rule, and the Clean Air Mercury Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is finalizing rule revisions that modify existing requirements for sources affected by the federally administered emission trading programs including the NO_X Budget Trading Program, the Acid Rain Program, the Clean Air Interstate Rule, and the Clean Air Mercury Rule.

The revisions are prompted primarily by changes being implemented by EPA's Clean Air Markets Division in its data systems in order to utilize the latest modern technology for the submittal of data by affected sources. Other revisions address issues that have been raised during program implementation, fix specific inconsistencies in rule provisions, or update sources incorporated by reference. These revisions do not impose significant new requirements upon sources with regard to monitoring or quality assurance activities.

DATES: This final rule is effective on January 24, 2008, for good cause found as explained in this rule.

The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of January 24, 2008, for good cause found as explained in this rule.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2005–0132. All documents in the docket are listed in the *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. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Air and Radiation Docket, EPA/DC, EPA West Building, EPA Headquarters Library, 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 and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Matthew Boze, Clean Air Markets Division, U.S. Environmental Protection Agency, Clean Air Markets Division, MC 6204J, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, telephone (202) 343–9211, e-mail at *boze.matthew@epa.gov.* Electronic copies of this document can be accessed through the EPA Web site at: *http://www.epa.gov/airmarkets.*

SUPPLEMENTARY INFORMATION: *Regulated Entities.* Entities regulated by this action primarily are fossil fuel-fired boilers, turbines, and combined cycle units that serve generators that produce electricity, generate steam, or cogenerate electricity and steam. Some trading programs include process sources, such as process heaters or cement kilns. Although Part 75 primarily regulates the electric utility industry, certain State and Federal NO_X mass emission trading programs rely on subpart H of Part 75, and those programs may include boilers, turbines, combined cycle, and certain process units from other industries. Regulated categories and entities include:

Category	NAICS code	Examples of potentially regulated industries
Industry	221112 and others	Electric service providers Process sources with large boilers, turbines, combined cycle units, process heaters, or cement kilns where emissions exhaust through a stack.

This table is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities which EPA is now aware could potentially be regulated by this action. Other types of entities not listed in this table could also be regulated. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should carefully examine the applicability provisions in §§ 72.6, 72.7, and 72.8 of title 40 of the Code of Federal Regulations and in 40 CFR Parts 96 and 97. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

Judicial Review. Under CAA section 307(b), judicial review of this final action is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit on or before March 24, 2008. Under CAA section 307(d)(7)(B), only those objections to the final rule that were raised with specificity during the period for public comment may be raised during judicial review. Moreover, under CAA section 307(b)(2), the requirements established by today's final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements. Section 307(d)(7)(B) also provides a mechanism for the EPA to convene a proceeding for reconsideration if the petitioner demonstrates that it was impracticable to raise an objection during the public comment period or if the grounds for such objection arose after the comment period (but within the time for judicial review) and if the objection is of central relevance to the rule. Any person seeking to make such a demonstration to EPA should submit a Petition for Reconsideration, clearly labeled as such, to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., Washington, DC 20460, with a copy to the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel, Mail Code 2344A, U.S. EPA, 1200 Pennsylvania Ave., NW., Washington, DC 20460.

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I. Detailed Discussion of Rule Revisions

EPA is in the process of re-engineering the data systems associated with the collection and processing of emissions, monitoring plan, quality assurance, and certification data. The re-engineering project includes the creation of a client tool, provided by EPA that sources will use to evaluate and submit their Part 75 monitoring data. This process change will enable sources to assess the quality of their data prior to submitting the data using EPA established checking criteria. The process will also allow sources to report their data directly to a database. Having the data in a true database will allow the Agency to implement and assess the program more efficiently and will streamline access to the data. Also, this database structure will enable EPA to implement process changes that will reduce the redundant reporting of certain types of data. The re-engineered systems will be supported by a new extensible markup language (XML) data format that will replace the record type/column format currently used by EPA to collect electronic data. EPA intends to transition existing sources to the new XML electronic data report (XML–EDR) format during the 2008 reporting year. For sources reporting in 2008 for the first time, the new XML–EDR format should be used. All sources will be required to use the new process beginning in 2009.

Therefore, EPA finds good cause to determine that the final rule is effective on January 24, 2008. EPA normally issues final regulations with at least a 30-day effective date after **Federal Register** publication. However, this provision of the rule which pertains to the re-engineering of the Clean Air Markets Division's data systems and to implementation of the Clean Air Mercury Regulation (CAMR), must be effective by January 1, 2008. Today's rule allows sources the option of reporting emissions data in the new XML data reporting format in 2008, one year before the use of XML becomes mandatory. The final rule provides the necessary record keeping and reporting requirements to support the XML format. Second, sources subject to CAMR are required to install and certify continuous mercury (Hg) monitoring systems by January 1, 2009. To meet this deadline, companies with multiple CAMR-affected units will begin monitor certification testing in the first quarter of 2008. As described in Sections I.C.3 and I.O.3., today's rule adds two recently-published Hg test methods, *i.e.*, Methods 30A and 30B, to Part 75 as alternatives to the Ontario Hydro Method. For many sources, 30A and 30B will be the test methods of choice. Third, as discussed in Section I.A., today's rule defers until January 1, 2010 the requirement for the calibration standards used to certify Hg continuous emission monitoring systems (CEMS) under CAMR to be traceable to the National Institute of Standards and Technology (NIST). Fourth, for CAMR units that seek to qualify as low mass emitting units under § 75.81, Hg emission testing is required in 2008. As discussed in Section G.2., today's rule adds considerable flexibility to the way in which this testing is conducted, particularly for common stack configurations and groups of identical units. The use of Methods 30A and 30B for this testing is also desirable. Absent this determination of good cause, sources would not be able to begin scheduled monitoring certification activities until the necessary provisions of this rule became effective. A thirty day delay would significantly decrease the overall amount of time available for industry to comply with the certification deadline of January 1, 2009. Such a delay could result in sources not being able to meet the certification deadline, since industry would lose some of its ability to spread utilization of various certification resources (*i.e.*, test teams, equipment, and vendor support) over the entire course of 2008.

For these reasons, EPA believes it has good cause to expedite the effective date of this final rule.

A. Rule Definitions

Background

EPA proposed to add several new definitions to Part 72, including definitions for: ''Long-term cold storage'' (to mean the complete shutdown of a unit intended to last for at least two calendar years); ''EPA Protocol Gas Verification Program'' (to support the proposed calibration gas audit program); ''Air Emission Testing Body (AETB)'' and ''Qualified Individual'' (to support the proposed stack tester accreditation program).

EPA also proposed to modify the definitions of ''Capacity factor'', ''EPA protocol gas,'' and ''Excepted monitoring system'', and to remove the definition of ''Calibration gas'' and related definitions describing the various types of gas standards that are classified as calibration gas.

Summary of Rule Changes

All of the proposed new and modified definitions have been finalized without substantive changes. However, one commenter cautioned that removing the definitions of the calibration gas standards from Part 72 might have consequences that could necessitate further rule revisions. In view of this, the Agency reconsidered these proposed changes and the final rule retains all but one of the definitions. The definition of ''Research gas material'' was found to be identical to the definition of ''Research gas mixture'' and has been removed from the rule.

Further, for consistency with Method 30A, the new instrumental reference method for mercury (Hg) (which, as noted in sections I.C.3 and I.O.3 of this preamble has been added to the list of acceptable Hg reference methods in § 75.22), and in light of other changes in today's rule related to the certification of Hg monitoring systems, EPA is adding definitions of ''NIST traceable elemental Hg standards'' and ''NIST traceable source of oxidized Hg'' to § 72.2. These definitions pertain to Hg calibration gas standards and are deemed necessary for implementation of the continuous monitoring requirements of the Clean Air Mercury Regulation (CAMR).

Affected units under CAMR are required to install and certify Part 75-compliant Hg monitoring systems by January 1, 2009. To meet this requirement, the vast majority of the

certification testing will be performed in 2008. When CAMR was first proposed, only one reference test method (the Ontario Hydro (OH) Method) was prescribed for the relative accuracy test audits (RATAs) of the required Hg monitoring systems. However, the OH method is wet chemistry-based, and is both difficult and expensive to perform. Also, the laboratory analysis required to obtain the test results can take a week or more, making the OH method incompatible with the Hg emissions trading program described in the CAMR model rule.

In a cap and trade program, the RATA results must be known while the test team is still on-site, so that any necessary corrective actions can be taken and retesting performed without delay. With the OH method, if the results of the lab analysis indicate a RATA failure, a retest must be rescheduled and the Hg monitoring system is considered out-of-control until a subsequent RATA is passed. This can result in an extended missing data period and loss of Hg allowances.

Thus, it became apparent during the CAMR rulemaking that an alternative to the OH method was needed. An instrumental Hg reference method was put forth as the logical choice, because it would provide real-time Hg concentration data, allowing the RATA results to be known on the day of the test. When CAMR was published on May 18, 2005, EPA stated its intention to ''propose and promulgate'' an instrumental Hg reference method (see 70 FR 28636). In support of the final CAMR rule, Hg monitoring provisions were added to Part 75. Among these was an amendment to § 75.22, allowing the use of either the OH method or an ''instrumental reference method * * * subject to the approval of the Administrator'' for the certification testing of Hg continuous monitoring systems. Method 30A was published on September 7, 2007 in a direct-final rulemaking, and became effective on November 6, 2007 (*see* 72 FR 51494). Method 30A represents the fulfillment of the Agency's commitment to publish an instrumental reference method for Hg.

One of the most important Part 75 requirements for the certification of Hg continuous emission monitoring systems (CEMS) is that the concentrations of the elemental and oxidized Hg calibration gas standards used for the 7-day calibration error tests, linearity checks, and system integrity checks of the CEMS must be traceable to the National Institute of Standards and Technology (NIST) (*see* Part 75, Appendix A, Section 5.1.9). This NIST traceability requirement for Hg standards is modeled after the NIST traceability requirements in Section 5 of Appendix A for SO_2, NO_X, and diluent gas (CO_2 and O_2) calibration gas standards.

For the SO_2, NO_X, CO_2, and O_2 compressed gas standards used in Part 75 applications, ''NIST traceability'' means that the calibration gases have been prepared according to the EPA-approved protocol cited in Section 5.1.4 of Appendix A. Further, § 75.22(c)(1) requires NIST-traceable gas standards to be used to calibrate the instrumental reference methods used for relative accuracy testing of SO_2, NO_X, CO_2, and O_2 CEMS (*i.e.*, Methods 6C, 7E and 3A).

Prior to today's rulemaking, no NIST traceability protocols for Hg calibration standards were referenced in Part 75. The new definitions of ''NIST traceable elemental Hg standards'' and ''NIST traceable source of oxidized Hg'' address this deficiency and cite the EPA protocols that must be followed to ensure that the elemental and oxidized Hg standards are traceable to NIST. However, these protocols, which are referenced in Section 16.0 of Method 30A, are not yet fully developed, and are not expected to be ready for use until the latter part of 2008. A cooperative field demonstration program that will include representatives from EPA, NIST, industry, equipment vendors, and other key personnel is planned for the coming months, to gather the data necessary to refine and finalize the traceability protocols. Once these traceability protocols are finalized, they will be posted on the Agency's Technology Transfer Network Web site (*http://www.epa.gov/ttn/emc/*) and on the Agency's Clean Air Markets Division Web site (*http://www.epa.gov/airmarkets/*).

In view of this, EPA is temporarily deferring (until January 1, 2010) the requirement for elemental and oxidized Hg standards to be NIST traceable. The deferral affects both initial certifications of the CEMS and routine quality-assurance tests of the CEMS performed prior to January 1, 2010. Note that only the NIST traceability requirement for the Hg calibration standards is being waived, not the requirement to perform the calibration error tests, linearity checks, and system integrity checks of the Hg monitoring systems by January 1, 2009.

Beginning on January 1, 2010, all daily calibration error tests, linearity checks, and system integrity checks of Hg CEMS must be performed using NIST traceable elemental and oxidized Hg calibration standards, as defined in § 72.2. Section 5.1.9 of Appendix A to Part 75 has been revised to reflect this. In view of this, EPA strongly recommends that in 2009, all CAMR-affected sources should take the necessary steps to ensure that the NIST traceability requirement is met. In most cases, this will involve the certification of elemental and oxidized Hg generators, according to the traceability protocols. If a source elects to perform daily calibrations and/or linearity checks using compressed gas cylinders instead of an elemental Hg generator, the owner or operator will have to obtain cylinder gases that conform to the EPA traceability protocol for gaseous calibration standards.

Finally, note that EPA is conditionally allowing Method 30A to be used for Part 75 Hg emission testing and RATA applications prior to finalization of the traceability protocols in section 16.0 of the method. The condition is that interim traceability protocols are developed and posted on the Agency's Technology Transfer Network Web site (*http://www.epa.gov/ttn/emc/*), as ''broadly applicable alternative test method approvals'' that will expire when the final protocols are issued. EPA's authority to approve such test method alternatives is described in 72 FR 4257, January 30, 2007.

EPA believes that a phased-in approach to NIST traceability is appropriate and necessary, in light of the additional time needed to finalize the traceability protocols and the time required for the affected sources and equipment vendors to set up the necessary infrastructure to implement the protocols. The Agency also believes that this approach will not compromise the quality of the data for the emissions trading program under CAMR, since in 2010, the first year in which Hg emissions count against allowances held, NIST traceability of the Hg calibration standards is mandatory.

B. General Monitoring Provisions

1. Update of Incorporation by Reference (§ 75.6)

Background

Section 75.6 identifies a number of methods and other standards that are incorporated by reference into Part 75. This section includes standards published by the American Society for Testing and Materials (ASTM), the American Society of Mechanical Engineers (ASME), the American National Standards Institute (ANSI), the Gas Processors Association (GPA), and the American Petroleum Institute (API). EPA proposed changes to § 75.6 that would reflect the need to incorporate

recent updates for many of the referenced standards. The proposed revisions would recognize or adhere to these newer standards by updating references for the standards listed in §§ 75.6(a) through 75.6(f). Additionally, new §§ 75.6(a)(45) through 75.6(a)(48) and 75.6(f)(4) would incorporate by reference additional ASTM and API standards that are relevant to Part 75 implementation.

Summary of Rule Changes

The updates and additions to § 75.6 have been finalized as proposed. One commenter requested that an additional ASTM method for analyzing the sulfur content of low-sulfur fuel oil, i.e., ASTM D5453–06, ''Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence'', be added to the list of acceptable methods in § 75.6. This method has been incorporated by reference as § 75.6(a)(49) and has been added to section 2.2.5 of Appendix D.

2. Default Emission Rates for Low Mass Emissions (LME) Units

Background

EPA proposed to allow LME units to use site-specific default SO_2 emission rates for fuel oil combustion, in lieu of using the ''generic'' default SO_2 emission rates specified in Table LM–1 of § 75.19. To use this option, a federally enforceable permit condition would have to be in place for the unit, limiting the sulfur content of the oil. This revision, if made, would allow more representative, yet still conservatively high, SO_2 emissions data to be reported from oil-burning LME units. As proposed, the site-specific default SO_2 emission rate would be calculated using an equation from EPA publication AP–42. The sulfur content used in the calculations would be the maximum weight percent sulfur allowed by the federally-enforceable permit. Sources choosing to implement this option would be required to perform periodic oil sampling using one of the four methodologies described in Section 2.2 of Appendix D to Part 75, and would be required to keep records documenting the sulfur content of the fuel.

The Agency also proposed to revise § 75.19(c)(1)(iv)(G) to clarify that fuel-and-unit-specific default NO_X emission rates for LME units may be determined using data from a Continuous Emissions Monitoring System (CEMS) that has been quality-assured according to either Appendix B of Part 75 or Appendix F of Part 60, or comparably quality-assured under a State CEMS program. Lastly, the Agency proposed technical revisions to the Equations LM–5 and LM–6 changing the units of rate to units of measure to make the equations correct as units of rate cannot technically be summed.

Summary of Rule Changes

Commenters were generally supportive of the proposed revisions to § 75.19, and they have been finalized with only one substantive change. EPA has incorporated one commenter's suggestion not to restrict the allowable fuel oil sampling options to those described in Appendix D. The final rule allows the use of other consensus standard fuel sampling methods (e.g., ASTM, API, etc.) specified in applicable State or Federal regulations or in the unit's operating permit, to determine the sulfur content of the oil.

Another commenter requested that EPA go beyond its proposal for SO_2 and consider providing a similar, more reasonable site-specific alternative to reporting the generic NO_X emission rates in Table LM–2. Specifically, the commenter suggested that for units with very low annual capacity factors, the Agency should waive the testing requirements of §§ 75.19(c)(1)(iv) and allow emission test data that was generated more than 5 years ago (e.g., from a Part 60 performance test) to be used to determine fuel-specific default NO_X emission rates. The commenter asserted that the cost of additional testing could impose a financial burden on smaller affected sources. After careful consideration, EPA decided against allowing infrequently-operated units to use emission test data older than 5 years for Part 75 reporting. However, § 75.19(c)(1)(iv)(I) has been amended to provide reduced emission testing requirements for very low capacity factor LME units. The final rule allows single-load testing, between 75 and 100 percent of maximum load, to be performed (both for the initial Appendix E testing and for retests) if, for the 3 years prior to the year of the test, the unit's average capacity factor was 2.5 percent or less and did not exceed 4.0 percent in any of those three years. Alternatively, for combustion turbines, the emission test may be done at the maximum attainable load corresponding to the season of the year in which the test is performed. For a group of identical units, the single-load testing option may be used for any unit(s) in the group that meet the very low capacity factor requirements. For a more detailed discussion of this issue, refer to section 2.3.2 of the Response to Comments (RTC) document.

3. Default Moisture Value for Natural Gas

Background

EPA proposed to allow gas-fired boilers equipped with CEMS to use default moisture values in lieu of continuously monitoring the stack gas moisture content. Two conservative default values were proposed: 14.0% H_2O under § 75.11(b), and 18.0% H2O under § 75.12(b). The Agency also proposed that the higher default value would apply only when Equation 19–3, 19–4, or 19–8 (from Method 19 in appendix A–7 to part 60 of this chapter) is used to determine the NO_X emission rate. The proposed default values represent the 10th and 90th percentile values from two sets of supplemental moisture data provided to the Agency, which is consistent with the approach that the Agency has used in responding to past petitions under § 75.66 for site-specific default moisture values.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and they have been finalized.

4. Expanded Use of Equation F–23

Background

EPA proposed to revise § 75.11(e)(1) to remove the current restrictions on the use of Equation F–23 to determine the SO_2 mass emission rate, by allowing Equation F–23 to be used whether or not the unit has an SO_2 monitor and to expand its use to fuels other than natural gas. The proposal would allow Equation F–23 to be used for any gaseous fuel that qualifies for a default SO_2 emission rate under Section 2.3.6(b) of Appendix D. Further, Equation F–23 could be used for the combustion of liquid and solid fuels that meet the definition of ''very low sulfur fuel'' in § 72.2, if a petition for a fuel-specific default SO_2 emission rate is submitted to the Administrator under § 75.66 and the Administrator approves the petition. Under the proposed rule, petitions would also be accepted for the combustion of mixtures of these fuels and for the co-firing of these fuels with gaseous fuel.

Summary of Rule Changes

Commenters were supportive of the expanded use of Equation F–23 and the revisions to § 75.11(e) and corresponding changes to section 7 of Appendix F have been finalized as proposed.

5. Calculation of NO_X Emission Rate—LME Units

Background

EPA proposed to re-title § 75.19(c)(4)(ii) as ''NO_X mass emissions and NO_X emission rate'' and to add a new subparagraph (D) to § 75.19 (c)(4)(ii), providing instructions for determining quarterly and cumulative NO_X emission rates for a LME unit. The NO_X emission rate for each hour (lb/mmBtu) would simply be the appropriate generic or unit-specific default NO_X emission rate defined in the monitoring plan for the type of fuel being combusted and (if applicable) the NO_X emission control status. Then, the Agency proposed that the quarterly NO_X emission rate would be determined by averaging all of the hourly NO_X emission rates and the cumulative (year-to-date) NO_X emission rate would be the arithmetic average of the quarterly values.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and the revisions to § 75.19(c)(4)(ii) have been finalized as proposed.

6. LME Units—Scope of Applicability

Background

EPA proposed to revise § 75.19(a)(1) to clarify that the low mass emissions (LME) methodology is a stand-alone alternative to a CEMS and/or the ''excepted'' monitoring methodologies in Appendices D, E, and G. In other words, if a unit qualifies for LME status, the owner or operator is required either to use the LME methodology for all parameters or not to use the method at all. No mixing-and-matching of other monitoring methodologies with LME is permitted. Parallel revisions to §§ 75.11(d)(3), 75.12(e)(3), and 75.13(d)(3), consistent with the changes to § 75.19(a)(1), were also proposed to clarify the Agency's intent.

Summary of Rule Changes

No adverse comments were received on the proposed changes and they have been finalized.

7. Use of Maximum Controlled NO_X Emission Rate When Using Bypass Stacks

Background

Revisions to § 75.17(d)(2) were proposed that would allow a maximum controlled NO_X emission rate (MCR) to be reported instead of the maximum potential NO_X emission rate (MER) whenever an unmonitored bypass stack is used, provided that the add-on controls are not bypassed and are documented to be operating properly. For example, for a coal-fired unit equipped with FGD and SCR add-on emission controls, if the SCR is documented to be working during an FGD malfunction and the effluent gases are routed through an unmonitored bypass stack after passing through the SCR, then the MCR, rather than the MER, would be the more appropriate NO_X emission rate to report for the bypass hour(s). Documentation of proper add-on control operation for such hours of operation would be required as described in § 75.34(d). The MCR would be calculated in a manner similar to the calculation of the MER, except that the maximum expected NO_X concentration (MEC) would be used instead of the maximum potential NO_X concentration (MPC).

Summary of Rule Changes

Commenters were generally supportive of the proposed rule changes and they have been finalized. One commenter recommended that parallel language be added to § 75.72(c)(3), to cover non-Acid Rain Program units that are subject to the NO_X mass emissions monitoring provisions of Subpart H. EPA agrees with this comment and has added the necessary language to § 75.72(c)(3).

C. Certification Requirements

1. Alternative Monitoring System Certification

Background

EPA proposed to delete §§ 75.20(f)(1) and (2) from the rule, thereby removing the requirement for the Administrator to publish each request for certification of an alternative monitoring system in the **Federal Register**, with an associated 60-day public comment period. This rule provision is considered unnecessary, in view of the Agency's authority under Subpart E to approve alternative monitoring systems and the rigorous requirements in §§ 75.40 through 75.48 that alternative monitoring systems must meet in order to be certified.

Summary of Rule Changes

Commenters were supportive of the proposed amendments to § 75.20(f), and they have been finalized.

2. Part 60 Reference Test Methods

Background

On May 15, 2006, EPA promulgated final revisions to EPA reference test methods 6C, 7E, and 3A, which are found in Appendix A of 40 CFR Part 60. (See 71 FR 28082, May 15, 2006). These test methods are prescribed for Part 75 emission testing and RATAs. Three new testing options that were added to the methods were deemed unacceptable for use under Part 75. These include:

(1) Section 7.1 of revised EPA Method 7E, allowing for custom calibration gas concentrations to be produced by diluting EPA protocol gases, in accordance with Method 205 in Appendix M of 40 CFR Part 51.

(2) Section 8.4 of revised EPA Method 7E, allowing the use of a multi-hole ''rake'' probe to satisfy the multipoint traverse requirement of the method.

(3) Section 8.6 of revised EPA Method 7E, allowing for the use of ''dynamic spiking'' as an alternative to the interference and system bias checks of the method.

Although revised Method 7E states that for use under Part 75 the three options above require approval by the Administrator, EPA proposed to add similar language to § 75.22(a)(5) to reinforce its position regarding these testing alternatives.

Summary of Rule Changes

No adverse comments were received on the proposed amendments to § 75.22(a)(5) and they have been finalized. However, one commenter brought to EPA's attention another revision to the Part 60 reference methods that impacts Part 75. EPA Method 20 was also revised on May 15, 2006. Method 20 has been the NO_X emission test method prescribed for combustion turbines (CTs) in section 2.1.2.2 of Appendix E. Method 20 has also been used to determine fuel-specific NO_X emission rates for combustion turbines that qualify as low mass emissions (LME) units under § 75.19.

The original Method 20 required testing at 8 sampling points per run, with typical run times averaging about 15 to 20 minutes. However, the revised Method 20 no longer specifies the minimum number of test points per run, but rather requires sampling point selection to be done according to Method 7E. Revised Method 7E requires 12 traverse points for an emission test run (which would suffice for Appendix E testing), but the method also allows the results of stratification testing to be used to justify using three or, in some cases, one sample point instead. This raises questions about the required length of an Appendix E test run. For instance, if testing were required at only one point, each Appendix E test run would be reduced from 15–20 minutes to as little as 2 minutes (depending on the system response time). The commenter stated that such short sampling runs seem inadequate to

develop a substantial correlation curve for emission reporting. The commenter recommended that EPA modify Appendix E or Method 20 and either set a minimum run time of 20 minutes (providing an hour of data at each load) or specify a minimum number of sampling points for an Appendix E test of a CT.

EPA has incorporated the commenter's recommendations into Part 75. First, § 75.22(a)(5) has been amended to prohibit the use of Method 7E to determine the required number of sample points for the emission testing of a combustion turbine. Section 75.22(a)(5)(ii) requires the sample points to be determined according to section 2.1.2.2 of Appendix E, instead. Second, for the emission test of a CT, section 2.1.2.2 of Appendix E has been revised to require a minimum of 12 test points per run, located according to EPA Method 1. Third, amendments have been made to § 75.22(a)(6), § 75.19(c)(1)(iv)(A), section 6.5.10 of Appendix A, and sections 2.1.2.2 and 2.1.2.3 of Appendix E, to remove all references to EPA Method 20 from Part 75. Fourth, for the testing of an Appendix E boiler, the text of section 2.1.2.1 of Appendix E has been revised to require 12 traverse points per run, making it consistent with revised section 2.1.2.2 (note that this is not a new requirement—section 2.1.2.1 has always required 12 test points, located according to section 8.3.1 of Method 3, and that section refers back to Method 1). Finally, in section 2.1.2.3 of Appendix E, the references to the measurement system response time in section 5.5 of Method 20 (which section no longer exists) have been replaced with references to the response time provisions in sections 8.2.5 and 8.2.6 of Method 7E. Appendix E tests performed on CTs prior to the effective date of these amendments are grandfathered from the revised test point location requirements.

3. Mercury Reference Methods

Background

EPA proposed to add an alternative relative deviation (RD) specification for the results of mercury (Hg) emission data collected with paired Ontario Hydro (OH) reference method sampling trains. The principal RD specification in § 75.22(a)(7) is 10 percent. However, this acceptance criterion may be too stringent for sources with low Hg emissions. Therefore, for average Hg concentrations of 1.0 μg/m^3 or less, EPA proposed an alternative RD specification of 20 percent. This is consistent with the acceptance criteria for data from paired OH trains, as specified in Performance Specification 12A in Appendix B of 40 CFR Part 60.

EPA also proposed amendments to §§ 75.22(a)(7), 75.59(a)(7), 75.81(c)(1), and to sections 6.5.10 and 7.6.1 of Appendix A, allowing EPA Method 29 (back-half impinger catch, only) to be used as an alternative to the OH method, both for RATA testing and for periodic emission testing of units with low Hg mass emissions (≤29 lb/yr). Two caveats on the use of Method 29 were proposed. First, sources electing to use Method 29 (which is similar to the OH method, but somewhat simpler and more familiar to stack testers) would be required to use paired sampling trains (i.e., two trains sampling the source effluent simultaneously), and the RD specifications in § 75.22(a)(7) would have to be met for each run. Second, certain analytical and quality assurance (QA) procedures in the OH method (ASTM D6784–02) would have to be followed instead of the corresponding procedures in Method 29 (because the analytical and quality assurance/quality control (QA/QC) requirements of the OH method are more detailed and rigorous than those in Method 29), and testers could opt to follow several of the sample recovery and preparation procedures in the OH method instead of the Method 29 procedures.

Finally, the Agency solicited comment on the use of sorbent traps for reference method testing. Members of the regulated community had expressed an interest in using portable sorbent trap monitoring systems for Hg reference method testing, as an alternative to the OH method. EPA proposed to accommodate a possible future sorbent-based reference method by adding language to § 75.22(a)(7) that would allow an ''other suitable'' reference method approved by the Administrator to be used for Hg emission testing and RATAs.

Summary of Rule Changes

Commenters were generally supportive of the proposed amendments that would add Method 29 as an alternative Hg reference method, and those provisions have been finalized without substantive change. One commenter objected to the requirement to use paired sampling trains for OH and Method 29 tests, asserting that this adds to the cost of testing and may result in significant numbers of test runs being discarded. However, EPA does not agree with the commenter. The Agency believes rather that paired sampling trains provide added assurance of data quality when these test methods are used. The decision to require paired trains for the OH method was made during the rulemaking that led to publication of the Clean Air Mercury Regulation (CAMR) (*see* 70 FR 28636–28639, May 18, 2005).

Two commenters supported the proposed 20 percent alternative RD specification for low emitters, and that provision has been finalized. However, one of the commenters noted that even a 20 percent RD specification may be too stringent for extremely low Hg concentrations. EPA agrees that when Hg concentrations are exceptionally low (0.1 μg/m^3 or less), the 20 percent RD specification may be difficult to meet. Therefore, the final rule adds a third tier to the RD specifications in § 75.22. The paired train agreement is also considered to be acceptable if the absolute difference between the two measured Hg concentrations does not exceed 0.03 μg/m^3.

Several commenters strongly supported the proposal to allow the use of a sorbent-based reference method for Hg emission testing and for the RATAs of Hg monitoring systems. Since publication of the proposed rule, a great deal of progress has been made in this area. First, EPA conducted a Method 301 analysis of available data comparing sorbent trap sampling to the OH method. The results of this analysis showed that a sorbent-based sampling method can be a viable alternative reference method. Second, EPA drafted ''Method 30B'', a reference method that uses iodated carbon traps to measure vapor phase Hg emissions. Finally, as part of a direct final rulemaking, Method 30B was published on September 7, 2007 (*see* 72 FR 51494–51531), along with Method 30A, an instrumental Hg reference method. Today's final rule allows both Methods 30A and 30B to be used.

D. Missing Data Substitution

1. Block Versus Step-Wise Approach

Background

Historically, EPA's policy has required sources to use a ''block'' approach for CEMS missing data substitution. The percent monitor data availability (PMA) at the end of the missing data period has been used to determine which mathematical algorithm applies, and the substitute data value or values prescribed by that one algorithm have been reported for each hour of the missing data period.

However, EPA has recently reconsidered and revised its missing substitution data policy, to allow sources to apply the missing data algorithms in a stepwise manner instead of using the block approach. Under the

stepwise methodology, the various missing data algorithms are applied sequentially. That is, the least conservative algorithm is applied to the missing data hours until the PMA drops below 95%. Then, the next algorithm is applied until the PMA has dropped below 90%, and so on.

Since Part 75 is not clear about which of the two methods should be used for missing data substitution, EPA proposed to amend §§ 75.33 and 75.32(b), to clarify that the stepwise, hour-by-hour method is the preferred one, and that use of that method would be required for all CEMS data recorded on and after January 1, 2009, and for any CEMS data recorded in XML-format during the transition year of 2008.

Summary of Rule Changes

Commenters unanimously supported the proposal to adopt stepwise missing data substitution and the proposed amendments to §§ 75.32 and 75.33 have been finalized.

2. Substitute Data Values for Controlled Units

Background

For units with add-on emission controls, when the PMA for SO_2 or NO_X is below 90.0 percent, § 75.34(a)(3) has historically allowed the designated representative (DR) to petition the Administrator under § 75.66 for permission to report the maximum controlled concentration or emission rate recorded in a specified lookback period instead of reporting the maximum value recorded in that lookback period, for each missing data hour in which the add-on controls are documented to be operating properly. After more than ten years of implementing the Acid Rain Program, EPA no longer believes that such special petitions are necessary, because sources with add-on controls are required to implement a quality assurance/quality control (QA/QC) program that includes the recording of parametric data to document the hourly operating status of the emission controls. This parametric information must be made available to inspectors and auditors upon request. Therefore, any claim that the emission controls were operating properly during a particular missing data period can be easily verified through the audit process.

In view of this, the Agency proposed to remove from § 75.34(a)(3) and § 75.66(f) the requirement to petition the Administrator to use the maximum controlled SO_2 or NO_X concentration (or maximum controlled NO_X emission rate) from the applicable lookback period. The proposed revisions would simply allow the maximum controlled values to be reported whenever parametric data are available to document that the emission controls are operating properly. The proposed rule would further clarify that this reporting option applies only to the third missing data tier, when the PMA is greater than or equal to 80.0 percent, but less than 90.0 percent.

EPA also proposed to add a new paragraph (a)(5) to § 75.34, which would allow units with add-on emission controls to report alternative substitute data values for missing data periods in the fourth missing data tier, when the PMA is below 80.0 percent. Proposed § 75.34(a)(5) would allow the owner or operator to replace the maximum potential SO_2 or NO_X concentration (MPC) or the maximum potential NO_X emission rate (MER) with a less conservative substitute data value, for missing data hours where parametric data, (as described in §§ 75.34(d) and 75.58(b)) are available to verify proper operation of the add-on controls. Specifically, for SO_2 and NO_X concentration, the replacement value for the MPC would be the greater of: (a) The maximum expected concentration (MEC); or (b) 1.25 times the maximum controlled value in the standard missing data lookback period. For NO_X emission rate, the replacement value for the MER would be the greater of: (a) The maximum controlled NO_X emission rate (MCR); or (b) 1.25 times the maximum controlled value in the standard missing data lookback period. The NO_X MCR would be calculated in the same manner as the NO_X MER, except that the MEC, rather than the MPC, would be used in the calculation. The proposed alternative data substitution methodology in § 75.34(a)(5) would ensure that the substitute data values for the fourth missing data tier are always higher than the corresponding substitute data values for the third tier.

Finally, EPA proposed to revise § 75.38(c) to extend the alternative missing data options for the third and fourth tiers to mercury (Hg) concentration, and § 75.58(b)(3) would be revised to be consistent with the proposed revisions to §§ 75.34(a)(3), 75.34(a)(5), and 75.38(c).

Summary of Rule Changes

Comments on the proposed alternative missing data substitution values for controlled units were generally supportive and these provisions have been finalized. Two commenters requested that parallel language be added to § 75.72(c)(3), to extend the use of the new missing data provisions to ozone season-only reporters. Another commenter asked EPA to clarify that the MCR may be implemented on a fuel-specific basis. EPA has incorporated both of these suggestions in the final rule. Two other commenters suggested that, for common stack configurations, EPA should allow the substitute data values to be apportioned or prorated in some way instead of requiring maximum potential values to be reported, in cases where the emission controls installed on some of the units sharing the stack are documented to be operating properly, but such documentation cannot be provided for the controls on the other units. The Agency believes that this approach would unnecessarily complicate the missing data substitution process and would provide no assurance that emissions are not being underestimated. Therefore, this suggestion was not incorporated in the final rule.

3. Substitute Data Values for Hg

Background

EPA proposed to revise the Hg missing data procedures. First, for Hg CEMS, the text of § 75.38(a) would be amended to clarify that the PMA ''trigger conditions'' for Hg monitoring systems are different from the trigger conditions for all other parameters. For all parameters except Hg, the trigger points that define the boundaries of the four missing data tiers are 95 percent, 90 percent, and 80 percent PMA. However, for Hg the corresponding trigger points are 90 percent, 80 percent and 70 percent, respectively.

Second, EPA proposed to completely revise the missing data provisions in § 75.39 for sorbent trap monitoring systems, to make them the same as for Hg CEMS, so that. the initial missing data procedures of § 75.31(b) and the standard Hg missing data provisions of § 75.38 would be followed for sorbent trap systems. EPA believes that this proposed missing data approach greatly simplifies the missing data substitution process for Hg monitoring systems. The hourly Hg concentration data stream from a sorbent trap system will look essentially the same as the data stream from a CEMS, except that the Hg concentration will ''flat-line'' (i.e., will not change) during each data collection period. Therefore, under the proposal, when the owner or operator elects to use a primary Hg CEMS and a backup sorbent trap system (or vice-versa), the appropriate substitute data values would be derived from a lookback through the previous 720 hours of quality-assured data, irrespective of

whether they were from the primary monitoring system or from the backup system.

Summary of Rule Changes

Commenters were supportive of the proposed changes to the sorbent trap missing data procedures in § 75.39, and these provisions have been finalized.

4. Correction of Cross-References

Background

For sources that report emissions data on an ozone season-only basis, EPA proposed to revise § 75.74(c)(3)(xi) and (c)(3)(xii) by replacing references to specific missing data sections with more general references to the entire block of CEMS missing data sections, i.e., §§ 75.31 through 75.37.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and they have been finalized, as proposed.

E. Recordkeeping and Reporting

Background

To accommodate its new, re-engineered XML reporting format, which will replace the current electronic data reporting (EDR) format in 2009, EPA proposed to revise the monitoring plan recordkeeping requirements in § 75.53, with corresponding revisions to § 75.73(c)(3) (for sources reporting NO_X mass emissions under Subpart H) and to § 75.84 (for sources reporting Hg mass emissions under Subpart I).

EPA proposed to add two new paragraphs, (g) and (h), to § 75.53, which describe the required monitoring plan data elements in EPA's re-engineered XML data structure. Under this proposal, the provisions of paragraphs (g) and (h) would be followed instead of the existing recordkeeping requirements of paragraphs (e) and (f), on and after January 1, 2009. In 2008, sources would be allowed to choose between the EDR format and XML, but new sources reporting for the first time in 2008 would be strongly encouraged to use the XML format. Included among the proposed monitoring plan changes would be mandatory recording and reporting of the key rectangular duct wall effects data elements using these record types. The proposed requirements to record and report the results of wall effects adjustment factor (WAF) determinations in the monitoring plan are found in §§ 75.53 (e) and (g) and in § 75.64.

EPA also proposed to make a series of modifications to §§ 75.58 and 75.59 to support the new XML data structure. The proposed changes to the monitoring plan and recordkeeping sections were presented, section-by-section, in Tables 1, 2, and 3 in the preamble to the August 22, 2006 proposed rule.

Summary of Rule Changes

No significant adverse comments were received on the proposed changes and they have been finalized.

1. Other Reporting Issues

a. Long-Term Cold Storage and Deferred Units

Background

EPA proposed changes to Part 75 to clarify the meaning of the term ''long-term cold storage (LTCS)'', found in § 75.4(d). First, a proposed definition of long-term cold storage would be added to § 72.2. LTCS would mean that the unit has been completely shut down and placed in storage and that the shutdown is intended to last for an extended period of time (at least two calendar years). Second, the Agency proposed to add a new paragraph, (a)(7), to § 75.61, requiring the owner or operator to provide notifications when a unit is placed in LTCS and when the unit re-commences operation. Third, modifications to § 75.20(b) were proposed, requiring recertification of all monitoring systems when a unit re-commences operations after a period of long-term cold storage. If a source claiming LTCS status re-commenced operation sooner than two years after being placed in LTCS, the notification and recertification requirements would apply. Fourth, the proposed rule would exempt a unit in LTCS from quarterly emissions reporting under § 75.64 until the unit recommences operation. Parallel LTCS rule provisions and appropriate cross-references regarding quarterly reporting requirements for Subpart H and Subpart I units would be added to §§ 75.73(f)(1) and 75.84(f)(1), respectively, for consistency.

EPA also proposed to revise the provisions of §§ 75.4(d) and 75.61(a)(3) pertaining to ''deferred'' units, i.e., units for which a planned or unplanned outage prevents the required continuous monitoring systems from being certified by the compliance date. The proposed revisions would broaden the scope of § 75.4(d) beyond the Acid Rain Program, to include units in State or Federal pollutant mass emissions reduction programs that adopt the monitoring and reporting provisions of Part 75. Examples of such programs include the Clean Air Interstate Regulation (CAIR), which is scheduled to begin in 2008 and the Clean Air Mercury Regulation (CAMR), which goes into effect in 2009. The proposed revisions to §§ 75.4(d) and 75.61(a)(3) were deemed necessary because the CAIR and CAMR rules do not address deferred units.

The proposed revisions to § 75.4(d) would require the owner or operator of a deferred unit to provide notice of unit shutdown and recommencement of commercial operation, either according to § 75.61(a)(3) (for planned shutdowns such as scheduled maintenance outages and for unplanned, forced unit outages) or § 75.61(a)(7) (for units in long-term cold storage). For all of these circumstances involving deferred units, EPA proposed that the Part 75 continuous monitoring systems would have to be certified within 90 unit operating days or 180 calendar days (whichever comes first) of the date that the unit recommences commercial operation. In the time interval between the unit re-start and the completion of the required certification tests, the owner or operator would be required to report emissions data, using either: (1) Maximum potential values; (2) the conditional data validation procedures of § 75.20(b)(3); (3) EPA reference methods; or (4) another procedure approved by petition to the Administrator under § 75.66. Finally, the Agency proposed to revise the notification requirements of § 75.61(a)(3) to be consistent with the proposed changes to § 75.4(d).

Summary of Rule Changes

Commenters were generally supportive of the proposed long-term cold storage provisions, requesting only minor clarifications. These provisions have been finalized with no substantive changes. One commenter encouraged EPA to adopt the proposed amendments to broaden the scope of § 75.4(d), to ensure that deferred units under programs such as CAIR and CAMR are provided with a reasonable window of time in which to certify the required monitoring systems, when the units resume operation. EPA has finalized these amendments to § 75.4(d), as proposed.

b. Notice of Initial Certification Deadline

Background

EPA proposed to add a new paragraph (a)(8) to § 75.61, to require new and newly affected sources to notify EPA when the monitoring system certification deadline is reached. Depending on the program(s) to which the unit is subject, this date will always be a particular number of calendar days or unit operating days after a unit either:

(a) Commences commercial operation; (b) commences operation; or (c) becomes an affected unit. For Acid Rain Program sources, the Agency must know this date to correctly assess when to begin counting emissions against allowances pursuant to § 72.9. Knowing this date also confirms that the monitoring systems either have or have not been certified by the legal deadline.

Summary of Rule Changes

One commenter asserted that the requirement for sources to submit to EPA a notification of the deadline for initial monitoring system certification is unnecessarily burdensome and should not be incorporated into Part 75. Another commenter requested that the information be reported in the electronic monitoring plan, rather than requiring a separate notification. EPA does not agree that reporting this information will be burdensome or that it is appropriate to report the date of the initial certification deadline in the electronic monitoring plan. Rather, this date is an essential data element that will be managed using the web-based CAMD Business System (CBS). Therefore, the notification requirement can be met electronically using the CBS. In view of this, the amendment to § 75.61 has been finalized, as proposed.

c. Monitoring Plan Submittal Deadline

Background

EPA proposed to amend § 75.62(a) by changing the submittal deadline for the initial monitoring plan for new and newly-affected units from 45 days to 21 days prior to the initial certification testing, in order to synchronize the initial monitoring plan submittal with the initial test notice. Corresponding changes to Subpart H (§ 75.73(e)) and to Subpart I (§ 75.84(e)) were proposed, for consistency.

EPA also proposed to remove the requirement from § 75.62(a)(1) that the electronic monitoring plan must be submitted ''in each electronic quarterly report''. Rather, inclusion of the monitoring plan in the report would be optional, and monitoring plan updates would be made either prior to or concurrent with (but not later than) the date of submission of the quarterly report. These proposed revisions would allow sources to maintain their monitoring plan information separate from the quarterly report, but this option would only be available to sources reporting in the new XML format under the re-engineered data submission process.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and they have been finalized, as proposed.

d. EPA Form 7610–14

Background

EPA proposed to amend §§ 75.63(a)(1) and (a)(2), to remove the requirement to submit hardcopy EPA form 7610–14 along with every certification or recertification application. Significant upgrades to EPA's data systems have been made in recent years, and Form 7610–14 is no longer needed to process these applications.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and they have been finalized, as proposed.

e. LME Applications

Background

EPA proposed to remove the requirement from § 75.63(a)(1)(ii)(A) for a hardcopy LME certification application to be submitted to the Administrator. The proposal would require only the electronic portion of the application, including the monitoring plan and LME qualification records, to be sent to EPA's Clean Air Markets Division. The hardcopy portion of the LME application would be sent to the State and to the EPA Regional Office.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and they have been finalized, as proposed.

f. Reporting Test Data for Diagnostic Events

Background

EPA proposed to revise § 75.63(a)(2)(iii) to make the reporting of the results of diagnostic tests more flexible. Rather than requiring these test results to be reported in the electronic quarterly report for the quarter in which the tests are performed, they could either be submitted prior to or concurrent with that quarterly report. However, this proposed flexibility in the reporting of diagnostic test results would only be available to sources reporting in the new XML format under the re-engineered data submission process.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and they have been finalized, as proposed.

g. Modifications to § 75.64

Background

As part of its data systems re-engineering effort, EPA proposed to revise § 75.64(a) to describe the transition from the existing EDR reporting requirements to the reporting requirements of the new XML format. The Agency proposed to renumber several paragraphs, to replace paragraphs (a)(1) and (a)(2) with new paragraphs (a)(3) through (a)(7), and to remove existing paragraph (a)(8).

Summary of Rule Changes

No adverse comments were received on these proposed rule changes. These amendments to § 75.64(a) have been finalized, as proposed.

h. Steam Load Reporting

Background

EPA proposed to add a third option to Part 75 for reporting load data in units of mmBtu/hr of steam thermal output. This option is needed to accommodate emissions trading programs in which allowance allocations are made on an electrical or thermal output basis, rather than a heat input basis. The Agency proposed to add text to several sections in the main body of Part 75 and to the Appendices, to accommodate the new reporting option.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and they have been finalized, as proposed.

i. Test Notification Requirements—Hg Low Mass Emission Units

Background

Section 75.61(a)(5) requires the owner or operator or the designated representative to provide 21-day advance notice for various periodic quality-assurance tests, including the semiannual or annual relative accuracy tests of CEMS, and for the re-tests of Appendix E peaking units and low mass emissions (LME) units. Test notices must be provided to the Administrator, to the appropriate EPA Regional Office and to the State or local agency (unless a particular agency issues a waiver from the requirement).

Under Subpart I of Part 75, certain low-emitting units covered by the Clean Air Mercury Regulation (CAMR) may qualify under §§ 75.81(b) through (d) to perform periodic (semiannual or annual) Hg emission testing in lieu of operating and maintaining continuous Hg monitoring systems. EPA proposed to expand the notification requirements of § 75.61(a)(5) and to add

corresponding introductory text to § 75.61(a)(1), requiring the owner or operator or the designated representative to provide at least 21 days notice of the scheduled dates of these periodic Hg emission tests.

Summary of Rule Changes

No adverse comments were received on this proposed rule change and this test notification requirement has been finalized, as proposed.

j. Hardcopy Reports for Retests of Hg Low Mass Emission Units

Background

Sections 75.60(b)(6) and (b)(7) require the designated representative (DR) to submit the results of certain periodic quality-assurance tests to the appropriate EPA Regional Office or to the State or local agency, when the test results are requested in writing (or by electronic mail). In particular, the results of semiannual or annual RATAs of CEMS and the routine re-tests of Appendix E units may be requested. If requested, the test results must be submitted within 45 days after the test is completed or within 15 days of the request, whichever is later. EPA proposed to add a new paragraph (b)(8) to § 75.60, requiring the DR to provide, upon request from EPA or the State, the results of the semiannual or annual Hg emission tests required under § 75.81(d)(4) for low-emitting units covered by CAMR. The proposed time frame for submitting these Hg emission test results would be the same as the current one for the RATAs and Appendix E re-tests.

Summary of Rule Changes

No adverse comments were received and this provision has been finalized, as proposed.

k. Wall Effects Adjustment Factors

Background

For sources with flow monitors installed on circular stacks, reporting of wall effects information is currently required by §§ 75.64(a)(2)(xiii), 75.73(f)(1)(ii)(K) and 75.84(f)(1)(ii)(I), when Method 2H is used in conjunction with Method 2, 2F or 2G. The specific wall effects data elements that must be reported are found in § 75.59(a)(7)(ii) and (a)(7)(iii). These data are submitted along with flow RATA results, as supplementary information.

For rectangular stacks and ducts, some of the same supporting data elements in § 75.59(a)(7)(ii) and (a)(7)(iii) are needed for flow RATAs performed using Method 2F or 2G, when wall effects corrections are applied. Additional supporting data elements, not in the current rule, are also needed for Method 2 flow RATAs when wall effects adjustments are made. In view of this, EPA proposed to revise the text of §§ 75.64(a)(2)(xiii), 75.73(f)(1)(ii)(K) and 75.84(f)(1)(ii)(I) and to add RATA support data elements to a new paragraph, (vii), in § 75.59(a)(7), to clarify which wall effects data elements must be reported for circular stacks, which ones are reported for rectangular stacks and ducts, and which data elements must be reported for both types of stacks.

Summary of Rule Changes

No adverse comments were received on these proposed rule changes and they have been finalized, as proposed.

F. Subpart H (NO_X Mass Emissions)

1. Subpart H Diluent Monitoring Systems

Background

For coal-fired Subpart H units that calculate NO_X mass emissions as the product of NO_X concentration and flow rate and are required to monitor and report the unit heat input, § 75.71(a)(2) requires the installation of an ''O_2 or CO_2 diluent gas monitor''. Consistent with the definition of a CEMS in § 72.2, this diluent monitor, which is only used for the heat input determination, should be described as an ''O_2 or CO_2 monitoring system''. EPA proposed to revise the text of § 75.71(a)(2) accordingly.

Summary of Rule Changes

No adverse comments were received. This clarification of § 75.71(a)(2) has been finalized, as proposed.

2. Identifying a NO_X Mass Methodology

Background

EPA proposed to revise § 75.72 to require that only one NO_X mass emissions methodology be identified in the monitoring plan at any given time, and to disallow the designation of primary and secondary NO_X mass calculation methodologies. EPA believes that one methodology for NO_X mass emissions is sufficient. If a source is subject to both Subpart H and to the Acid Rain Program (ARP) and is concerned about losing NO_X data when the diluent component of the NO_X emission rate system is out-of-control, that source should choose the NO_X concentration times flow rate calculation method as the NO_X mass calculation methodology. This would require a NO_X concentration system to be identified in the monitoring plan, in addition to the NO_X emission rate system. The NO_X concentration system would be used only to determine NO_X mass emissions, and the NO_X emission rate system would be used only to meet the ARP requirement to report NO_X in lb/mmBtu.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

3. Reporting of Subpart H Facility Information

Background

Consistent with the proposed revisions to § 75.64, EPA proposed to revise § 75.73(f)(1), to phase out the requirement of § 75.73(f)(1)(i)(B) to include facility location information in each quarterly report.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

4. Linearity Check Requirements for Ozone Season-Only Reporters

Background

For Subpart H sources that report emissions data on an ozone season-only (OSO) basis, EPA proposed to revise the linearity check provisions in § 75.74(c)(2), (c)(2)(i), (c)(2)(ii), (c)(3)(ii), (c)(3)(vi), and (c)(3)(viii). Historically, OSO reporters have been required to do a pre-season linearity check, an in-season second quarter linearity check (in May or June, if the unit operates for ≥ 168 hours in May and June), and a third quarter linearity check, if the unit operates for ≥ 168 hours in that quarter. Many sources have misunderstood these rule provisions, particularly the requirement to perform an in-season linearity check in the second quarter. In some cases, this has resulted in CEMS out-of-control periods and has required the use of missing data substitution. OSO reporters have also been required to operate and maintain each CEMS and to perform daily calibration error tests, in the time period extending from the hour of completion of the pre-season linearity check through April 30. EPA has found that this rule provision is also not well-understood by the affected sources and assessing compliance with the provision has been difficult, since sources have not been required to report the results of any off-season calibration error tests done prior to April.

In view of these considerations, EPA proposed to revise § 75.74(c)(2) to require the pre-season linearity checks to be conducted in the month of April, and to delete all references to

performing the pre-season linearity checks at other times. The Agency also proposed to remove the conditional grace period provision from § 75.74(c)(2)(i)(D), and to address (in § 75.74(c)(3)(ii)(E)) data validation in the case where the April linearity check is not completed prior to the start of the ozone season. In that case, data from the monitor would be considered invalid as of May 1, unless the conditional data validation procedures of § 75.20(b)(3) are applied. A 168 unit operating hour period of conditional data validation would be allowed, in which to perform the required linearity check. Passing the linearity check on the first attempt within the allotted time would result in the conditionally valid data becoming quality-assured. Failing the linearity check would result in all data from the monitor be invalidated back to the beginning of the ozone season and the data would remain invalid until a linearity check is passed. Performing the linearity check after the 168-hour period expires would require the data validation provisions in § 75.20(b)(3)(viii) to be applied, subject to the restrictions of § 75.74(c)(3)(xii).

EPA proposed to add a new paragraph (F) to § 75.74(c)(3)(ii), stating that a pre-season linearity check done in April fulfills the second quarter linearity check requirement, and to remove and reserve related Section 75.74(c)(3)(viii). Further, proposed § 75.74(c)(3)(ii)(B) would require the third quarter linearity check to be conducted either by July 30 or within a 168 operating hour period of conditional data validation thereafter. Finally, the Agency proposed that § 75.74(c)(3)(ii)(G) would address the case where a unit operates infrequently and the 168 operating hour conditional data validation period associated with the April linearity check extends through the second quarter, into the third quarter. In that case, if a linearity check is performed and passed in the third quarter, before the 168 operating hour window expires, EPA proposed that this one linearity check would satisfy all three of the ozone season linearity check requirements, i.e., for the pre-season, for the second quarter, and for the third quarter.

Summary of Rule Changes

The amendments to § 75.74(c) have been finalized, as proposed. Commenters supported EPA's proposal to allow a linearity check performed in April to satisfy both the pre-season and second quarter linearity check requirements. However, several commenters requested that the Agency allow greater flexibility in the timing of the required linearity checks. The proposed amendments requiring the pre-season linearity check to be performed April and the 3rd quarter test to be done in July were perceived as being too restrictive. EPA does not agree with these commenters that the revised quality assurance requirements for ozone season-only reporters lack flexibility. The amendments allow sources to use conditional data validation for up to 168 unit or stack operating hours, in situations where the linearity check cannot be completed by the prescribed deadline. If the required test is performed and passed within the allotted window of time, the source will incur no data loss. OSO reporters desiring greater flexibility in scheduling quality assurance tests should seriously consider switching to year-round reporting. Doing so would provide many benefits, such as grace periods, test deadline extensions, and in some cases, test exemptions.

5. RATA Requirements for Ozone Season Only Reporters

Background

For Subpart H sources that report NO_X mass emission data on an ozone season-only (OSO) basis, Part 75 has required, for quality-assurance purposes, that at the start of each ozone season each required CEMS must be within the ''window'' of data validation of a current, non-expired RATA. In past years, this requirement has been met either by performing a RATA in the pre-season (between October 1 and April 30) or, in some instances, by relying on the results of a RATA done in the previous ozone season. The rule has further required each CEMS to be operated, calibrated and maintained in the time period extending from the completion of the RATA, through April 30. Many sources choosing the OSO reporting option find this operation and maintenance (O&M) requirement to be counter intuitive, because they expect to be required to meet Part 75 monitoring obligations only during the ozone season.

In view of these considerations, EPA proposed to restrict the window of time in which pre-season RATAs may be performed. As proposed, § 75.74(c)(2)(ii) would require the RATAs to be done either in the first quarter of the year or in the month of April. That restriction would prohibit RATAs done in the previous year from being used to validate data in the current ozone season.

EPA also proposed to revise § 75.74(c)(2)(ii)(F), to address data validation. The proposed data validation rules for RATAs are similar to those proposed for linearity checks, in that a period of conditional data validation (720 operating hours) would be allowed when the pre-season RATA is not completed by the April 30th deadline. Consistent with these revisions, the Agency proposed to delete the data validation and conditional grace period provisions in § 75.74(c)(2)(ii)(G) and (c)(2)(ii)(H) and to remove and reserve § 75.74(c)(3)(vi), (vii), and (viii).

Summary of Rule Changes

The amendments to § 75.74(c) have been finalized, as proposed. One commenter objected to the proposed restriction on the timing of the RATAs and requested that the existing flexibility in the rule be retained. The commenter expressed a strong preference to perform RATAs in the autumn, rather than in the January-April time frame proposed by EPA. A second commenter stated that EPA should remove the requirement to keep records of off-season daily calibration and interference check records in a format suitable for inspection from § 75.74(c)(2)(ii)(E)(*1*).

Regarding the first commenter's assertion that the proposed RATA time frame for OSO reporters is too restrictive, EPA recommends that the owner or operator seriously consider switching to year-round reporting. Year-round reporting allows complete freedom to schedule RATAs at any convenient time during the year and provides many benefits, such as grace periods, test deadline extensions, and in some cases, test exemptions. Even if EPA had decided not to amend the RATA provisions for OSO reporters, § 75.74(c)(2)(ii)(E)(*1*) would still require the CEMS to be operated, maintained and calibrated in the time period between the RATA and the start of the next ozone season. Thus, if the RATAs are performed in the autumn (e.g., November), the CEMS would have to be maintained and calibrated for at least 10 months of the year; in this case, OSO reporting offers no clear advantage over year-round reporting.

EPA did not incorporate the second commenter's suggestion to remove the recordkeeping requirement from § 75.74(c)(2)(ii)(E)(*1*). However, the text of § 75.74(c)(6)(iii) has been revised to remove the requirement to report the daily calibrations and interference checks done in the month of April. The requirement to record these data remains intact, but the reporting has been made optional.

6. Determining Peaking Status for Ozone Season Only Reporters

Background

EPA proposed to revise § 75.74(c)(11) to clarify that when peaking unit status for ozone season-only reporters is determined, 3,672 hours (i.e., the number of hours in the ozone season) should be used instead of 8,760 hours in the capacity factor equation.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

7. Calculation of Ozone Season NO_X Mass Emissions—LME Units

Background

EPA proposed to correct an organizational error in Subpart H of Part 75. The proposal would remove § 75.72(f), which describes ozone season NO_X mass calculations for units using the low mass emission (LME) methodology under § 75.19, and the basic content of § 75.72(f) would be relocated to § 75.71(e). The LME provision in § 75.72 appears to have been inadvertently placed in that section. The monitoring provisions of § 75.72 apply to common and multiple stack configurations, whereas § 75.71 addresses unit-level monitoring. LME is a unit-level monitoring methodology.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

G. Subpart I (Hg Mass Emissions)

1. Heat Input Provisions for Common and Multiple Stacks

Background

Due to an apparent oversight, the heat input monitoring provisions for certain monitoring configurations in Subpart I of Part 75 were inadvertently omitted when Subpart I was promulgated. In particular, EPA found the heat input methodologies for common stacks shared by affected and non-affected units and for multiple stack or duct configurations to be missing. In view of this, the Agency proposed to add three new paragraphs, (b)(3), (c)(4) and (d)(3) to § 75.82 to correct this deficiency.

For the common stack shared by affected and non-affected units, proposed § 75.82(b)(3) would require the owner or operator to either measure the total heat input rate at the common stack and apportion it to the individual units by load, according to § 75.16(e)(3), or to determine the heat input rate at the individual units by installing a flow monitor and a diluent monitor on the duct leading from each unit to the common stack. For multiple stack configurations, proposed § 75.82(c)(4) and (d)(3) would require the owner or operator to determine the hourly unit heat input by measuring the hourly heat input rate (mmBtu/hr) at each stack, multiplying each stack heat input rate by the stack operating time (hr) to convert it to heat input (mmBtu), and then summing the hourly stack heat input values.

Summary of Rule Changes

No adverse comments were received. These provisions have been finalized, as proposed.

2. Low Mass Emission Alternative

Background

Section 75.81(b) of Subpart I provides an alternative (''excepted'') monitoring methodology for units with low Hg mass emissions. To qualify to use this methodology, emission testing is required to demonstrate that the unit has the potential to emit no more than 29 lb (464 ounces) of Hg per year. Once a unit qualifies, periodic retesting (semiannual or annual, depending on the emission level) is required to demonstrate that the unit is actually emitting less than 29 lb/yr of Hg.

Section 75.81(e), as originally published, allowed the low mass emission alternative to be used for common stacks, provided that the units sharing the stack are tested individually and each one qualifies as a low-emitter. Though not explicitly stated in the rule, it was implied that the periodic retests for common stack configurations would also have to be done at the unit level. EPA has reconsidered this approach, believing it to be overly restrictive, unnecessarily difficult, and costly to implement.

Therefore, EPA proposed to revise § 75.81(e) to require Hg testing of the individual units that share the common stack only for the initial demonstration that the units individually qualify as low emitters. Once this has been satisfactorily demonstrated, the required semiannual or annual retests could then be done at the common stack, at a normal load level for the configuration.

The proposed revisions to § 75.81(e) would also allow the initial low mass emitter qualification for a group of identical units sharing a common stack to be based on emission testing of a subset of those units. To exercise this proposed option, the group of units would first have to qualify as identical under § 75.19(c)(1)(iv)(B). Then, the number of units required to be tested would be determined from Table LM–4 in § 75.19.

The proposed amendments allowed one exception to the requirement to test the individual units sharing a common stack, in order to demonstrate that the units qualify for low mass emitter status, i.e., the case where the gas streams from the individual units are combined together and routed through emission controls that reduce the Hg concentration (e.g., a wet scrubber) before entering the common stack. Owners or operators electing to use this option would be required to perform the testing with all of the units that share the stack in operation, and the combined load during the testing would have to be ''normal'', as defined in Section 6.5.2.1 of Appendix A.

EPA also proposed to revise § 75.81(c)(1), to specify the acceptable time frame in which to perform the initial certification testing for the low mass emission option. As originally published, the rule simply states that this testing must be done ''prior to the compliance date in § 75.80(b)'', but does not specify how far in advance of that date the testing may be done and still be considered acceptable. Further, § 75.81(d)(1) requires the test results to be submitted as a certification application, no later than 45 days after completing the testing. And § 75.81(d)(4) requires periodic Hg retesting to commence within two or four ''QA operating quarters'' after the quarter of the certification testing.

If there is too long a gap between the certification testing and the start of the program, it becomes problematic. For instance, if the testing is done too early, the requirement to submit a certification application within 45 days could result in applications being submitted long before the regulatory agencies are ready to receive and process them. Also, the periodic retesting requirements of § 75.81(d)(4), which become active on the certification test date, could result in several Hg retests being done before the program begins. This is clearly contrary to the purpose of the retests, which, like the periodic relative accuracy tests of CEMS, are intended to commence after the compliance date, when Hg emissions reporting has begun. This also raises questions about which default emission rate to use for the initial reporting. In view of these considerations, EPA proposed to revise § 75.81(c)(1), to require that the Hg testing for initial certification be done no more than 1 year before the compliance date. Sections 75.81(d)(2) and 75.81(d)(5) would also be revised, to address the case where a retest may be required before the compliance date

(e.g., when § 75.81(d)(4) requires a retest within two QA operating quarters, following a certification test that was done 9 to 12 months before the compliance date). In such cases, the default Hg emission rate used at the beginning of the program would be the value that was obtained in the retest.

Finally, EPA proposed to amend §§ 75.81(d)(4) and (d)(5) to address the emission testing requirements when the fuel supply is changed. The proposed revisions would require additional Hg retesting within 720 unit operating hours, following a change in the fuel supply. The results of this retest would then be applied retrospectively, back to the time of the fuel switch. The Agency also proposed to revise § 75.81(c)(1) to require that the fuel combusted during the initial certification testing be from the same source of supply as the fuel combusted when the program starts. The proposed revisions only addressed the emission testing and reporting requirements for one case, i.e., where the source of supply for the primary fuel (assumed to be coal) changes. EPA solicited comments and suggestions on how to apply the Hg low mass emitter option in situations where the coal supply does not change, but the unit sometimes burns other types of fuel besides coal or co-fires mixtures of coal and other fuels (i.e., what emission testing and reporting requirements might be appropriate).

Summary of Rule Changes

Commenters were generally supportive of the proposed amendments that would reduce the testing requirements for Hg low mass emission units in common stack configurations. The final rule differs somewhat from the proposal, however, in that it also allows the initial qualifying test to be performed at the common stack, if certain conditions are met. The conditions are: (1) Testing must be done at a combined load corresponding to the designated normal load level (low, mid, or high) defined in the monitoring plan; (2) all of the units that share the stack must be operating in a normal, stable manner and at typical load levels during the emission testing; (3) the coal combusted in each unit during the testing must be representative of the coal that will be combusted in that unit at the start of the Hg mass emission reduction program (preferably from the same source(s) of supply); and (4) if flue gas desulfurization and/or add-on Hg emission controls are used to reduce the level of emissions exiting from the common stack, these emission controls must be operating normally during the emission testing and the owner or operator must record parametric data or SO_2 concentration data in accordance with § 75.58(b)(3)(i) to document proper operation of the controls.

For retests, provided that the required load level is attained and that all of the units sharing the stack are fed from the same on-site coal supply during normal operation, it is not necessary for all of the units sharing the stack to be in operation during a retest. However, if two or more of the units that share the stack are fed from different on-site coal supplies (e.g., one unit burns low-sulfur coal for compliance and the other combusts higher-sulfur coal), then the owner or operator must either: (1) Perform the retest with all units in normal operation; or (2) if this is not possible, due to circumstances beyond the control of the owner or operator (e.g., a forced unit outage), perform the retest with the available units operating and assess the test results as follows. The Hg concentration obtained in the retest is used for reporting purposes if the concentration is greater than or equal to the value obtained in the most recent test. However, if the retested value is lower than the Hg concentration from the previous test, then the higher value from the previous test continues to be used for reporting purposes, and that same higher Hg concentration is used in Equation 1 to determine the due date for the next retest.

The final rule expands the testing of groups of identical units beyond identical units that share a common stack. Section 75.81(c)(1)(iv) has been amended to allow a subset of any group of identical units to be tested according to Table LM–4 in § 75.19, whether or not the units share a common stack. This amendment is modeled after the provisions of § 75.19(c)(1)(iv)(B) for testing groups of identical LME units.

Several commenters objected to the proposed requirement to perform retesting of low mass emission units when the fuel supply is changed. Concerns were expressed that the term ''change in fuel supply'' is not clearly defined and could be interpreted to require frequent, unnecessary retesting, especially in light of the variation in coal supplies from day to day in competitive wholesale power markets. A number of the commenters recommended that retesting be limited to changes in coal rank or classification (e.g., changing from bituminous coal to sub-bituminous coal). EPA has incorporated the commenters' suggestion into the final rule. Section 75.81(d)(4) of the final rule clarifies what constitutes a ''change in fuel supply'' that will trigger LME retesting. If a unit switches to a different rank of coal as the primary fuel for the unit, in-between the scheduled LME retests (where coal rank is defined by ASTM D388–99), an additional LME retest is required within 720 operating hours of the change. The results of this retest are then applied retrospectively back to the date and hour of the fuel switch. The four principal coal ranks are anthracitic, bituminous, subbituminous, and lignitic. The ranks of anthracite coal refuse (culm) and bituminous coal refuse (gob) are considered to be anthracitic and bituminous, respectively.

Equation 1 in § 75.81(c)(2), which is used to demonstrate that a unit qualifies as a Hg low mass emissions unit, conservatively estimates the unit's potential annual Hg emissions by assuming that it operates at the maximum potential flow rate for 8,760 hours per year. One commenter requested that EPA consider modifying Equation 1 to conditionally allow a number of hours less than 8,760 to be used in the calculations, the condition being that there is a Federally-enforceable permit provision in place, limiting the unit's annual operating hours. EPA has incorporated this suggestion into the final rule. The term ''8,760'' in Equation 1 has been replaced with ''N'', which will either be 8,760 or the maximum number of operating hours per year allowed by the unit's Federally-enforceable operating permit (if less than 8,760). If the operating permit restricts the unit's annual heat input but not the number of annual unit operating hours, the owner or operator may divide the allowable annual heat input (mmBtu) by the design rated heat input capacity of the unit (mmBtu/hr) to determine the value of ''N''.

Finally, no comments were received on the proposal to require that the Hg emission testing for initial certification of a low mass emission unit be done no more than 1 year prior to the applicable compliance date. Therefore, this provision has been finalized, as proposed. For units subject to the Clean Air Mercury Regulation (CAMR), the certification deadline is January 1, 2009. In view of this, only those Hg emission tests of candidate low mass emission units that are performed on and after January 1, 2008 will be accepted for initial certification.

3. Harmonization of Subpart I With Other Proposed Rule Revisions

Background

Subpart I of Part 75 also contains a recordkeeping and reporting section (§ 75.84). which, for the most part, cross-references the primary monitoring

plan, recordkeeping, notification and reporting sections of the rule (i.e., §§ 75.53, 75.57 through 75.59, 75.61, and 75.64) and other sections of Subpart I.

To make Subpart I consistent with the proposed revisions to the monitoring plan, recordkeeping, notification, and reporting sections of Part 75, EPA proposed to make a number of minor adjustments to the text of §§ 75.84(c)(3), (e)(1), (e)(2), and (f)(1).

Summary of Rule Changes

No adverse comments were received. These provisions have been finalized, as proposed.

H. Appendix A

1. CO_2 Span Values

Background

EPA proposed to revise Section 2.1.3 of Appendix A, to allow the use of CO_2 spans less than 6.0 percent CO_2 if a technical justification is provided in the hardcopy monitoring plan. This added flexibility in the CO_2 span value mirrors a similar provision in Section 2.1.3 for O_2 span values.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

2. Protocol Gas Audit Program

Background

EPA is responsible for implementing air quality programs that rely heavily on the accuracy of calibration gas standards. Section 2.1.10 of ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards'' (Protocol Procedures), September 1997 (EPA–600/R–97/121) states that EPA will periodically assess the accuracy of calibration gases and publish the results. Between 1978 and 1996, EPA conducted several performance audits of calibration gases from various manufacturers. One notable result of these audits was a steady, significant reduction in the failure rate of the audited gas cylinders, from about 27% in 1992 down to 5% in 1996. The annual audits were discontinued after 1996. Then, in 2003, EPA conducted a ''surprise'' audit of 14 national specialty gas producers and found that the failure rate had risen to 11%.

In view of this, EPA proposed to establish a Protocol Gas Verification Program (PGVP) and would require that EPA Protocol Gases being used for 40 CFR Part 75 purposes be obtained from specialty gas producers who participate in the PGVP. As proposed, the rule would allow only program participants to market their gas standards as ''EPA Protocol Gases.'' EPA proposed to maintain a web site, listing the PGVP participants and the audit results, in order to provide calibration gas users with detailed information about the quality of EPA Protocol Gases.

EPA also proposed to: (1) Add a definition of ''specialty gas producer'' to § 72.2; (2) delete several calibration gas standards and reference materials from section 5.1 of appendix A (believing them to be prohibitively expensive and not used in practice by Part 75 sources); (3) remove from § 72.2 the corresponding definitions of the deleted calibration gas standards; and (4) consolidate the remaining calibration gas standards under section 5.1 of appendix A.

Finally, EPA requested comment on the appropriate accuracy specification to apply to Hg cylinder gases and other Hg calibration standards (e.g., gases from NIST-traceable generators). Currently, EPA requires that accuracy of other EPA Protocol gases to be within 2 percent of the certified tag values.

Summary of Rule Changes

Only one organization commented on the proposed protocol gas verification program (PGVP). The commenter stated that a transition period is needed to implement the program. Sources need time to communicate with their gas vendors regarding their participation in the PGVP. The commenter further asserted that the PGVP would be disruptive and costly, both in the short-term and in the long-term, and that the affected sources would bear the brunt of the cost impact.

EPA agrees with the commenter regarding the need for a transition period. The final rule amends section 5.1.4 (c) to have the Protocol Gas Verification Program (PGVP) take effect on January 1, 2009. As the commenter has stated, the costs of the PGVP will be borne by the Part 75 sources using the calibration gases, and the Agency notes that these minimal costs ($5 to $10 added to a $500 to $1,000 cylinder) will be offset by the savings generated by fewer failed calibration error tests, linearity checks, and relative accuracy test audits.

3. Requirements for Air Emission Testing Bodies

Background

Since the inception of the Acid Rain Program, field audits of Part 75-affected facilities have brought to EPA's attention a number of improperly-performed RATAs and other QA/QC tests. In view of this, EPA proposed to revise Section 6.1 of Appendix A to require all individuals who perform the emission tests and CEMS performance evaluations required by Part 75 to demonstrate conformance with ASTM D7036–04 ''Standard Practice for Competence of Air Emission Testing Bodies''. ASTM D7036–04 specifies the general requirements for demonstrating that an air emission testing body (AETB) is competent to perform emission tests of stationary sources.

Proposed revisions to Section 6.1.2 of Appendix A, Section 2.1 of Appendix E, and Section 1 of Appendix B make it clear that this requirement would apply only to AETBs that perform RATAs, NO_X emission tests of Appendix E and LME units, or Hg emission tests of low-emitting units. It would not be applicable to the daily operation, daily QA/QC (daily calibration error check, daily flow interference check, etc.), weekly QA/QC (i.e., Hg system integrity checks), quarterly QA/QC (linearity checks, etc.), and routine maintenance of the CEMS.

EPA also proposed to incorporate ASTM Method D7036–04 by reference in § 75.6(a)(45), and to add a definition of ''Air Emission Testing Body'' to § 72.2.

Summary of Rule Changes

The amendments to Section 6.1.2 of Appendix A, Section 2.1 of Appendix E, and to Section 1 of Appendix B, requiring AETBs to conform to ASTM D7036–04, have been finalized, as proposed. Two commenters strongly supported the proposed revisions. However, several others objected to them, believing they would be costly and burdensome, without producing any noticeable improvement in data quality. EPA does not agree with these commenters, for the following reasons.

The experience of the State and Federal regulators in the ASTM work group indicates that implementation of the ASTM Practice will result in improved data quality. EPA believes the evidence is abundant that unqualified, under-trained and inexperienced testers are often deployed on testing projects. The Agency has had experiences with tests that have been invalidated or called into question due to poor performance by testing contractors (see Docket Items OAR–2005–0132–0009, –0021, and –0035). Conformance with ASTM D7036–04 does not guarantee that every test will be performed properly. However, it will reduce the likelihood of problems. Furthermore, it provides a guideline for both regulatory agencies and affected sources to evaluate and select competent testing

firms. One of the cornerstones of the Practice is that AETBs must collect performance data on how well they plan and execute test projects. These data must be shared with regulators and clients upon request.

In response to claims that ASTM D7036–04 will significantly increase the cost and burden of Part 75 testing, EPA notes that no data were provided to support these claims. The ISO 17025 standard upon which the ASTM standard is based has been implemented in Europe for many years. Mark Elliot, Chairman of the Stack Testing Association (STA) of Great Britain, has provided the following information on the costs of their programs. Their certification program (for individuals) is called MCERTS.

- MCERTS testing fees: Level 1 $350; Level 2 $940
- Technical endorsements (1–4): $350 each

The Level 2 certification requires a personal interview with the applicant. Please note that according to Mr. Elliot, this program has been successfully implemented in the UK with no small companies going out of business and no complaints of being overly burdensome on industry. In fact, many large companies such as Mobil, Dow, Pfizer, and 3M are members of the STA and fully support the program because, according to Mr. Elliot, they believe it improves the quality of the data provided by testing companies. Even major UK utility companies such as Drax Power, Energy Power Resources, the Electricity Supply Board, PB Power, Scottish and Southern Energy, and Scottish Power participate in the program. And they do this voluntarily because they have found it to their benefit to do so.

There are several differences between the program described in the final rule and the UK program. First, the final rule does not require accreditation. The individual testing requirements in the rule are less expensive and less stringent than the UK program. In the US, The Source Evaluation Society is currently providing Qualified Individual testing. The fees are $155 for the first test (including a one-time $15 SES membership) and $89 for any subsequent tests taken during the same testing session). It should also be noted that ASTM D7036–04 does not require that every individual be tested. Only one ''Qualified Individual'' need be present on-site during a test. Therefore, even this minimal cost and burden is considerably less than the successful UK program.

The costs of coming into initial compliance with the ASTM D7036–04 standard depend on the current state of an AETB's quality program. Those that do not currently have an organized quality program will most likely incur greater costs than those who do. In any case, the burden will be no greater than that experienced by the UK companies who successfully went through the same process.

The main costs to comply with the ASTM D7036–04 standard are associated with taking a stack test QSTI (qualified stack test individual) competency exam, and developing or revising a quality assurance (QA) manual. A nationwide compliance cost estimate may be obtained using the following estimates:

- 450 stack test companies in U.S. (The number of private (external) stack test companies came from *www.epa.gov/ttn/emc/software.html#testfirm*. RMB Consulting, Inc. estimated 10 in-house utility RATA test teams in the U.S.);
- On average, 10 people per company (Source: *www.epa.gov/ttn/emc/software.html#testfirm*);
- QSTI exam (required by ASTM) costs $150 and must be taken every 5 years (Source: December 11, 2006 letter from the Source Evaluation Society in Docket OAR–2005–0132); and
- Roughly 1 QSTI is required for every 3 people in a stack test company.

Using these inputs, the Agency estimates the cost to comply with ASTM D7036–04 at about $100 per yr per company to cover the QSTI exam. There is also approximately a $4,000 one time cost per company, whether a large or small entity as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201, to develop a QA manual (estimate provided by Air Tech, see Docket Item # EPA–HQ–OAR–2005–0132–0093). However, the costs will be borne by the Part 75 sources using the air emission testing bodies, and the Agency notes that these costs will be offset by the savings generated by fewer failed or incorrectly performed relative accuracy test audits, and fewer repeat tests required. Therefore, the effect of this revision is to actually relieve a regulatory burden on these entities.

Regarding the issue of the financial impact on smaller companies and the request to provide funds to these companies, EPA notes that small stack test companies were represented on the ASTM work group. At least one small stack test company (3 people) has already complied with ASTM D7036–04, is supportive of the requirement, and expects to actually realize an increase in business because of their compliance with ASTM D7036–04. As stated in another response, the costs to comply with ASTM D7036–04 are reasonable. Similar requirements have been successfully implemented for many years in the UK with no small companies going out of business and no complaints of being overly burdensome on industry. EPA does not expect to provide funds to support small stack test companies in meeting the requirements of ASTM D7036–04.

EPA notes that virtually the same program has been in place in Europe for several years and is functioning very well with the support of stack testers, the government, and industry. The ASTM standard is actually less stringent in some areas than the European program. Based on this extensive experience in Europe, EPA believes that this program can be successfully implemented here in the U.S. with very little additional burden. In summary, there is an abundance of both data and experience showing that this program can be implemented without an unreasonable burden, and also (according to UK industry participants) that it will improve the quality of data.

Two commenters asserted that the existing infrastructure is not adequate for testers to comply with the ASTM method. EPA disagrees with these claims. The Source Evaluation Society is currently offering qualification exams in several areas. The commenters may be concerned that the SES website used to state that their exams may not specifically satisfy the requirements of the ASTM Practice (because they were not developed specifically for that purpose). However, SES has updated the wording on their Web site to say that their qualification exams do meet the exam requirement of the ASTM Practice. The Stack Testing Accreditation Council (STAC) also recognizes that not only does the SES program meet the requirements of the ASTM standard—it actually exceeds them. It requires more experience than the ASTM standard and also requires letters of recommendation. Both EPA and STAC accept an SES certification as meeting the external testing and experience requirements of the ASTM Practice.

If an external QSTI test is not available to a company, an internal test may be used to meet the requirements of ASTM D7036–04 until an external test becomes available. EPA is aware of at least one large stack test company that has developed a training module for mercury methods meeting the requirements of the ASTM D7036–04, and has trained and tested their people according to the internal qualification exam provision of ASTM D7036–04. When a third party test becomes

available, this company has indicated that they will re-certify their people according to the requirements of ASTM D7036–04. The Source Evaluation Society is reviewing steps to improve and expand the QSTI examination process.

Four commenters asked EPA to clarify how compliance with ASTM D7036–04 would be determined. Section 6.1.2 in Appendix A of the final rule specifically states that there are two ways an AETB can certify compliance: (1) A certificate of accreditation, or (2) a letter of certification signed by senior management. The latter option is similar to the way major sources certify compliance with their Title V permits. However, AETBs are under much more direct regulatory scrutiny than a Title V source. Every state has a field test observer program. In the case of one large stack testing company, Clean Air Engineering, about half of their compliance tests are directly observed by state regulators. This oversight provides an on-going check of whether an AETB remains in conformance. In co-operation with the New Jersey DEP, a standardized state observer checklist is being developed that will facilitate incorporating state observer assessments into the ASTM process.

EPA expects to treat non-compliance with this standard in the same way it treats noncompliance with any other standard—using its enforcement discretion. EPA does not anticipate invalidating test results because of minor infractions. The proper way to deal with these issues, if either the regulatory authority or the client discovers them, is to notify the AETB that a problem has been found. The AETB is then obligated to initiate a corrective action to address the problem. This becomes part of the AETB's Performance Data required by the Practice. The Agency recommends that the client also ask the AETB to report back on what corrective actions were taken. In the case of serious infractions, EPA may exercise the same authority it has always had to reject the test.

EPA encounters deviations in test methodology routinely in reviewing stack test reports. Minor deviations are noted and reported back to the source but the underlying results are accepted. Major deviations result in a rejection of the test. This situation is no different. This Practice should be treated much like a test method in this regard. Minor deviations may be of the type the commenters cite in their examples. Major deviations may include (for example) not having a Qualified Individual on-site, not having proper calibration records for the equipment used, or failing to follow through with corrective actions when required.

There will undoubtedly be some discussions between EPA, affected sources and AETB's as this program unfolds that will help define the implementation of the Practice. But this is the case with every new rule and standard.

There is always a balance in standard writing between being overly detailed and prescriptive and being too loose and flexible. The stakeholders involved in the consensus process of ASTM determined that the proper balance had been achieved. It is important to keep in mind that ASTM D7036–04 is essentially an international standard that has been used successfully in countries all over the world.

Three commenters requested that EPA provide a 1–2 year transition period after promulgation of the final rule, to allow AETBs sufficient time to conform to ASTM D7036–04. Particular concerns were expressed about the availability of Qualified Individuals (QIs) for Hg emission testing. EPA agrees that a transition period is appropriate, given the testers' relative unfamiliarity with Hg test methods. Therefore, the final rule gives AETBs until January 1, 2009 to comply with ASTM D7036–04.

A number of other comments were received on the proposed AETB certification program. These are addressed in detail in the Response to Comments (RTC) document.

4. Linearity Requirements for Dual-Span Applications

Background

In May 1999, EPA revised the linearity check provisions in Part 75, Appendix A, section 6.2, to exempt SO_2 and NO_X span values of 30 ppm or less from performing linearity checks. Since the May 1999 revisions became effective, some have questioned whether the linearity exemption applies only to ongoing QA or whether it applies also to initial certification. Others have asked whether the exemption applies only to a particular measurement range or to all of the linearity check requirements for a monitoring system. In view of this, EPA proposed to revise Section 6.2 of Appendix A to make it clear that the 30 ppm linearity exemption: (1) Is range-specific; (2) covers both initial certification and ongoing QA; (3) does not remove the requirement to perform linearity checks of the high range (if > 30 ppm) for dual span applications; and (4) does not take away the linearity check requirements for the diluent monitor component of a NO_X-diluent monitoring system.

Summary of Rule Changes

The proposed amendments to Section 6.2 of Appendix A have been finalized, without substantive change. At the request of one commenter, the final rule clarifies that the low-span linearity exemption applies to recertification as well as to initial certification and ongoing QA.

5. Dual Span Applications-Data Validation

Background

EPA proposed to clarify the relationship between the quality-assured (QA) status of the low and high ranges of a gas monitor in a dual-span application. Sections 2.1.1.5(b) and 2.1.2.5(b) of Appendix A have provided instructions for reporting SO_2 and NO_X concentration data when the full-scale range of the monitor is exceeded. For single-range applications, reporting a value of 200 percent of the range has been required when a full-scale exceedance occurs. For dual range applications, if the low range is exceeded, no special reporting has been necessary, provided that the high range is ''available and not out-of-control or out-of-service for any reason''. However, if the high range is ''not able to provide quality-assured data'' during the low-range exceedance, then sources have been required to report the maximum potential concentration (MPC).

Believing that the two phrases used to describe the QA status of the high range during low-scale exceedances, *i.e.*, ''available and not out-of-control or out-of-service for any reason'' and ''not able to provide quality assured data'' to be too general, the Agency proposed to revise these rule texts by defining the QA status of the high range in terms of its most recent calibration error and linearity checks. Provided that both of these QA tests are still ''active'', *i.e.*, their windows of data validation have not expired, the high range would be considered in-control and able to provide quality-assured data. However if either of the tests has expired, data recorded on the high range would be considered invalid until the expired test was repeated and passed. The MPC would be reported until the expired high-range test is redone or until the data return to the low scale. Thus, the proposed revisions would clarify that when the low range is up-to-date on its QA tests but the high range is not, the QA status of each range is evaluated separately.

Summary of Rule Changes

No adverse comments were received. These provisions have been finalized, as proposed.

6. Cycle Time Test-Stability Criteria

Background

The cycle time test described in Section 6.4 of Appendix A is required for the initial certification and recertification of gas monitoring systems, and occasionally as a diagnostic test. The test is designed to determine how long it takes for a monitor to respond to step changes in gas concentration. Two calibration gases (zero- and high-level) are used for the test, which has both an upscale and a downscale component.

Section 6.4 has specified criteria for determining when a stable gas concentration reading has been obtained. The reading is considered stable if it changes by less than 2.0 percent of the span value for 2 minutes or less than 6.0 percent from the average concentration over 6 minutes. These criteria are reasonable when the source effluent concentrations are moderate or high. However, when concentrations are very low, the criteria can become overly stringent and difficult to meet. In view of this, the Agency proposed to add alternative stability criteria to Section 6.4 of Appendix A. By the alternative criteria, an SO_2 or NO_X reading would be considered stable if it changed by no more than 0.5 ppm for 2 minutes or, for a diluent monitor, if it changed by no more than 0.2% CO_2 or O_2 for 2 minutes.

Summary of Rule Changes

Substantive changes have been made to the cycle time test procedure, in response to comments received. The sequence of the test has been reversed, *i.e.*, it now begins with a stable reading of stack emissions and ends with a stable reading of calibration gas concentration (see section 2.6 of the Response to Comments document for further discussion). Commenters were generally supportive of the proposed alternative stability criteria, and these have been incorporated into the final rule. One commenter noted the absence of corresponding alternative stability criteria for Hg monitors. To correct this apparent oversight, the final rule includes an alternative specification of 0.5 μg/m³ for Hg CEMS. The same commenter also expressed concerns about temporal variations in stack gas concentration (particularly for Hg) that can make it difficult to meet the stability criteria, and recommended that the order of the cycle time test be reversed, *i.e.*, begin the test by measuring stack gas emissions and then inject the calibration gas. EPA agrees with this comment and has revised the cycle time test procedure and Figure 6 in Appendix A accordingly. EPA believes this change in the test procedure (which is closer to the way in which the test was originally presented in the January 1993 rule) gives a more accurate indication of the monitor's true response time and will help to prevent ''false positive'' test failures.

EPA has also revised the reporting requirement (in Appendix A § 6.4) for cycle time tests of dual range monitors in light of the transition to the revised XML format. The change requires that cycle time for both ranges of a component be reported separately (consistent with the reporting of other component level tests for CEMS), rather than only reporting the results from the range with the longer cycle time. This change is consistent with the proposed changes that required reporting of certain test at the component level rather than at a system/component level, which overall reduces redundant reporting of test data from shared components. No adverse comments were received on those similar proposed changes. This revision was necessary for consistency with those other proposed changes which EPA is finalizing.

7. System Integrity and Linearity Checks of Hg CEMS

Background

The required certification tests for a Hg CEMS include a 3-level system integrity check, using a NIST-traceable source of oxidized Hg and a 3-level linearity check, using elemental Hg standards. The performance specification for the system integrity check, which is found in paragraph (3)(iii) of Appendix A, Section 3.2, has been that the system measurement error must not exceed 5.0 percent of the span value at any of the three calibration gas levels. However no explanation of how to calculate the measurement error has been provided. EPA proposed to restructure paragraph (3) of Section 3.2, to add the necessary mathematical procedure.

Believing that the performance specification for the linearity check (which is done with elemental Hg) should be at least as stringent as the performance for the system integrity check (which is done with oxidized Hg), the Agency also proposed to make the linearity and system integrity check specifications for Hg monitors the same, *i.e.*, 5.0 percent of the span value, with an alternative specification to 0.6 μg/m³ absolute difference between the reference gas value and the monitor response.

Summary of Rule Changes

In the final rule, the performance specifications for the linearity checks and system integrity checks of Hg monitors have been made the same, but the proposed 5.0 percent of span criterion (with an alternative specification of 0.6 μg/m³) has not been adopted. The commenters did not take issue with the proposal to equalize the performance specifications for the two QA tests, but several commenters objected to the proposed values of the specifications, citing a lack of supporting data to demonstrate that the specifications are achievable. Two commenters favored setting both specifications at the existing values for the linearity check, *i.e.*, 10.0 percent of the reference gas value, with an alternative specification of 1.0 μg/m³.

In response to these comments, EPA analyzed data from two recent field studies in which elemental and oxidized Hg calibration gases were injected into commercially-available Hg CEMS, at different concentration levels (low, mid, high). Based on the results of the data analysis, the Agency has concluded that equalizing the performance specifications for linearity checks and system integrity checks of Hg monitors at 10.0 percent of the reference gas value, with an alternate specification of 0.8 μg/m³ absolute difference is appropriate, and the final rule incorporates these specifications.

A total of 97 data points from the two field studies were analyzed. Data recorded during known periods of probe malfunction and excessive analyzer drift were excluded from the analysis. Eighteen of the 97 data points analyzed were elemental Hg injections, and the rest were oxidized Hg injections. Each gas injection was evaluated on a pass/fail basis against six candidate sets of performance specifications. These were: (1) The proposed performance specifications, *i.e.*, 5.0 percent of span, with an alternative specification of 0.6 μg/m³; (2) the existing linearity specifications, *i.e.*, 10.0 percent of the reference gas value, with alternative specification of 1.0 μ/m³; (3) the existing system integrity specification, *i.e.*, 5.0 percent of span, with no alternative specification; (4) 5.0 percent of span, with an alternative specification of 0.8 μg/m³ ; (5) 5.0 percent of span, with an alternative specification of 1.0 μg/m³; and (6) 10.0 percent of the reference gas value, with alternative specification of 0.8 μg/m³. For each set of performance specifications, the pass rate of the 97 gas

injections was determined. The two highest pass rates (96.9% and 95.9%) were attained with sets (2) and (5), respectively, which have the widest alternative specification of 1.0 μg/m³. Similarly high pass rates (93.8% and 94.8%) were also attained with sets (4) and (6), both of which have an alternative specification of 0.8 μg/m³. The lowest pass rates (85.5% and 75.3%) were attained with sets (1) and (3), the proposed performance specifications and the existing system integrity check specification.

From these results, EPA concludes, on the one hand, that both the proposed performance specifications (set 1) and existing system integrity check specifications (set 3) may be too stringent. On the other hand, very high pass rates were achieved with the four sets having the wider alternate specifications of 1.0 μg/m³ and 0.8 μg/m³, *i.e.*, sets (2), (5), (4), and (6). For these four sets, it seems to make little or no difference whether the main specification is 5.0 percent of span or 10.0 percent of the reference gas value. In view of these considerations, EPA has selected the main specification for the system integrity and linearity checks to be 10.0 percent of the reference gas value, and the alternative specification to be the more stringent value of 0.8 μg/m³. These values have been incorporated into paragraph (3) of Section 3.2 in Appendix A.

8. Correction of Hg Calibration Gas Concentrations for Moisture

Background

When calibration error tests and linearity checks of SO_2, NO_X, and diluent gas monitors are performed, EPA protocol gases are used. The protocol gases are essentially moisture-free. However, when mercury monitors are calibrated, moisture is sometimes added to the calibration gas. This creates a potential source of error in the calculations. In view of this, EPA proposed to revise the calibration error procedures in section 6.3.1 of Appendix A, to require that when moisture is added to the Hg calibration gas, the moisture content of the gas must be accounted for. The proposed revisions would also require the calibration gas concentration to be converted to a dry basis for purposes of performing the calibration error calculations.

The Agency also proposed to add parallel language to Section 6.2 of Appendix A, in a new paragraph ''(h)'', to address this issue for the linearity checks and system integrity checks of Hg monitors.

Summary of Rule Changes

No comments were received on the proposal. Therefore, the provisions have been finalized, but there is one notable change. The proposed rule inappropriately limited the requirement to account for added moisture in the calibration gas to dry-basis Hg CEMS. In the final rule text, this restriction has been removed. This is simply a technical correction of a misstatement in the proposal.

9. Correction of Cross-References

Background

EPA proposed to correct a number of cross-references in Appendix A, Sections 6.2(g), 6.5.6(b)(3) and 6.5.6.3. Regarding the system integrity checks of Hg monitors, Section 6.2(g) of Appendix A incorrectly only referred to Section 2.6 of Appendix B, which only describes weekly, single-level system integrity checks. The proposed revisions would also refer to Sections 2.1.1 and 2.2.1 of Appendix B, which describe the 3-level system integrity checks. Finally, corrections to sections 6.5.6(b)(3) and 6.5.6.3 of Appendix A were proposed, changing references to Section 3.2 of Performance Specification No. 2 (PS2) to Section 8.1.3, of PS2.

Summary of Rule Changes

No adverse comments were received. These corrections have been finalized, as proposed.

I. Appendix B

1. 3-Load Flow RATA Frequency and RATA Grace Period

Background

On May 26, 1999, EPA revised Appendix B of Part 75, to reduce the required frequency of 3-load flow RATAs from annually to ''at least once every 5 consecutive calendar years''. As written, this rule provision actually allows more than five years (20 calendar quarters) to elapse between 3-load flow RATAs. For instance, if successive 3-load flow RATAs are performed in the 1st quarter of 2002 and in the 4th quarter of 2007, this satisfies the ''once every 5 consecutive calendar years'' requirement, but there would be 23 calendar quarters between the two tests.

In light of this, EPA proposed to revise Section 2.3.1.3(c)(4) of Appendix B, to require 3-load flow RATAs to be done at least once every 20 calendar quarters. This is consistent with both the other 5-year testing requirements in Part 75 (i.e., for Appendix E and LME units) and the maximum allowable interval between successive accuracy tests of Appendix D fuel flowmeters.

EPA also proposed to revise the RATA grace period provisions in Section 2.3.3, by removing the method of determining the deadline for the next RATA after a grace period test from paragraph (c) of Section 2.3.3 and replacing it with a different method described in new paragraph (d).

Paragraph (d) proposed a change to the methodology for determining RATA deadlines, without changing the end result. The intent of paragraph (c) in Section 2.3.3 had always been for the source to return to its original RATA schedule following a grace period test, in order to prevent the grace period provisions from being abused. However, for infrequently operated units (e.g., many combustion turbines), the grace period sometimes spans across many calendar quarters, which effectively eliminates the possibility of establishing a meaningful relationship between the original RATA due date and the deadline for the next test.

In view of these considerations, EPA proposed a simpler methodology for determining RATA deadlines that will work for both base load units and combustion turbines that seldom operate. The deadline for the next RATA following a grace period test would be two QA operating quarters after the quarter of the test, if the RATA results trigger a semiannual test frequency, and three QA operating quarters after the quarter of the test if the RATA qualifies for an annual test frequency. As proposed, there was one exception to these rules. Regardless of the number of QA operating quarters that have elapsed following the grace period test, the maximum allowable interval between a grace period RATA and the next RATA would be eight calendar quarters. This is consistent with Section 2.3.1.1(a) of Appendix B.

Finally, EPA proposed to amend paragraph (c) of Section 2.3.3, to state that when a RATA is performed after the expiration of a grace period, the ''clock'' is reset, and the deadline for the next RATA is determined in the usual manner, *i.e.*, the next test would be due within two QA operating quarters (for semiannual frequency) or four QA operating quarters (for annual frequency), not to exceed eight calendar quarters.

Summary of Rule Changes

Commenters were supportive of the proposed amendments to the RATA grace period provisions, and no comments were received on the proposal to determine 3-load flow RATA deadlines on a calendar quarter basis. Therefore, these provisions have been finalized, as proposed.

2. RATA Requirement for Shared Components

Background

EPA proposed to amend paragraph (g) in section 2.3.2 of Appendix B, to specify the consequences of a failed RATA, in the case where a particular NO_X pollutant concentration monitor is a component of both a NO_X concentration monitoring system and a NO_X-diluent monitoring system. In such cases, the Agency proposed that if the NO_X concentration system RATA is failed, both the NO_X concentration monitoring system and the associated NO_X-diluent monitoring system would be considered out-of-control, and successful RATAs of both monitoring systems would be required to get them back in-control.

Summary of Rule Changes

No adverse comments were received. This amendment has been finalized, as proposed.

3. AETB Requirements

Background

EPA proposed to amend Appendix B by adding a new Section, 1.1.4, to require that an Air Emissions Testing Body (AETB) that performs emission testing or RATAs for on-going quality-assurance under Part 75 must conform to ASTM D7036–04.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

4. Calibration Error Tests and Linearity Checks-Dual Range Applications

Background

EPA proposed to revise Sections 2.1.1, 2.1.1.2, 2.1.5.1 and 2.2.3(e) of Appendix B, to clarify the data validation requirements for daily calibration error tests and linearity checks of gas monitors when two span values and two measurement ranges are required for a particular parameter (*e.g.*, SO_2 or NO_X).

The proposed revisions to Section 2.1.1 of Appendix B would require that ''sufficient'' calibration error tests be performed on the low and high monitor ranges to validate the data recorded on each range, in accordance with Section 2.1.5 of Appendix B. EPA also proposed to add a new paragraph, (3), to Section 2.1.5.1 of Appendix B, to clarify how the QA status of the low and high ranges is determined when: (a) a calibration error test on one of the ranges is failed; or (b) the most recent calibration error test of one of the ranges has expired. Under proposed paragraph (3), when separate analyzers are used for the two ranges, a failed or expired calibration error test on one of the ranges would not affect the QA status of the other range. For a dual-range analyzer (*i.e.*, a single analyzer with two scales), a failed calibration error test on either range would result in an out-of-control period, and data from the monitor would remain invalid until corrective actions are taken, followed by successful ''hands-off'' calibrations of both ranges. However, if the most recent calibration error test on one range of a dual-range analyzer was successful, but its data validation window expires, this would have no effect on the QA status of the other range.

Further, the Agency proposed to amend Section 2.2.3(e) of Appendix B to make it clear that ''hands-off'' linearity checks of both ranges of a dual-range analyzer are required whenever a linearity check on either range fails or is aborted (unless, of course, a particular range is exempted from linearity checks under Section 6.2 of Appendix A).

Summary of Rule Changes

These provisions have been finalized, as proposed. Two commenters did not understand why failure of a calibration error test or a linearity check on one scale of a dual-range analyzer should invalidate data on both ranges, and asked for EPA to more fully explain the technical basis for this requirement.

The requirement to perform calibration error tests or linearity checks on both scales of a dual-range analyzer to resolve an out-of-control period does not reflect a change in Agency policy. Rather, EPA's proposal intended to clarify the existing requirement that each range of a dual-range monitor must be known to be in-control in order to validate data from the monitor.

The final rule allows data to be considered valid from a particular measurement range that has passed a calibration error check when the calibration error test for the other measurement range has expired. In such instances, since there is no indication that the monitor is not functioning properly, but there is evidence that the measurement range being used is properly calibrated, EPA is allowing that range to be considered quality assured. However, whenever a monitor fails any required daily, quarterly, semi-annual or annual quality assurance test, regardless of range, EPA maintains that data from that monitor must be considered invalid until the required quality assurance tests are passed. A failed test on either range of a dual range monitor indicates a problem with the monitor's ability to accurately measure emissions. While it is possible that in some instances, the problem causing the failure of a test on one range does not affect the accuracy of the monitor's measurements on the other range, it is far from certain. Therefore, the Agency's firm position is that whenever a calibration error test or linearity check is failed on either measurement scale of a dual-range analyzer, it is necessary to calibrate both ranges following corrective actions (which usually involve adjustments to the monitor), to verify that the monitor is back in-control and is able to generate quality-assured data on both ranges.

5. Off-Line Calibration Error Tests

Background

Section 2.1.1.2 of Appendix B allows the owner or operator to make limited use of off-line calibration error tests to validate data if an off-line calibration demonstration test is performed and passed. If the off-line calibration error demonstration is successful, then off-line calibrations may be used to validate up to 26 unit operating hours of data before an on-line calibration error test is required.

The off-line calibration provisions in Appendix B have not been well-understood by many affected sources. Through the years, EPA has received numerous requests for a more detailed explanation and/or examples of how to apply these rule provisions. In view of this, the Agency proposed to revise Sections 2.1.1.2 and 2.1.5.1 of Appendix B to clarify the data validation rules for off-line calibration error tests.

EPA proposed to revise paragraph (2) in Section 2.1.1.2 to state that sources may make limited use of off-line calibrations if the off-line calibration demonstration has been performed and passed. The proposed changes to paragraph (2) of Section 2.1.5.1 would explain what ''limited use'' of off-line calibrations means. Off-line calibrations could be used to validate up to 26 consecutive unit operating hours of data before an on-line test is required. Each individual off-line calibration would be valid only for 26 clock hours, and if the sequence of consecutive operating hours validated by off-line calibrations is broken before reaching the 26th consecutive unit operating hour, data from the monitor would become invalid until an on-line calibration is performed and passed.

Summary of Rule Changes

Numerous commenters objected to the proposed revisions to Section 2.1.5.1 of Appendix B. The commenters found the proposed rule language to be confusing

rather than clarifying, and several of them asserted that EPA appeared to be placing new restrictions on the use of off-line calibration error tests.

After careful consideration of these comments, EPA agrees that the proposed rule language, particularly the term ''sequence of consecutive unit operating hours'' can be misinterpreted. However, the Agency's intent was (and is) simply to clarify the existing procedures for using off-line calibrations to validate CEMS data. That is, a source desiring to use the off-line calibration provisions in paragraph (2) of Appendix B, section 2.1.5.1 must first pass the off-line calibration demonstration described in section 2.1.1.2. After successfully completing this demonstration, off-line calibrations may be used on a limited basis for data validation. In particular, off-line calibrations may be used to validate data for up to 26 consecutive unit operating hours following a passed on-line calibration error test.

The term ''consecutive unit operating hours'' does not mean consecutive clock hours. For example, two consecutive unit operating hours could be separated by several hours, days, weeks, etc., due to a unit outage. Each off-line calibration error test has the same prospective, 26 clock hour window of data validation as an on-line calibration error test.

Therefore, for a source that has passed the off-line calibration demonstration, EPA considers the data for a particular operating hour to be valid if there is: (1) A passed on-line calibration within the 26 *unit operating* hours preceding that operating hour; and (2) a passed off-line calibration within the 26 *clock* hours immediately preceding that operating hour. The Agency has revised the proposed rule language to clarify these requirements. For each hour of unit operation, these criteria will be used to evaluate each monitoring system's control status with respect to daily calibrations.

6. Weekly System Integrity Check—Data Validation

Background

For a Hg CEMS that is equipped with a converter and that uses elemental Hg for daily calibrations, Section 2.6 of Part 75, Appendix B requires a weekly system integrity check, using a NIST-traceable source of oxidized Hg. This ''weekly'' test is required once every 168 unit operating hours. However, due to an apparent oversight, Section 2.6 did not explain the consequences of either failing the test or failing to perform the test on schedule. In view of this, EPA proposed to add the following data validation rules for the weekly system integrity check to Section 2.6 of Appendix B: (a) If the test fails, it would trigger an out-of-control period until a subsequent system integrity check is passed; and (b) if the test is not performed within 168 unit operating hours of the previous successful system integrity check, data from the CEMS would become invalid, starting with the 169th unit operating hour and continuing until a system integrity check is passed.

The Agency also proposed to correct a typographical error in Section 2.6 of Appendix B. The performance specification for the weekly system integrity check was incorrectly referenced as Section 3.2 (c)(3) of Appendix A. The correct citation is Appendix A, Section 3.2, paragraph (3)(iii).

Summary of Rule Changes

The revision has been finalized as proposed. Several commenters objected to the proposed data validation rules for weekly system integrity checks of Hg CEMS. Commenters expressed concern that the specified test frequency, i.e., once every 168 unit operating hours, will cause scheduling difficulties, due to the limited availability of qualified technicians and other factors. The commenters requested that EPA provide a grace period of 72 to 96 hours for this QA test, to minimize the possibility of data loss.

EPA does not agree with the commenters' assertions that the 168 operating hour requirement will be difficult to implement and that a grace period should be added. The number of operating hours since the last weekly system integrity check can (and should) be tracked by the data acquisition and handling system (DAHS). An alarm or prompt could be activated when the deadline for the next test is near (e.g., when 120 or 144 operating hours have elapsed since the last test).

EPA favors basing the interval between successive tests on operating hours rather than clock hours in a week, primarily for reasons of simplicity. The Agency acknowledges that this is distinctly different from the way in which the deadlines for RATAs and linearity checks are determined. For a RATA or linearity check, the deadline is always at the end of a calendar quarter. Grace periods are provided for these tests because the deadlines can pass while the unit is either off-line or experiencing operational abnormalities that prevent the monitors from being tested on time. Also, a limited number of RATA deadline extensions and linearity check exemptions are provided for ''non-QA operating quarters'', i.e., calendar quarters in which the unit operates for < 168 hours.

However, the required frequency for the system integrity checks of a Hg CEMS is weekly, not quarterly. This is the only weekly QA test required by Part 75. Therefore, the existing ''QA operating quarter'' model and grace period scheme cannot be directly applied to the system integrity check. A new concept, perhaps a ''QA operating week'' would have to be introduced and an appropriate grace period determined. EPA considered this approach and decided against it, believing that it would unnecessarily complicate the process of QA status tracking for Hg CEMS.

The Agency believes that if the DAHS is programmed to track the number of unit operating hours since the last system integrity check and if an alert is provided to let plant personnel know when the test deadline is approaching, there will seldom, if ever be a missed test. Furthermore, the Agency believes that as experience is gained with Hg monitors, it may be possible to automate the weekly system integrity check so that during the 168th hour of operation since the last system integrity check, the check is automatically initiated by the DAHS computer system or other appropriate programmable logic controller (PLC) systems. Such automation would further reduce the probability of a missed test.

7. Correction of Hg Units of Measure—Figure 2

Background

EPA proposed to correct a minor error in the units of measure for Hg concentration in Figure 2 of Appendix B, changing the units of micrograms per dry standard cubic meter (μg/dscm) to micrograms per standard cubic meter (μg/scm). This change was proposed because not all Hg monitoring systems measure Hg concentration on a dry basis.

Summary of Rule Changes

No adverse comments were received. The proposed correction to Figure 2 has been made.

J. Appendix D

1. Update of Incorporation by Reference

Background

As previously noted, EPA proposed to update the list of test methods, sampling and analysis procedures, and other items that are incorporated by reference in § 75.6. As such, the proposed rule

included corresponding updates to the references in Appendix D.

EPA also proposed to add to Section 2.1.5.1 of Appendix D, the American Petroleum Institute's (API) Manual of Petroleum Measurement Standards Chapter 22—Testing Protocol: Section 2—Differential Pressure Flow Measurement Devices (First Edition, August 2005) as a new standard procedure for verifying flowmeter accuracy.

Summary of Rule Changes

These provisions have been finalized, as proposed. Note that in response to a comment, EPA has also incorporated by reference ASTM D5453–06, ''Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence'' [1], and has added ASTM D5453–06 to the list of acceptable oil sampling methods in Section 2.2.5 of Appendix D (see section 2.7 of the Response to Comments document for further discussion). In addition, the equation for Hourly SO_2 Mass Emissions from the Combustion of all Fuels in Appendix D, section 3.5.1 has been revised to be consistent with the new XLM format. This change is considered to be insignificant and was made to be consistent with the proposed changes to harmonize the units of measure for reporting hourly mass emissions.

2. Pipeline Natural Gas—Method of Qualification and Monthly GCV Values

Background

For a unit which combusts a fuel that meets the definition of ''pipeline natural gas'' (PNG) in § 72.2, Section 2.3.1.1 of Appendix D allows the owner or operator to estimate the unit's SO_2 mass emissions using a default SO_2 emission rate of 0.0006 lb/mmBtu. To qualify to use this SO_2 emission rate, the owner or operator must document that the natural gas has a total sulfur content of 0.5 grains per 100 standard cubic foot or less. Section 2.3.1.4 describes three ways to initially demonstrate that the gas meets this total sulfur requirement: (1) Based on the gas quality characteristics specified in a purchase contract, tariff sheet, or pipeline transportation contract; or (2) based on historical fuel sampling data from the previous 12 months; or (3) based on at least one representative sample of the gas, if the requirements of (1) or (2) cannot be met. When fuel sampling data are used to qualify, the rule has required that each individual sample result must meet the total sulfur limit. Once a fuel has qualified as pipeline natural gas, Section 2.3.1.4(e) of Appendix D requires annual sampling of the total sulfur content to demonstrate that the fuel still meets the definition of PNG. At least one sample per year must be taken and if multiple samples are taken, the rule has required each one to meet the 0.5 gr/100 scf total sulfur limit.

Many suppliers of natural gas regularly sample the total sulfur content of the gas (in many cases, daily) and provide that data to their customers upon request. Sources desiring to use this data to meet the initial or ongoing total sulfur sampling requirements of Appendix D have asked whether the gas would be disqualified from using the 0.0006 lb/mmBtu SO_2 emission rate if the total sulfur content of one of these daily samples exceeded 0.5 gr/100 scf. EPA has been handling these requests individually, on a case-by-case basis. However, the Agency believes it will be more efficient to address the issue through rulemaking. In view of this, amendments to Sections 2.3.1.4(a)(2) and (e) of Appendix D were proposed.

For the initial documentation that the gas meets the 0.5 gr/100 scf total sulfur limit, the proposed revisions to Section 2.3.1.4(a)(2) would allow sources with at least 100 total sulfur samples from the previous 12 months to reduce the data to monthly averages. Then, if all monthly averages meet the 0.5 gr/100 scf limit, the fuel would qualify as pipeline natural gas, and the source could use the 0.0006 lb/mmBtu default SO_2 emission rate. Alternatively, if at least 98 percent of the 100 (or more) samples from the previous 12 months have a total sulfur content of 0.5 gr/100 scf or less, the fuel would qualify as pipeline natural gas.

The proposed revisions to Section 2.3.1.4(e) would allow this same calculation methodology to be used for the annual total sulfur sampling requirement. That is, each year, if the results of at least 100 total sulfur samples from the past 12 months are obtained, the data could either be reduced to monthly averages, or the percentage of the samples that meet the 0.5 gr/100 scf limit could be determined.

EPA also proposed to clarify the gross calorific value (GCV) sampling requirements for pipeline natural gas in Section 2.3.4.1 of Appendix D. The current rule requires monthly GCV sampling for PNG. However, Section 2.3.4.1 refers only to the ''monthly sample'' (singular), whereas affected sources may collect and analyze multiple GCV samples each month, or may receive the results of multiple GCV samples from the fuel supplier each month. In view of this, the Agency proposed to revise Section 2.3.4.1 to require that the monthly average GCV value be used for Part 75 reporting, for any month in which multiple samples are taken and analyzed. To implement this provision in the case where the owner or operator has elected to use the actual monthly GCV value in the emission calculations, revisions to Section 2.3.7(c) of Appendix D were proposed, requiring the monthly average GCV value to be applied starting from the latest date of any of the individual GCV samples used to calculate the monthly average. In the case where an assumed GCV value is used in the calculations (i.e., either a contract value or the highest monthly average from the previous year), the assumed value would continue to be used unless superseded by a higher monthly average GCV value.

Summary of Rule Changes

The provisions pertaining to documentation that a particular gaseous fuel qualifies as pipeline natural gas have been finalized, with only minor editorial changes. Regarding the proposed requirement to average the results of all GCV samples of natural gas taken in each calendar month, one commenter asked whether the monthly average would be used to back-calculate the heat input values for each day in that month.

The proposed revisions to Section 2.3.7(c) of Appendix D specified that when the option to use the actual monthly GCV in the calculations is selected and multiple samples are taken, each monthly average GCV would be applied prospectively, starting on the date of the last sample taken during the month. However, in light of the commenter's question, EPA has reconsidered this approach. The final rule requires instead that each monthly GCV value be applied to every day in that month. The Agency believes that this approach provides a more representative estimate of the unit's true monthly heat input.

Note that the text of paragraph (b)(2) in section 2.3.7 has also been modified to address the new alternative methodology for making annual assessments of the sulfur content of natural gas.

3. Requirement to Split Oil Samples

Background

For affected units that combust fuel oil and use the Appendix D

[1] ASTM D5453–05 is no longer available. EPA is thus adding ASTM D5453–06, the version currently available. EPA considers this a minor ministerial correction.

methodology to quantify SO_2 mass emissions and/or unit heat input, Section 2.2 of Appendix D requires the owner or operator to perform periodic sampling of the sulfur content, gross calorific value and density of the oil (as applicable). Section 2.2.5 of Appendix D requires each oil sample to be split and a portion (at least 200 cc) of it to be maintained for at least 90 days after the end of the allowance accounting period.

The requirement to split and maintain a portion of each oil sample has been in Appendix D since it was first promulgated on January 11, 1993. At that time, on-site fuel oil sampling was required on every day that the unit combusted oil. Later, on May 17, 1995, an option to sample each shipment upon delivery was added for diesel fuel. Then, on May 26, 1999, the four basic oil sampling options in the current rule were put in place. However, the requirement to split and maintain a portion of each sample has remained unchanged through all of these rulemakings.

Believing that the requirement to split and maintain oil samples should only apply to samples that are taken at the affected facility, EPA proposed to revise Section 2.2.5 of Appendix D to limit this requirement to samples that are taken on-site. If this proposed amendment were finalized, sources electing to sample each fuel lot would no longer be required to split and maintain oil samples in cases where the samples are taken off-site, from the fuel supplier's storage container.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

K. Appendix E

1. AETB Requirements

Background

EPA proposed to revise Section 2.1 of Appendix E to require that any Air Emissions Testing Body (AETB) performing emission measurements to develop an Appendix E correlation curve or to derive a default emission rate for a LME unit, would have to conform to ASTM D7036–04.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

2. Reporting Data When the Correlation Curve Expires

Background

For oil and gas-fired peaking units using the Appendix E methodology to estimate NO_X emissions, the owner or operator is required, for each fuel type, to perform four-load emission testing for initial certification in order to develop a correlation curve of NO_X emission rate versus heat input rate. Each correlation curve is programmed into the data acquisition and handling system (DAHS), and retesting is required every five years (20 calendar quarters) to develop a new curve.

If the 20 calendar quarter test deadline passes without a retest having been performed, the previous correlation curve expires and is no longer valid. However, the appropriate missing data procedure to follow when a correlation curve expires has been conspicuously absent from Section 2.5 of Appendix E. To address this deficiency, EPA proposed to add a new Section, 2.5.2.4, to Appendix E, requiring the fuel-specific maximum potential NO_X emission rate (MER) to be reported, from the date and hour in which a baseline correlation curve expires until a new correlation curve is generated.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

L. Appendix F

1. NO_X Mass Calculations

Background

EPA proposed to revise the manner in which NO_X mass data are collected under the XML format that will be required in 2009 as part of EPA's effort to re-engineer the Agency's data collection systems. To achieve this, the hourly NO_X mass emission rate (lb/hr) would be reported instead of hourly NO_X mass emission (lb), when the source transitions from EDR reporting format to the XML format.

To effect this, Equations F–24, and F–27 in Appendix F of Part 75 would have to be modified and Equation F–26 removed. However, since the current EDR reporting format will continue to be supported through 2008, these equations must remain in the rule until the transition to XML is complete. Therefore, EPA proposed to revise Section 8 of Appendix F by adding Equations F–24a for the reporting of hourly NO_X mass emission rate (lb/hr) and Equation F–27a , for the calculation of cumulative NO_X mass emissions. In 2009, the use of Equations F–24a and F–27a would become mandatory for all sources and Equations F–24 and F–27 would no longer be applicable.

EPA also proposed to revise Section 8.2 of Appendix F, by splitting it into two subsections, 8.2.1 and 8.2.2. Section 8.2 had described a procedure for calculating the NO_X mass emission rate in lb/hr, when NO_X mass emissions are determined using a NO_X concentration monitoring system and a flow monitor. However, Section 8.2 simply cross-referenced other parts of the rule, rather than showing the actual equations used. To correct this, the Agency proposed to add Equation F–26a to subsection 8.2.1 and Equation F–26b to subsection 8.2.2, clearly showing how the NO_X mass emission rate is calculated on a wet and dry basis, and to renumber Equation F–26 in Section 8.3 as Equation F–26c. Proposed Equations F–26a and F–26b have been used since 2002 by sources in the NO_X Budget Program, and the equations have been represented in the EDR reporting instructions as Equations N–1 and N–2, respectively.

Summary of Rule Changes

No adverse comments were received. These provisions have been finalized, as proposed.

2. Use of the Diluent Cap

Background

EPA proposed to restrict the use of the diluent cap to NO_X emission rate determinations. The original purpose for allowing the diluent cap to be used was to keep calculated NO_X emission rates from approaching infinity during periods of unit startup and shutdown, when the diluent gas (CO_2 or O_2) concentration is close to the level in the ambient air. However, since 1999, Part 75 has allowed the diluent cap to be used for heat input rate calculations, CO_2 mass emission calculations, and calculation of hourly CO_2 concentration from measured O_2 concentrations, in addition to being used for NO_X emission rate. Sources have been allowed to use the cap value for some of these calculations and not others, which greatly complicates the data collection process. EPA has also found that using the diluent cap for other parameters besides NO_X emission rate always leads to over-reporting of these parameters, which is clearly contrary to the intended purpose of the diluent cap. Therefore, the Agency proposed to remove all of the references in Sections 4 and 5 of Appendix F that allow the diluent cap to be used for other parameters besides NO_X emission rate.

Summary of Rule Changes

No adverse comments were received. These provisions have been finalized, as proposed.

3. Negative Emission Values

Background

EPA proposed to provide special reporting instructions to account for situations where the equations prescribed by the rule yield negative values. First, when Equation 19–3 or 19–5 (from EPA Method 19 in 40 CFR Part 60, Appendix A) is used to calculate NO_X emission rate, modified forms of these equations, designated as Equations 19–3D and 19–5D, would be used whenever the diluent cap is applied. Second, for any hour where Equation F–14b results in a negative hourly average CO_2 value, EPA proposed to require 0.0% CO_2 to be reported as the average CO_2 value for that hour. Third, the Agency proposed to require a default heat input rate value of 1 mmBtu/hr to be reported for any hour in which Equation F–17 results in a negative hourly heat input rate. These changes would be accomplished by modifying Sections, 3.3.4, 4.4.1, and 5.2.3 of Appendix F.

Summary of Rule Changes

These provisions have been finalized, with one notable change. The final rule will require a default heat input rate value of 1 mmBtu/hr to be reported for any hour in which Equation F–17 results in a hourly heat input rate that is less than or equal to zero.

4. Calculation of Stack Gas Moisture Content

Background

EPA proposed to add Equation F–31 to a new Section 10 in Appendix F, to be used to calculate stack gas moisture values from wet and dry oxygen measurements, as described in Appendix A, Section 6.5.7(a). Sources have been using this equation for many years and it has been represented in the EDR reporting instructions as Equation M–1.

Summary of Rule Changes

No adverse comments were received. This provision has been finalized, as proposed.

5. Site-Specific F-Factors (Single Fuel)

Background

For units that use CEMS to measure the NO_X emission rate in lb/mmBtu and/or the unit heat input rate in mmBtu/hr, an equation from Appendix F of Part 75 or from Method 19 of 40 CFR Part 60 is required to convert the raw CEMS data into the proper units of measure. Each of these equations contains an F-factor, which represents either the total volume of flue gas or the volume of CO_2 generated per million Btu of heat input. The F-factor is fuel-specific.

Sections 3.3.5 and 3.3.6 of Appendix F allow the owner or operator to use either a default F-factor from Table 1 in Appendix F, or use Equation F–7a or F–7b in Appendix F to calculate a site-specific F-factor, based on the composition of the fuel. However, Appendix F has never specified how much fuel sampling data is required to develop a site-specific F-factor or how often the F-factor must be updated.

To address this issue, EPA proposed to revise the introductory text of Appendix F, Section 3.3.6 to require each site-specific F-factor to be based on a minimum of 9 samples of the fuel. Fuel samples taken during the 9 runs of an annual RATA would be acceptable for this purpose. Further, re-determination of the F-factor would be required at least annually, and the value from the most recent determination would be used in the emission calculations.

Summary of Rule Changes

No adverse comments were received. These provisions have been finalized, as proposed.

6. Prorated F-Factors

Background

For affected units that co-fire combinations of fossil fuels or fossil fuels and wood residue and that use CEMS to monitor the NO_X emission rate or unit heat input rate, Section 3.3.6.4 of Appendix F has required a prorated F-factor to be used in the emission calculations. The prorated F-factor is calculated using Equation F–8 in Appendix F. In applying Equation F–8, the F-factor for each type of fuel is weighted according to the fraction of the total heat input contributed by the fuel. However, Equation F–8 has never specified how the total unit heat input and the fraction of the heat input contributed by each fuel are determined. Data from the CEMS cannot be used for this purpose because the prorated F-factor must be known before the unit heat input rate can be calculated.

To correct this situation, EPA proposed to revise the definition of ''X_i'' (the fraction of the total heat input derived from each fuel) in the Equation F–8 nomenclature. The proposed revision would require sources to determine X_i from the best available information on the quantity of each fuel combusted and its GCV value over a specified time period. The value of X_i would be updated periodically, either hourly, daily, weekly, or monthly, and the prorated F-factor used in the emission calculations would be derived from the X_i values from the most recent update. The owner or operator would be required to document in the hard copy portion of the monitoring plan the method used to determine the X_i values.

Summary of Rule Changes

The revisions to Section 3.3.6.4 of Appendix F regarding the prorating of F-factors have been finalized, with only minor changes. However, several commenters requested that EPA consider allowing the use of the ''worst-case'' (i.e., highest) F-factor as an alternative to prorating, when combinations of fuels are co-fired. After careful consideration of these comments, EPA is persuaded by the commenters' arguments in favor of this option and has decided to incorporate this suggestion into the final rule (see section 2.4 of the Response to Comments document). New Section 3.3.6.5 of Appendix F allows sources that burn combinations of fuels listed in Table 1 of Appendix F to use the highest (''worst-case'') F-factor for any unit operating hour, in lieu of prorating the F-factor. Note that in view of the revisions to Section 3.3.6.4, Agency has deemed it necessary to modify the language in Section 3.3.6.3 of Appendix F. Administrative approval of the F-factor is no longer required when combinations of fossil fuels with wood or bark are combusted, since F-factors for these fuels are listed in Table 1. Rather, revised Section 3.3.6.3 requires Administrative approval of the F-factor only when a fuel not listed in Table 1 is co-fired with a fuel (or fuels) listed in the Table.

7. Default F-Factors

Background

In recent years, petroleum coke and tires have begun to be used as primary or secondary fuels by a number of affected sources. In view of this, EPA proposed to add default F-factors for petroleum coke and tire-derived fuels to Table 1 in Section 3.3.5 of Appendix F. The proposed values were 9,832 dscf/mmBtu for F_d and 1,853 scf CO_2/mmBtu for F_c for petroleum coke and 10,261 dscf/mmBtu for F_d and 1,803 scf CO_2/mmBtu for F_c for tire-derived fuels. The Agency also proposed F-factors of 9,819 dscf/mmBtu (for F_d) and 1,840 scf CO_2/mmBtu (for F_c) for sub-bituminous coal. All of the proposed F-factors were calculated using Equations F–7a and F–7b and representative composition and gross calorific value (GCV) data for each fuel.

Summary of Rule Changes

These provisions have been finalized, with minor editorial changes. One commenter recommended that the proposed F-factor values be rounded off to the nearest multiple of 10, to be consistent with the other values in Table 1. EPA agrees with this comment and has rounded off the F-factors accordingly.

8. Revisions to Equation F–23

Background

Consistent with the proposed changes to § 75.11(e), expanding the applicability of Equation F–23, EPA proposed to amend Section 7 of Appendix F (introductory text), and the Equation F–23 nomenclature.

Summary of Rule Changes

No adverse comments were received. These provisions have been finalized, as proposed.

M. Appendix G

Background

Consistent with the changes to other parts of the rule, EPA proposed to update the current ASTM standards listed in Sections 2.1.2, 2.2.1, and 2.2.2, of Appendix G, citing the newer versions.

Summary of Rule Changes

No adverse comments were received. These provisions have been finalized, as proposed.

N. Appendix K

Background

EPA proposed to addresses several issues regarding the use of sorbent trap monitoring systems for the measurement and reporting of Hg mass emissions. When this monitoring option is selected, paired sorbent traps are required to measure the effluent Hg concentration. If the two Hg concentrations measured by the paired traps meet the required relative deviation (RD) specification in Appendix K of Part 75, and if each trap individually meets certain other QA requirements of Appendix K, then the two Hg concentrations are averaged arithmetically and the average value is used to determine the Hg mass emissions in each hour of the data collection period. However, in cases where either or both of the traps fails to meet the acceptance criteria, § 75.15(h) and Table K–1 in Appendix K specify consequences of varying severity. In the months following promulgation of these rule provisions, EPA revisited them and concluded that some of the consequences were too lenient and others unnecessarily severe. The Agency therefore proposed to revise them to make them more consistent and equitable.

Whenever one of the paired traps is accidentally lost, damaged, or broken and cannot be analyzed, § 75.15(h) has allowed the owner or operator to use the remaining trap to determine the Hg concentration for the data collection period, provided that the remaining trap meets all of the QA requirements of Appendix K. But no adjustment of the data has been required to compensate for the loss of one of the samples. In view of this, EPA proposed to revise § 75.15(h) to require that the Hg concentration measured by the remaining valid trap be multiplied by a ''single trap adjustment factor'' (STAF) of 1.222. The STAF represents the maximum amount by which the Hg concentration from the lost, damaged or broken trap could have exceeded the concentration measured by the valid trap and still met the 10% RD specification.

The Agency also proposed to revise Table K–1 in Appendix K, to extend the use of the STAF to cases where one of the paired sorbent traps either: (a) fails a post-test leak check; (b) has excessive breakthrough in the second section; or (c) is unable to meet the required percent recovery of the third section elemental Hg spike. In all three of these cases, provided that the other trap meets all Appendix K requirements, rather than invalidating the sorbent trap system data for the entire collection period, the Hg concentration measured by the valid trap, multiplied by the STAF, could be used for Part 75 reporting.

Section 7.2.3 of Appendix K requires that for each hour of the data collection period, the ratio of the stack gas flow rate to the sample flow rate through each sorbent trap must be maintained within ±25 percent of the initial ratio established in the first hour of the data collection period. However, the rule has stated that when this criterion is not met, the appropriate consequences are to be determined on a ''case-by-case'' basis. EPA has reconsidered this approach and now believes that it allows for inconsistent application of the sorbent trap monitoring methodology. Therefore, the Agency proposed to revise Table K–1 to specify that a sample is invalidated if either: (a) More than 5 percent of the hourly ratios; or (b) more than 5 hourly ratios in the data collection period (whichever is less restrictive) fail to meet the ±25 percent acceptance criterion. Further, if only one of the paired traps is able to meet the specification, provided that it also meets the rest of the Appendix K QA criteria, the valid trap could be used for Part 75 reporting, if the STAF value of 1.222 is applied to the measured Hg concentration.

Appendix K has required data from a sorbent trap monitoring system to be invalidated whenever the relative deviation between the Hg concentrations measured by the paired traps is greater than 10 percent. EPA proposed to revise this requirement, to allow sources to report the higher of the two Hg concentrations measured by a pair of sorbent traps whenever the RD specification is not met, rather than invalidating the sorbent trap system data for the entire collection period. The Agency also proposed, for consistency with the proposed changes § 75.22(a), to revise Table K–1 to include an alternative relative deviation specification of 20 percent for paired sorbent traps, when low effluent concentrations of Hg (≤ 1 μg/m^3) are encountered.

EPA further proposed to add two new paragraphs, (k) and (l), to § 75.15. Proposed § 75.15(k) would have required that whenever the RATA of a sorbent trap system is performed, the sorbent traps used to collect the RATA run data must be the same size as the traps used for daily operation of the monitoring system. Likewise, the sorbent material must be the same type that is used for daily operation. Proposed § 75.15(l) would have required a diagnostic RATA of the sorbent trap system whenever either the size of the sorbent traps or the type of sorbent material was changed. Data from the modified sorbent trap system would not have been acceptable for Part 75 reporting until the RATA is passed, with one exception, i.e., data collected during a successful diagnostic RATA test period could be reported as quality-assured.

Finally, revisions to section 7.2.3 of Appendix K were proposed, requiring that the sample flow rate through a sorbent trap monitoring system must be zero when the unit is not operating. EPA believes this clarification is needed to prevent the system from sampling ambient air during periods when the combustion unit is off-line, which would artificially lower the Hg concentrations measured by the sorbent traps, resulting in under-reporting of Hg mass emissions.

Summary of Rule Changes

The commenters generally favored the proposal to add a 20 percent alternative relative deviation (RD) specification for sources with low Hg emissions (≤ 1.0

μg/m³). However, concerns were expressed that even a 20 percent RD specification might be difficult to meet when emissions are exceptionally low. For instance, following a flue gas desulfurization system, the Hg emission levels can be as low as 0.1 to 0.2 μg/m³. One commenter suggested that the allowable RD for low emitters should be either 20 percent or 0.03 μg/m³ absolute difference, whichever is less restrictive (see section 2.9.2 of the Response to Comments document). EPA agrees with this comment and has incorporated the 0.03 μg/m³ alternative RD specification into both Appendix K (for sorbent trap monitoring systems), and § 75.22 (for the Ontario Hydro Method and EPA Method 29).

The commenters were divided on the proposed single trap adjustment factor (STAF) provisions. Two commenters supported the proposed amendments and four others objected to them. Those objecting expressed concern that applying the proposed STAF value of 1.222 in cases where one trap meets all of the QA requirements is unnecessarily punitive. Several of the commenters recommended that the STAF value should be 1.111, which would be consistent with the averaging that is performed when the results of both traps are available and would appropriately weight the results of the valid trap (see section 4.3 of the Response to Comments document for further discussion). After careful consideration of the comments, EPA has decided to incorporate the commenters' suggestion regarding the value of the STAF. Therefore, the single-trap adjustment factor provisions have been finalized as proposed, except that the value of the STAF is 1.111.

Regarding proposed paragraphs (k) and (l) in § 75.15, EPA has reconsidered its position and has withdrawn the requirement for the sorbent traps used for RATA testing to be the same size as the traps used for daily operation of the monitoring system. Accordingly, the proposed requirement to perform a diagnostic RATA when the trap size is changed has also been withdrawn. The Agency is finalized paragraph (k) as part of a direct-final rulemaking on September 7, 2007 (72 FR 51494–51531). Paragraph (k) requires only that the type of sorbent material used for the RATAs be the same as the sorbent material used for daily operation. Today's rule finalizes paragraph (l) of § 75.15, to require a diagnostic RATA within 720 operating hours whenever a new type of sorbent material begins to be used in the traps (e.g., using brominated carbon instead of iodated carbon). Commenters on proposed paragraph (l) questioned why data collected by the modified sorbent trap system are considered invalid prior to the diagnostic RATA. The commenters requested that EPA revise paragraph (l) to allow data collected prior to the diagnostic RATA to be reported as valid if the RATA is passed. The commenters' suggestion is reasonable and has been incorporated into the final rule. A passed diagnostic RATA demonstrates that the change in sorbent material has not significantly affected the monitoring system's ability to accurately measure Hg emissions. Therefore, § 75.15(l) allows the data from the modified sorbent trap system to be considered conditionally valid according to § 75.20(b)(3), for up to 720 unit or stack operating hours after switching to a new type of sorbent material. If the diagnostic RATA is passed within the 720 operating hour window, the data recorded by the modified system prior to the RATA may be reported as quality-assured. If the RATA is failed, no data from the modified system may be reported as quality-assured until a subsequent RATA is passed. If the diagnostic RATA is not completed within the allotted 720 operating hour window but is passed on the first attempt, data from the modified system are considered to be invalid from the first hour after the expiration of the 720 operating hour window until the completion of the RATA.

No comments were received on the following proposed amendments: (1) The proposal to allow the higher Hg concentration to be reported when the RD criterion for the paired sorbent traps is not met; (2) the proposed acceptance criteria for the hourly ratios of stack gas flow rate to sample flow rate; and (3) the proposal to require the sample flow rate through a sorbent trap monitoring system to be zero when the affected unit is off-line. Therefore, these provisions have been finalized, as proposed.

O. Other Rule revisions

1. Particulate Matter Monitoring Systems

Background

EPA received a comment that was outside the scope of the proposed rule, requesting that units with installed particulate matter (PM) monitoring systems be exempted from the opacity monitoring requirements of § 75.14.

Summary of Rule Changes

Although the comment was outside the scope of this rulemaking and no response is required, EPA believes that it has merit in light of June 13, 2007 amendments to Subparts Da and Db of 40 CFR Part 60 (see: 72 FR p.32710). For certain affected units (some of which are also subject to Part 75), these rule revisions either require or allow a particulate matter (PM) monitoring system to be used in lieu of an opacity monitor (e.g., see §§ 60.49Da(t), and 60.48b(j)).

Summary of Rule Changes

Today's rule incorporates the commenter's recommendation, as new paragraph (e) in § 75.14. The Agency believes that this revision to Part 75 is non-controversial and is consistent with EPA's ongoing commitment to harmonization of the Part 60 and Part 75 continuous monitoring regulations.

2. Default Moisture Values for Hg Monitoring

Background

For dry-basis Hg CEMS and sorbent trap monitoring systems, the hourly Hg emissions data must be corrected for the stack gas moisture content. This requirement can be met by using one of the fuel-specific default moisture values specified in Part 75. Several places in § 75.80, § 75.81, and Appendix K state that for the purposes of Hg monitoring, a default moisture value from § 75.11(b) or § 75.12(b) may be used in lieu of installing a continuous moisture monitoring system. However, the reference to § 75.12(b) is incorrect. Only the default moisture values in § 75.11(b) are appropriate for Hg monitoring applications. Equation F–29, the only Hg mass emissions equation with a moisture correction term, is structurally similar to Equation F–2 for SO_2 mass emissions. The default moisture values in § 75.11(b) are the ones that apply to Equation F–2. Hence, they apply also to Equation F–29. The default moisture values in § 75.12(b) are used for NO_X emission rate calculations, and several of them are not applicable to Hg mass emissions monitoring.

Summary of Rule Changes

All references to the default moisture values in § 75.12(b) have been removed from § 75.80, § 75.81, and Appendix K.

3. Hg Stratification Testing

Background

To support the Clean Air Mercury Regulation (CAMR), which was published in 2005 (*see:* 70 FR 28606, May 18, 2005), EPA added Hg monitoring provisions to Part 75, among which were revisions to § 75.22(a) and to section 6.5.10 of Appendix A, specifying ASTM D6784–02, the ''Ontario Hydro Method'', as the appropriate reference method for

measuring Hg concentration. On August 22, 2006 EPA proposed to add Method 29 (which is similar to Ontario Hydro) to Part 75, as an alternative Hg reference method. Most recently, in a direct-final action on September 7, 2007. EPA published two more alternative reference methods (RMs) for measuring vapor phase Hg emissions, Method 30A (an instrumental method) and Method 30B (a sorbent-based method). Today's rule allows the use of Methods 29, 30A, and 30B as alternatives to the Ontario Hydro Method (see the revisions to § 75.22(a) and Section 6.5.10 of Appendix A). EPA anticipates that in 2008 and beyond, all four of the Hg reference methods in Part 75 will be used, to a greater or lesser extent, for the Hg emission testing required under §§ 75.81(c) and (d) and for RATAs of Hg monitoring systems.

For Hg emission tests, Methods 30A and 30B require 12 sampling points (located according to EPA Method 1) for each test run, unless the results of a Hg stratification test justify using fewer points. The Ontario Hydro Method and Method 29 each require a minimum of 12 sample points and do not include any stratification test provisions or alternative sampling point location criteria.

For the RATAs of Part 75 Hg monitoring systems, when Methods 30A and 30B are used, both methods defer to the RM point selection and location procedures described in Part 75, Appendix A, section 6.5.6 and Performance Specification 2 (PS2) in Appendix B of 40 CFR Part 60. This is the familiar sampling approach that allows the use of a ''short'' 3-point measurement line at locations where stratification is not expected, but requires the use of a 3-point ''long'' measurement line (which includes a point at the center of the stack) at locations where stratification is suspected (e.g., after a wet scrubber), unless the results of a stratification test justify using the 3-point short line (or perhaps a single sampling point). As an alternative, Part 75 allows the use of six Method 1 sampling points located along a diameter, at any test location (including those where stratification is suspected). This same RM sampling point location methodology applies to Hg RATAs in which the Ontario Hydro Method or Method 29 is used as the reference method.

However, when testing is performed downstream of a scrubber, measuring at the center of a large-diameter stack is extremely difficult logistically, and testing at 6 points along a diameter may not be possible for certain test platform and test port configurations. Therefore, historically, most testers have opted to perform stratification testing at scrubbed stacks to justify sampling along a 3-point short line (or at a single point), which greatly simplifies the test procedures, in that all measurements can be made at one test port, using a probe of reasonable length. Unfortunately, Part 75 does not have a stratification test procedure for Hg, and, as previously noted, neither the Ontario Hydro Method nor Method 29 has any stratification test provisions—but there is a Hg stratification test procedure in Method 30A.

Summary of Rule Changes

In view of these considerations, EPA has deemed it necessary to revise Section 6.5.6(c) of Appendix A, to cross-reference the Hg stratification test provisions in Sections 8.1.3 through 8.1.3.5 of Method 30A. Further, § 75.22(a)(7) has been revised to address RM sample point location and stratification testing when the Ontario Hydro Method or Method 29 is used for the Hg low mass emission testing required under §§ 75.81(c) and (d). For that particular application, revised § 75.22(a)(7) requires the sampling points to be located according to Section 8.1 of Method 30A and cross-references the stratification test provisions in sections 8.1.3 through 8.1.3.5 of Method 30A.

These amendments to Appendix A and § 75.22 provide a consistent approach to stratification testing and RM sampling point location for Hg emission testing and Hg monitoring system RATAs, irrespective of which Hg reference method is used for the testing.

II. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

This action is not a ''significant regulatory action'' under the terms of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under the EO.

B. Paperwork Reduction Act

The information collection requirements in the final rule have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2203.02. The information collection requirements are not enforceable until OMB approves them.

The information requirements are based on the revisions to the monitoring, recordkeeping, and reporting requirements in 40 CFR Part 75, which are mandatory for all sources subject to the Acid Rain Program under Title IV of the Clean Air Act and certain other emissions trading programs administered by EPA. All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR Part 2, subpart B. The preexisting Part 75 rule requirements amended in this final rule are covered by existing ICRs for the Acid Rain Program (EPA ICR number 1633.14; OMB control number 2060–0258), the NO_X SIP Call (EPA ICR number 1857.04; OMB number 2060–0445), and the Clean Air Interstate Rule (EPA ICR number 2152.02; OMB number 2060–0570). The separate ICR for the final rule revisions addresses the one-time costs necessary for sources to review the rule revisions and adapt their recordkeeping and reporting systems to the revised requirements. The EPA believes that the long term implications of the rule revisions will be to reduce the ongoing burdens and costs associated with Part 75 compliance, but those impacts will be addressed as EPA renews the individual program ICRs. The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the final rule) is estimated to be 124,976 labor hours per year at a total annual cost of $8,581,420. This estimate includes burdens for rule review, recordkeeping and reporting software upgrades, and software debugging activities, as well as the capital costs of upgrading recordkeeping and reporting software.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it

displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR Part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the SBA's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on small entities, the impact of concern is any significant adverse economic impact on small entities, since the primary purpose of the regulatory flexibility analysis is to identify and address regulatory alternatives ''which minimize any significant economic impact of the rule on small entities.'' 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden or otherwise has a positive economic effect on all of the small entities subject to the rule. These final rule revisions represent minor changes to existing monitoring requirements used in EPA emission trading programs and we expect these revisions to reduce the economic burden for affected entities in the long term.

Although there will be some small level of up front costs to reprogram existing electronic data reporting software used under this program, the long term effects of these revisions will be to allow continued efficient electronic data submittals that should act to relieve some of the long term reporting burdens for affected sources, which include some small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements. EPA has determined that this final rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments in the aggregate, or to the private sector in any 1 year, nor does this rule significantly or uniquely impact small governments, because it contains no requirements that impose new obligations upon them. Thus, this final rule is not subject to the requirements of sections 202 and 205 of the UMRA.

EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. The revisions primarily make certain changes EPA has determined are necessary as part of upgrading the data systems used to manage data submitted under the program and to streamline the methods for sources to report their information. The revisions also clarify certain issues that have been raised during ongoing implementation of the existing rule and update the information on various voluntary consensus standards incorporated by reference in the rule. Some States do have programs that rely on the monitoring provisions in 40 CFR Part 75, and States may incur some costs associated with reviewing the modifications to Part 75, but the rule revisions and the impact on the States are not significant.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that 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.'' This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. These rule revisions represent minor adjustments to existing regulations. The revisions primarily make certain changes EPA has determined are necessary as part of upgrading the data systems used to manage data submitted under the program and to streamline the methods for sources to report their information. The revisions also clarify certain issues that have been raised during ongoing implementation of the existing rule and update the information on various voluntary consensus standards incorporated by reference in the rule. Some States do have programs that rely on the monitoring provisions in 40 CFR Part 75, and States may incur some costs

associated with reviewing the modifications to Part 75, but the rule revisions and the impact on the States are not significant. Thus, Executive Order 13132 does not apply to this final rule.

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

Executive Order 13175, entitled ''Consultation and Coordination With Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This final rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes. Thus, Executive Order 13175 does not apply to this final rule.

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

Executive Order 13045: ''Protection of Children From Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This rule is not subject to Executive Order 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

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

This rule is not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law No. 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards. This rule includes updated information on a number of voluntary consensus standards previously included in 40 CFR Part 75, as well as the addition of certain other voluntary consensus standards.

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

Executive Order 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. This final rule does not affect or relax the control measures on sources impacted by emission trading programs that rely on monitoring under 40 CFR Part 75.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the Agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective on January 24, 2008 for good cause found as explained in this rule.

L. Petitions for Judicial Review

Under Clean Air Act section 307(b)(1), petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by March 24, 2008. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review, nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such a rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2) of the Administrative Procedures Act.)

M. Determination Under Section 307(d)

Pursuant to Clean Air Act section 307(d)(1)(U), the Administrator determines that this action is subject to the provisions of section 307(d). Section 307(d)(1)(U) provides that the provisions of section 307(d) apply to ''such other actions as the Administrator may determine.'' While the Administrator did not make this determination earlier, the Administrator believes that all of the procedural requirements, e.g., docketing, hearing and comment periods, of section 307(d) have been complied with during the course of this rulemaking.

List of Subjects in 40 CFR Parts 72 and 75

Environmental protection, Acid rain, Administrative practice and procedure, Air pollution control, Carbon dioxide, Continuous emission monitoring, Electric utilities, Incorporation by reference, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: December 19, 2007.

Stephen L. Johnson,

Administrator.

■ For the reasons set forth in the preamble, parts 72 and 75 of chapter I of title 40 of the Code of Federal Regulations are amended as follows:

PART 72—PERMITS REGULATION

■ 1. The authority citation for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

Subpart A—Acid Rain Program General Provisions

■ 2. Section 72.2 is amended as follows:

■ a. Revising the definition of ''Capacity factor'';

■ b. In the definition of ''Diluent cap'', by removing the words '', CO_2 mass emission rate, or heat input rate,'' after the words ''NO_X emission rate'';

■ c. In the definition of ''EPA protocol gas'', by adding a new sentence to the end of the definition;

■ d. Revising the definition of ''Excepted monitoring system'';

■ e. Adding the new definitions in alphabetical order for ''Air Emission Testing Body (AETB)'', ''EPA Protocol Gas Verification Program'', ''Long-term cold storage'', ''NIST traceable elemental Hg standards'', ''NIST traceable source of oxidized Hg'', ''Qualified Individual'', and ''Specialty gas producer''; and

■ f. Removing the definition for ''Research gas material (RGM)''

The revisions and additions read as follows:

§ 72.2 Definitions.

* * * * *

Air Emission Testing Body (AETB) means a company or other entity that conducts Air Emissions Testing as described in ASTM D7036–04 (incorporated by reference under § 75.6 of this part).

* * * * *

Capacity factor means either:

(1) The ratio of a unit's actual annual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) times 8760 hours; or

(2) The ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours.

* * * * *

EPA protocol gas * * * On and after January 1, 2009, vendors advertising certification with the EPA Traceability Protocol *or* distributing gases as ''EPA Protocol Gas'' must participate in the EPA Protocol Gas Verification Program. Non-participating vendors may not use ''EPA'' in any form of advertising for these products, unless approved by the Administrator.

EPA Protocol Gas Verification Program means the EPA Protocol Gas audit program described in Section 2.1.10 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121 (EPA Protocol Procedure) or such revised procedure as approved by the Administrator.

* * * * *

Excepted monitoring system means a monitoring system that follows the procedures and requirements of § 75.15 of this chapter, § 75.19 of this chapter, § 75.81(b) of this chapter or of appendix D, or E to part 75 for approved exceptions to the use of continuous emission monitoring systems.

* * * * *

Long-term cold storage means the complete shutdown of a unit intended to last for an extended period of time (at least two calendar years) where notice for long-term cold storage is provided under § 75.61(a)(7).

* * * * *

NIST traceable elemental Hg standards means either:

(1) Compressed gas cylinders having known concentrations of elemental Hg, which have been prepared according to the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards''; or

(2) Calibration gases having known concentrations of elemental Hg, produced by a generator that fully meets the performance requirements of the ''EPA Traceability Protocol for Qualification and Certification of Elemental Mercury Gas Generators''.

* * * * *

NIST traceable source of oxidized Hg means a generator that: Is capable of providing known concentrations of vapor phase mercuric chloride ($HgCl_2$), and that fully meets the performance requirements of the ''EPA Traceability Protocol for Qualification and Certification of Oxidized Mercury Gas Generators''.

* * * * *

Qualified Individual means an individual who meets the requirements as described in ASTM D7036–04, ''Standard Practice for Competence of Air Emission Testing Bodies'' (incorporated by reference under § 75.6 of this part).

* * * * *

Specialty gas producer means an organization that prepares and analyzes compressed gas mixtures for use as calibration gases and that offers the mixtures for sale to end users or to third-party vendors for resale to end users.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

■ 3. The authority citation for Part 75 continues to read as follows:

Authority: 42 U.S.C. 7601, and 7651k, and 7651k note.

Subpart A—General

■ 4. Section 75.4 is amended by revising paragraph (d) to read as follows:

§ 75.4 Compliance dates.

* * * * *

(d) This paragraph, applies to affected units under the Acid Rain Program and to units subject to a State or Federal pollutant mass emissions reduction program that adopts the emission monitoring and reporting provisions of this part. In accordance with § 75.20, for an affected unit which, on the applicable compliance date, is either in long-term cold storage (as defined in § 72.2 of this chapter) or is shut down as the result of a planned outage or a forced outage, thereby preventing the required continuous monitoring system certification tests from being completed by the compliance date, the owner or operator shall provide notice of such unit storage or outage in accordance with § 75.61(a)(3) or § 75.61(a)(7), as applicable. For the planned and unplanned unit outages described in this paragraph, the owner or operator shall ensure that all of the continuous monitoring systems for SO_2, NO_X, CO_2, Hg, opacity, and volumetric flow rate required under this part (or under the applicable State or Federal mass emissions reduction program) are installed and that all required certification tests are completed no later than 90 unit operating days or 180 calendar days (whichever occurs first) after the date that the unit recommences commercial operation, notice of which date shall be provided under § 75.61(a)(3) or § 75.61(a)(7), as applicable. The owner or operator shall determine and report SO_2 concentration, NO_X emission rate, CO_2 concentration, Hg concentration, and flow rate data (as applicable) for all unit operating hours after the applicable compliance date until all of the required certification tests are successfully completed, using either:

(1) The maximum potential concentration of SO_2 (as defined in section 2.1.1.1 of appendix A to this part), the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter, the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, the maximum potential Hg concentration, as defined in section 2.1.7.1 of appendix A to this part, or the maximum potential CO_2 concentration, as defined in section 2.1.3.1 of appendix A to this part; or

(2) The conditional data validation provisions of § 75.20(b)(3); or

(3) Reference methods under § 75.22(b); or

(4) Another procedure approved by the Administrator pursuant to a petition under § 75.66.

* * * * *

■ 5. Section 75.6 is amended by:

■ a. Removing ''D129–91'' and adding in its place ''D129–00'', in paragraph (a)(1);

■ b. Removing ''D240–87 (Reapproved 1991)'' and adding in its place ''D240–00'', in paragraph (a)(2);

■ c. Removing ''D287–82 (Reapproved 1987)'' and adding in its place ''D287–92 (Reapproved 2000)'', in paragraph (a)(3);

■ d. Removing ''D388–92'' and adding in its place ''D388–99'', in paragraph (a)(4);

■ e. Removing and reserving paragraph (a)(5);

■ f. Removing ''D1072–90'' and adding in its place ''D1072–06'', and also by adding the phrase ''by Combustion and Barium Chloride Titration'' after the word ''Gases'', in paragraph (a)(6);

■ g. Removing ''D1217–91'' and adding in its place ''D1217–93 (Reapproved 1998)'', in paragraph (a)(7);

■ h. Removing the phrase ''(Reapproved 1990)'', and by removing ''D1250–80'' and adding in its place ''D1250–07'', and also by adding the phrase ''Use of the'' after the first occurrence of the word ''for'', in paragraph (a)(8);

■ i. Removing the phrase ''D1298–85 (Reapproved 1990), Standard Practice for Density, Relative Density (Specific Gravity)'' and adding in its place ''D1298–99, Standard Test Method for Density, Relative Density (Specific Gravity),'', in paragraph (a)(9);

■ j. Removing ''D1480–91'' and adding in its place ''D1480–93 (Reapproved 1997)'', in paragraph (a)(10);

■ k. Removing ''D1481–91'' and adding in its place ''D1481–93 (Reapproved 1997)'', in paragraph (a)(11);

■ l. Removing ''D1552–90'' and adding in its place ''D1552–01'', and also by removing the phrase, ''High Temperature'' and adding in its place ''High-Temperature'', in paragraph (a)(12);

■ m. Removing ''D1826–88'' and adding in its place ''D1826–94 (Reapproved 1998)'', in paragraph (a)(13);

■ n. Removing ''D1945–91'' and adding in its place ''D1945–96 (Reapproved 2001)'', in paragraph (a)(14);

■ o. Adding the phrase ''(Reapproved 2006)'' after ''D1946–90'', in paragraph (a)(15);

■ p. Removing and reserving paragraph (a)(16);

■ q. Removing ''D2013–86'' and adding in its place ''D2013–01'', and also by removing the phrase, ''Method of'', and adding in its place, ''Practice for'', in paragraph (a)(17);

■ r. Removing and reserving paragraph (a)(18);

■ s. Removing ''D2234–89'' and adding in its place ''D2234–00'', and also by removing the phrase ''Test Methods'', and adding in its place, ''Practice'', in paragraph (a)(19);

■ t. Removing and reserving paragraph (a)(20);

■ u. Removing ''D2502–87'' and adding in its place ''D2502–92 (Reapproved 1996)'', in paragraph (a)(21);

■ v. Removing ''D2503–82 (Reapproved 1987)'' and adding in its place ''D2503–92 (Reapproved 1997)'', and also by removing the phrase ''Molecular Weight (Relative Molecular Mass)'', and by adding in its place, ''Relative Molecular Mass (Molecular Weight)'', in paragraph (a)(22);

■ w. Removing ''D2622–92'' and adding in its place ''D2622–98'', and also by removing the phrase ''X-Ray Spectrometry'', and adding in its place ''Wavelength Dispersive X-ray Fluorescence Spectrometry'', in paragraph (a)(23);

■ x. Removing ''D3174–89'' and adding in its place ''D3174–00'', and also by removing the word ''From'' and adding in its place ''from'', in paragraph (a)(24);

■ y. Adding the phrase ''(Reapproved 2002)'' after ''D3176–89'', in paragraph (a)(25);

■ z. Removing ''D3177–89'' and adding in its place the phrase '' D3177–02 (Reapproved 2007)'' in paragraph (a)(26);

■ aa. Removing '' D3178–89 (1997), ''Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke'' and adding in its place ''D5373–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke'' in paragraph (a)(27);

■ bb. Removing ''D3238–90'' and adding in its place ''D3238–95 (Reapproved 2000)'', in paragraph (a)(28);

■ cc. Removing ''D3246–81 (Reapproved 1987)'' and adding in its place ''D3246–96'', and also by removing the word ''By'' and adding in its place, ''by'', in paragraph (a)(29);

■ dd. Removing and reserving paragraph (a)(30);

■ ee. Removing ''D3588–91'' and adding in its place ''D3588–98'', and also by removing the phrase, ''(Specific Gravity)'', in paragraph (a)(31);

■ ff. Removing ''D4052–91'' and adding in its place ''D4052–96 (Reapproved 2002)'', in paragraph (a)(32);

■ gg. Removing ''D4057–88'' and adding in its place ''D4057–95 (Reapproved 2000)'', in paragraph (a)(33);

■ hh. Removing ''D4177–82 (Reapproved 1990)'' and adding in its place ''D4177–95 (Reapproved 2000)'', in paragraph (a)(34);

■ ii. Removing ''D4239–85'' and adding in its place ''D4239–02'', and also by removing the phrase ''High Temperature'', and adding in its place ''High-Temperature'', in paragraph (a)(35);

■ jj. Removing ''D4294–90'' and adding in its place ''D4294–98'', adding the words ''and Petroleum'' after the word ''Petroleum'', by removing the word ''X-Ray'' and adding in its place, ''X-ray'', and by removing the word ''Spectroscopy'' and adding in its place, ''Spectrometry'' in paragraph (a)(36);

■ kk. Removing the phrase ''(Reapproved 1989)'' and adding in its place the phrase ''(Reapproved 2006)'', in paragraph (a)(37);

■ ll. Removing ''(reapproved 2004)'', and adding in its place, ''(Reapproved 2004)'', in paragraph (a)(38);

■ mm. Adding the phrase ''(Reapproved 2006)'' after ''D4891–89'', in paragraph (a)(39);

■ nn. Removing ''D5291–92'' and adding in its place ''D5291–02'', in paragraph (a)(40);

■ oo. Removing ''D5373–93'', and adding in its place ''D5373–02 (Reapproved 2007)'' and adding the word ''Test'' after the word ''Standard'', in paragraph (a)(41);

■ pp. Removing ''D5504–94'' and adding in its place ''D5504–01'', in paragraph (a)(42);

■ qq. Adding new paragraphs (a)(45), (a)(46), (a)(47), (a)(48), and (a)(49);

■ rr. Removing the phrase ''ASME MFC–3M–1989 with September 1990 Errata'' and adding in its place the phrase ''ASME MFC–3M–2004 (Revision of ASME MFC–3M–1989 (R1995))'', in paragraph (b)(1);

■ ss. Removing the date ''1990'' and adding in its place the date ''1997'' in the parenthetical, in paragraph (b)(2);

■ tt. Adding the phrase ''(Reaffirmed 1994)'' after ''ASME–MFC–5M–1985,'', in paragraph (b)(3);

■ uu. Removing the phrase ''1987 with June 1987 Errata'' and adding in its

place the number ''1998'' at the end of ''MFC–6M–'', and also by removing ''Flow Meters'' and adding in its place, ''Flowmeters'', in paragraph (b)(4);

■ vv. Removing the phrase ''with December 1989 Errata'' and adding in its place the phrase ''(Reaffirmed 2001)'', in paragraph (b)(6);

■ ww. Removing the number ''86'' and adding in its place the number ''96'' at the end of ''GPA Standard 2172–'', in paragraph (d)(1);

■ xx. Removing the number ''90'' and adding in its place the number ''00'' at the end of ''GPA Standard 2261–00'', in paragraph (d)(2);

■ yy. Revising paragraphs (f)(1) and (f)(3); and

■ zz. Adding new paragraph (f)(4).

The revisions and additions read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(a) * * *

(45) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, for appendix D of this part.

(46) ASTM D4809–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), for appendices D and F of this part.

(47) ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke, for appendices A, D, and F of this part.

(48) ASTM D7036–04, Standard Practice for Competence of Air Emission Testing Bodies, for appendices A, B, and E of this part.

(49) ASTM D5453–06, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence, for appendix D of this part.

* * * * *

(f) * * *

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3—Tank Gauging, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005; Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001; Section 2—Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, First Edition, August 1995 (Reaffirmed March 2006); Section 3—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996; Section 4—Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, First Edition April 1995 (Reaffirmed, March 2006); and Section 5—Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, First Edition March 1997 (Reaffirmed, March 2003); for § 75.19.

* * * * *

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems, Section 2—Pipe Provers (Provers Accumulating at Least 10,000 Pulses), Second Edition, March 2001, and Section 5—Master-Meter Provers, Second Edition, May 2000, for appendix D to this part.

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices (First Edition, August 2005), for appendix D to this part.

■ 6. Section 75.11 is amended by:

■ a. Revising the heading of the section;

■ b. Adding the phrase ''and 14.0% for natural gas (boilers, only);'' after the word ''wood;'', in paragraph (b)(1);

■ c. Revising paragraph (d)(3);

■ d. Revising paragraphs (e) introductory text and (e)(1);

■ e. Removing and reserving paragraph (e)(2);

■ f. Revising paragraph (e)(3) introductory text;

■ g. Add new paragraph (e)(4); and

■ h. Revising paragraph (f).

The revisions and additions read as follows:

§ 75.11 Specific provisions for monitoring SO_2 emissions.

* * * * *

(d) * * *

(3) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b). If this option is selected for SO_2, the LME methodology must also be used for NO_X and CO_2 when these parameters are required to be monitored by applicable program(s).

(e) *Special considerations during the combustion of gaseous fuels.* The owner or operator of an affected unit that uses a certified flow monitor and a certified diluent gas (O_2 or CO_2) monitor to measure the unit heat input rate shall, during any hours in which the unit combusts only gaseous fuel, determine SO_2 emissions in accordance with paragraph (e)(1) or (e)(3) of this section, as applicable.

(1) If the gaseous fuel qualifies for a default SO_2 emission rate under Section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, the owner or operator may determine SO_2 emissions by using Equation F–23 in appendix F to this part. Substitute into Equation F–23 the hourly heat input, calculated using the certified flow monitoring system and the certified diluent monitor (according to the applicable equation in section 5.2 of appendix F to this part), in conjunction with the appropriate default SO_2 emission rate from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. When this option is chosen, the owner or operator shall perform the necessary data acquisition and handling system tests under § 75.20(c), and shall meet all quality control and quality assurance requirements in appendix B to this part for the flow monitor and the diluent monitor; or

(2) [Reserved]

(3) The owner or operator may determine SO_2 mass emissions by using a certified SO_2 continuous monitoring system, in conjunction with the certified flow rate monitoring system. However, if the gaseous fuel is very low sulfur fuel (as defined in § 72.2 of this chapter), the SO_2 monitoring system shall meet the following quality assurance provisions when the very low sulfur fuel is combusted:

* * * * *

(4) The provisions in paragraph (e)(1) of this section, may also be used for the combustion of a solid or liquid fuel that meets the definition of very low sulfur fuel in § 72.2 of this chapter, mixtures of such fuels, or combinations of such fuels with gaseous fuel, if the owner or operator submits a petition under § 75.66 for a default SO_2 emission rate for each fuel, mixture or combination, and if the Administrator approves the petition.

(f) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions for coal-fired units specified in paragraph (a) of this section, except where the owner or operator has an approved petition to use the provisions of paragraph (e)(1) of this section.

■ 7. Section 75.12 is amended by:

■ a. Revising the section heading;

■ b. Removing the word ''and'' before the number ''15.0%'', and by adding the phrase ''; and 18.0% for natural gas

(boilers, only)'' after the word ''wood'', in paragraph (b); and

■ c. Revising paragraph (e)(3).

The revisions read as follows:

§ 75.12 Specific provisions for monitoring NO_X emission rate.

* * * * *

(e) * * *

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_X emission rate and hourly NO_X mass emissions, if applicable under § 75.19(a) and (b). If this option is selected for NO_X, the LME methodology must also be used for SO_2 and CO_2 when these parameters are required to be monitored by applicable program(s).

* * * * *

■ 8. Section 75.13 is amended by revising paragraph (d)(3) to read as follows:

§ 75.13 Specific provisions for monitoring CO_2 emissions.

* * * * *

(d) * * *

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO_2 mass emissions, if applicable under § 75.19(a) and (b). If this option is selected for CO_2, the LME methodology must also be used for NO_X and SO_2 when these parameters are required to be monitored by applicable program(s).

■ 9. Section 75.14 is amended by adding paragraph (e) to read as follows:

§ 75.14 Specific provisions for monitoring opacity.

* * * * *

(e) Unit with a certified particulate matter (PM) monitoring system. If, for a particular affected unit, the owner or operator installs, certifies, operates, maintains, and quality-assures a continuous particulate matter (PM) monitoring system in accordance with Procedure 2 in appendix F to part 60 of this chapter, the unit shall be exempt from the opacity monitoring requirement of this part.

■ 10. Section 75.15 is amended by:

■ a. Removing the reference ''(j)'' and adding the reference ''(l)'' in its place in the introductory paragraph;

■ b. Revising paragraph (h); and

■ c. Adding paragraph (l).

The revisions and additions read as follows:

§ 75.15 Special provisions for measuring Hg mass emissions using the excepted sorbent trap monitoring methodology.

* * * * *

(h) The hourly Hg mass emissions for each collection period are determined using the results of the analyses in conjunction with contemporaneous hourly data recorded by a certified stack flow monitor, corrected for the stack gas moisture content. For each pair of sorbent traps analyzed, the average of the two Hg concentrations shall be used for reporting purposes under (75.84(f). Notwithstanding this requirement, if, due to circumstances beyond the control of the owner or operator, one of the paired traps is accidentally lost, damaged, or broken and cannot be analyzed, the results of the analysis of the other trap may be used for reporting purposes, provided that:

(1) The other trap has met all of the applicable quality-assurance requirements of this part; and

(2) The Hg concentration measured by the other trap is multiplied by a factor of 1.111.

* * * * *

(l) Whenever the type of sorbent material used by the traps is changed, the owner or operator shall conduct a diagnostic RATA of the modified sorbent trap monitoring system within 720 unit or stack operating hours after the date and hour when the new sorbent material is first used. If the diagnostic RATA is passed, data from the modified system may be reported as quality-assured, back to the date and hour when the new sorbent material was first used. If the RATA is failed, all data from the modified system shall be invalidated, back to the date and hour when the new sorbent material was first used, and data from the system shall remain invalid until a subsequent RATA is passed. If the required RATA is not completed within 720 unit or stack operating hours, but is passed on the first attempt, data from the modified system shall be invalidated beginning with the first operating hour after the 720 unit or stack operating hour window expires and data from the system shall remain invalid until the date and hour of completion of the successful RATA.

■ 11. Section 75.16 is amended by:

■ a. Revising paragraph (b)(1)(ii);

■ b. Adding the word ''rate'' after the phrase ''report heat input'' in the last sentence, in paragraph (e)(1); and

■ c. In the second sentence of paragraphs (e)(3) by removing both occurrences of the phrase ''steam flow'' and adding in its place the phrase ''steam load'' and adding the phrase ''or mmBtu/hr thermal output'' inside the parentheses, after the phrase ''in 1000 lb/hr'', in paragraph (e)(3).

The revisions read as follows:

§ 75.16 Special provisions for monitoring emissions from common, bypass, and multiple stacks for SO_2 emissions and heat input determinations.

* * * * *

(b) * * *

(1) * * *

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system and flow monitoring system in the common stack and combine emissions for the affected units for recordkeeping and compliance purposes.

* * * * *

■ 12. Section 75.17 is amended by revising paragraph (d)(2) to read as follows:

§ 75.17 Special provisions for monitoring emissions from common, bypass, and multiple stacks for NO_X emission rate.

* * * * *

(d) * * *

(2) Install, certify, operate, and maintain a NO_X-diluent CEMS only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under § 75.53, with respect to NO_X or any other parameter that is monitored only at the main stack. For each unit operating hour in which the bypass stack is used and the emissions are either uncontrolled (or the add-on controls are not documented to be operating properly), report the maximum potential NO_X emission rate (as defined in § 72.2 of this chapter). The maximum potential NO_X emission rate may be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). Alternatively, for a unit with NO_X add-on emission controls, for each unit operating hour in which the bypass stack is used and the add-on NO_X emission controls are not bypassed, the owner or operator may report the maximum controlled NO_X emission rate (MCR) instead of the maximum potential NO_X emission rate provided that the add-on controls are documented to be operating properly, as described in the quality assurance/quality control program for the unit, required by section 1 in appendix B of this part. To provide the necessary documentation, the owner or operator shall record parametric data to verify the proper operation of the NO_X add-on emission controls as described in § 75.34(d). Furthermore, the owner or operator shall calculate the MCR using the procedure described in section 2.1.2.1(b) of appendix A to this part where the words ''maximum potential NO_X emission rate (MER)'' shall apply instead of the words ''maximum

controlled NO_X emission rate (MCR)'' and by using the NO_X MEC in the calculations instead of the NO_X MPC.

■ 13. Section 75.19 is amended by:
■ a. Revising paragraph (a)(1);
■ b. Revising paragraph (c)(1)(i);
■ c. Revising paragraph (c)(1)(iv)(A)(3);
■ d. Removing the words ''Method 20'' from paragraph (c)(1)(iv)(A)(4);
■ e. Removing the words ''Method 20'' from the definition of NO_X obs in the nomenclature for Equation LM–1a under paragraph (c)(1)(iv)(A);
■ f. Adding the phrase, ''that meets the quality assurance requirements of either: this part, or appendix F to part 60 of this chapter, or a comparable State CEM program,'' after the abbreviation ''CEMS'', in paragraph (c)(1)(iv)(G);
■ g. Adding paragraphs (c)(1)(iv)(I)(3), (4), (5) and (6);
■ h. Revising paragraph (c)(3)(ii)(B)(2);
■ i. Revising paragraph (c)(3)(ii)(H);
■ j. Removing the words ''from Table LM–1 of this section'' from the first sentence of paragraph (c)(4)(i)(A);
■ k. Revising the heading for paragraph (c)(4)(ii); and
■ l. Adding paragraph (c)(4)(ii)(D).

The revisions and additions read as follows:

§ 75.19 Optional SO_2, NO_X, and CO_2 emissions calculation for low mass emissions units.

* * * * *

(a) * * *

(1) For units that meet the requirements of this paragraph (a)(1) and paragraphs (a)(2) and (b) of this section, the low mass emissions (LME) excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of methods under appendices D, E, and G to this part, for the purpose of determining unit heat input, NO_X, SO_2, and CO_2 mass emissions, and NO_X emission rate under this part. If the owner or operator of a qualifying unit elects to use the LME methodology, it must be used for all parameters that are required to be monitored by the applicable program(s). For example, for an Acid Rain Program LME unit, the methodology must be used to estimate SO_2, NO_X, and CO_2 mass emissions, NO_X emission rate, and unit heat input.

* * * * *

(c) * * *

(1) * * *

(i) If the unit combusts only natural gas and/or fuel oil, use Table LM–1 of this section to determine the appropriate SO_2 emission rate for use in calculating hourly SO_2 mass emissions under this section. Alternatively, for fuel oil combustion, a lower, fuel-specific SO_2 emission factor may be used in lieu of the applicable emission factor from Table LM–1, if a federally enforceable permit condition is in place that limits the sulfur content of the oil. If this alternative is chosen, the fuel-specific SO_2 emission rate in lb/mmBtu shall be calculated by multiplying the fuel sulfur content limit (weight percent sulfur) by 1.01. In addition, the owner or operator shall periodically determine the sulfur content of the oil combusted in the unit, using one of the oil sampling and analysis options described in section 2.2 of appendix D to this part, and shall keep records of these fuel sampling results in a format suitable for inspection and auditing. Alternatively, the required oil sampling and associated recordkeeping may be performed using a consensus standard (e.g., ASTM, API, etc.) that is prescribed in the unit's Federally-enforceable operating permit, in an applicable State regulation, or in another applicable Federal regulation. If the unit combusts gaseous fuel(s) other than natural gas, the owner or operator shall use the procedures in section 2.3.6 of appendix D to this part to document the total sulfur content of each such fuel and to determine the appropriate default SO2 emission rate for each such fuel.

* * * * *

(iv) * * *

(A) * * *

(3) Do not correct the NO_X concentration to 15% O_2.

* * * * *

(I) * * *

(*3*) The initial appendix E testing may be performed at a single load, between 75 and 100 percent of the maximum sustainable load defined in the monitoring plan for the unit, if the average annual capacity factor of the LME unit, when calculated according to the definition of ''capacity factor'' in § 72.2 of this chapter, is 2.5 percent or less for the three calendar years immediately preceding the year of the testing, and that the annual capacity factor does not exceed 4.0 percent in any of those three years. Similarly, for a LME unit that reports emissions data on an ozone season-only basis, the initial appendix E testing may be performed at a single load between 75 and 100 percent of the maximum sustainable load if the 2.5 and 4.0 percent capacity factor requirements are met for the three ozone seasons immediately preceding the date of the emission testing (see § 75.74(c)(11)). For a group of identical LME units, any unit(s) in the group that meet the 2.5 and 4.0 percent capacity factor requirements may perform the initial appendix E testing at a single load between 75 and 100 percent of the maximum sustainable load.

(*4*) The retest of any LME unit may be performed at a single load between 75 and 100 percent of the maximum sustainable load if, for the three calendar years immediately preceding the year of the retest (or, if applicable, the three ozone seasons immediately preceding the date of the retest), the applicable capacity factor requirements described in paragraph (c)(1)(iv)(I)(*3*) of this section are met.

(*5*) Alternatively, for combustion turbines, the single-load testing described in paragraphs (c)(1)(iv)(I)(*3*) and (c)(1)(iv)(I)(*4*) of this section may be performed at the highest attainable load level corresponding to the season of the year in which the testing is conducted.

(*6*) In all cases where the alternative single-load testing option described in paragraphs (c)(1)(iv)(I)(*3*) through (c)(1)(iv)(I)(*5*) of this section is used, the owner or operator shall keep records documenting that the required capacity factor requirements were met.

* * * * *

(3) * * *

(ii) * * *

(B) * * *

(*2*) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3-Tank Gauging, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005; Section 1B-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001; Section 2-Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, First Edition, August 1995 (Reaffirmed March 2006); Section 3-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, March 2001); Section 4-Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, First Edition April 1995 (Reaffirmed, September 2000); and Section 5-Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, First Edition March 1997 (Reaffirmed, March 2003); for § 75.19; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (all incorporated by reference under § 75.6 of this part); or

* * * * *

(H) For each low mass emissions unit or each low mass emissions unit in a

group of identical units, the owner or operator shall determine the cumulative quarterly unit load in megawatt hours or thousands of pounds of steam. The quarterly cumulative unit load shall be the sum of the hourly unit load values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM–5 or LM–6. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly cumulative load for the second calendar quarter of the year shall include only the unit loads for the months of May and June.

$$MW_{qtr} = \sum_{all-hours} MW \qquad \text{Eq. LM-5 (for MW output)}$$

$$ST_{qtr} = \sum_{all-hours} ST \qquad \text{Eq. LM-6 (for steam output)}$$

Where:

MW_{qtr} = Sum of all unit operating loads recorded during the quarter by the unit (MWh).

$ST_{fuel-qtr}$ = Sum of all hourly steam loads recorded during the quarter by the unit (klb of steam/hr).

MW = Unit operating load for a particular unit operating hour (MWh).

ST = Unit steam load for a particular unit operating hour (klb of steam).

* * * * *

(4) * * *

(ii) NO_X mass emissions and NO_X emission rate.

(D) The quarterly and cumulative NO_X emission rate in lb/mmBtu (if required by the applicable program(s)) shall be determined as follows. Calculate the quarterly NO_X emission rate by taking the arithmetic average of all of the hourly EF_{NO_X} values. Calculate the cumulative (year-to-date) NO_X emission rate by taking the arithmetic average of the quarterly NO_X emission rates.

* * * * *

■ 14. Section 75.20 is amended by:

■ a. Adding a new sentence after the third sentence of paragraph (b) introductory text;

■ b. Revising paragraph (c)(1)(v); and

■ c. Removing paragraphs (f)(1) and (f)(2).

The revisions and additions read as follows:

§ 75.20 Initial certification and recertification procedures.

* * * * *

(b) * * * The owner or operator shall also recertify the continuous emission monitoring systems for a unit that has recommenced commercial operation following a period of long-term cold storage as defined in § 72.2 of this chapter. * * *

* * * * *

(c) * * *

(1) * * *

(v) A cycle time test, (where, for the NO_X-diluent continuous emission monitoring system, the test is performed separately on the NO_X pollutant concentration monitor and the diluent gas monitor); and

* * * * *

§ 75.21 [Amended]

■ 15. Section 75.21 is amended by removing the words ''or (e)(2)'' at the end of the first sentence of paragraph (a)(4).

■ 16. Section 75.22 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraphs (a)(5), (a)(6), and (a)(7);

■ c. Revising paragraph (b) introductory text;

■ d. Removing the word ''and'' at the end of paragraph (b)(3);

■ e. Revising paragraph (b)(5);

■ f. Adding paragraphs (b)(6), (b)(7), and (b)(8); and

■ g. Revising paragraph (c)(1) introductory text.

The revisions and additions read as follows:

§ 75.22 Reference test methods.

(a) The owner or operator shall use the following methods, which are found in appendix A–4 to part 60 of this chapter or have been published by ASTM, to conduct the following tests: monitoring system tests for certification or recertification of continuous emission monitoring systems and excepted monitoring systems under appendix E to this part; the emission tests required under § 75.81(c) and (d); and required quality assurance and quality control tests:

* * * * *

(5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E in appendix A–4 to part 60 of this chapter, as applicable, are the reference methods for determining SO_2 and NO_X pollutant concentrations. (Methods 6A and 6B in appendix A–4 to part 60 of this chapter may also be used to determine SO_2 emission rate in lb/mmBtu.) Methods 7, 7A, 7C, 7D, or 7E in appendix A–4 to part 60 of this chapter must be used to measure total NO_X emissions, both NO and NO_2, for purposes of this part. The owner or operator shall not use the following sections, exceptions, and options of method 7E in appendix A–4 to part 60 of this chapter:

(i) Section 7.1 of the method allowing for use of prepared calibration gas mixtures that are produced in accordance with method 205 in Appendix M of 40 CFR Part 51;

(ii) The sampling point selection procedures in section 8.1 of the method, for the emission testing of boilers and combustion turbines under appendix E to this part. The number and location of the sampling points for those applications shall be as specified in sections 2.1.2.1 and 2.1.2.2 of appendix E to this part;

(iii) Paragraph (3) in section 8.4 of the method allowing for the use of a multi-hole probe to satisfy the multipoint traverse requirement of the method;

(iv) Section 8.6 of the method allowing for the use of ''Dynamic Spiking'' as an alternative to the interference and system bias checks of the method. Dynamic spiking may be conducted (optionally) as an additional quality assurance check.

(6) Method 3A in appendix A–2 and method 7E in appendix A–4 to part 60 of this chapter are the reference methods for determining NO_X and diluent emissions from stationary gas turbines for testing under appendix E to this part.

(7) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method) (incorporated by reference under § 75.6 of this part) is the reference method for determining Hg concentration.

(i) Alternatively, Method 29 in appendix A–8 to part 60 of this chapter may be used, with these caveats: The procedures for preparation of Hg

standards and sample analysis in sections 13.4.1.1 through 13.4.1.3 ASTM D6784–02 (incorporated by reference under § 75.6 of this part) shall be followed instead of the procedures in sections 7.5.33 and 11.1.3 of Method 29 in appendix A–8 to part 60 of this chapter, and the QA/QC procedures in section 13.4.2 of ASTM D6784–02 (incorporated by reference under § 75.6 of this part) shall be performed instead of the procedures in section 9.2.3 of Method 29 in appendix A–8 to part 60 of this chapter. The tester may also opt to use the sample recovery and preparation procedures in ASTM D6784–02 (incorporated by reference under § 75.6 of this part) instead of the Method 29 in appendix A–8 to part 60 of this chapter procedures, as follows: sections 8.2.8 and 8.2.9.1 of Method 29 in appendix A–8 to part 60 of this chapter may be replaced with sections 13.2.9.1 through 13.2.9.3 of ASTM D6784–02 (incorporated by reference under § 75.6 of this part); sections 8.2.9.2 and 8.2.9.3 of Method 29 in appendix A–8 to part 60 of this chapter may be replaced with sections 13.2.10.1 through 13.2.10.4 of ASTM D6784–02 (incorporated by reference under § 75.6 of this part); section 8.3.4 of Method 29 in appendix A–8 to part 60 of this chapter may be replaced with section 13.3.4 or 13.3.6 of ASTM D6784–02 (as appropriate) (incorporated by reference under § 75.6 of this part); and section 8.3.5 of Method 29 in appendix A–8 to part 60 of this chapter may be replaced with section 13.3.5 or 13.3.6 of ASTM D6784–02 (as appropriate) (incorporated by reference under § 75.6 of this part).

(ii) Whenever ASTM D6784–02 (incorporated by reference under § 75.6 of this part) or Method 29 in appendix A–8 to part 60 of this chapter is used, paired sampling trains are required. To validate a RATA run or an emission test run, the relative deviation (RD), calculated according to section 11.7 of appendix K to this part, must not exceed 10 percent, when the average concentration is greater than 1.0 $\mu g/m^3$. If the average concentration is ≤1.0 $\mu g/m^3$, the RD must not exceed 20 percent. The RD results are also acceptable if the absolute difference between the Hg concentrations measured by the paired trains does not exceed 0.03 $\mu g/m^3$. If the RD criterion is met, the run is valid. For each valid run, average the Hg concentrations measured by the two trains (vapor phase, only).

(iii) Two additional reference methods that may be used to measure Hg concentration are: Method 30A, ''Determination of Total Vapor Phase Mercury Emissions from Stationary Sources (Instrumental Analyzer Procedure)'' and Method 30B, ''Determination of Total Vapor Phase Mercury Emissions from Coal-Fired Combustion Sources Using Carbon Sorbent Traps''.

(iv) When Method 29 in appendix A–8 to part 60 of this chapter or ASTM D6784–02 (incorporated by reference under § 75.6 of this part) is used for the Hg emission testing required under §§ 75.81(c) and (d), locate the reference method test points according to section 8.1 of Method 30A, and if Hg stratification testing is part of the test protocol, follow the procedures in sections 8.1.3 through 8.1.3.5 of Method 30A.

(b) The owner or operator may use any of the following methods, which are found in appendix A to part 60 of this chapter or have been published by ASTM, as a reference method backup monitoring system to provide quality-assured monitor data:

* * * * *

(5) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method) (incorporated by reference under § 75.6 of this part) for determining Hg concentration;

(6) Method 29 in appendix A–8 to part 60 of this chapter for determining Hg concentration;

(7) Method 30A for determining Hg concentration; and

(8) Method 30B for determining Hg concentration.

(c)(1) Instrumental EPA Reference Methods 3A, 6C, and 7E in appendices A–2 and A–4 of part 60 of this chapter shall be conducted using calibration gases as defined in section 5 of appendix A to this part. Otherwise, performance tests shall be conducted and data reduced in accordance with the test methods and procedures of this part unless the Administrator:

* * * * *

■ 17. Section 75.31 is amended by adding a sentence to the end of paragraph (c)(3) to read as follows:

§ 75.31 Initial missing data procedures.

* * * * *

(c) * * *

(3) * * * Alternatively, where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly during the hour, as provided in § 75.34(d), the owner or operator may substitute, as applicable, the maximum controlled NO_X emission rate (MCR) or the maximum expected NO_X concentration (MEC).

* * * * *

■ 18. Section 75.32 is amended by revising paragraph (b) to read as follows:

§ 75.32 Determination of monitor data availability for standard missing data procedures.

* * * * *

(b) The monitor data availability shall be calculated for each hour during each missing data period. The owner or operator shall record the percent monitor data availability for each hour of each missing data period to implement the missing data substitution procedures.

* * * * *

■ 19. Section 75.33 is amended by:

■ a. Revising the section heading;

■ b. Removing the word ''Whenever'' and adding in its place the word ''If'', and by removing the words ''each hour of each'' and adding in its place the words ''that hour of the'', in paragraph (b)(1) introductory text;

■ c. Removing the word ''Whenever'' and adding in its place the word ''If'', and by removing the words ''each hour of each'' and adding in its place the words ''that hour of the'', in paragraph (b)(2) introductory text;

■ d. Removing the word ''Whenever'' and adding in its place the word ''If'', and by removing the word ''each'' and adding in its place the words ''that hour of the'', in paragraphs (b)(3) and (b)(4);

■ e. Removing the word ''Whenever'' and adding in its place the word ''If'', and by removing the words ''each hour of each'' and adding in its place the words ''that hour of the'', in paragraphs (c)(1) introductory text, (c)(2) introductory text, (c)(3), and (c)(4);

■ f. Revising paragraph (c)(8)(iii);

■ g. Revising Tables 1 and 2 in paragraph (c)(8)(iv);

■ h. Removing the word ''Whenever'' and adding in its place the word ''If'', and by removing the words ''each hour of each'' and adding in its place the words ''that hour of the'', in paragraphs (d)(1) introductory text, (d)(2) introductory text, (d)(3) introductory text, and (d)(4) introductory text.

■ i. Revising Table 3 in paragraph (e)(3); and

The revisions and additions read as follows:

§ 75.33 Standard missing data procedures for SO_2, NO_X, Hg, and flow rate.

* * * * *

(c) * * *

(8) * * *

(iii) For the purposes of providing substitute data under paragraph (c)(4) of this section, a separate, fuel-specific maximum potential concentration (MPC), maximum potential NO_X emission rate (MER), or maximum

potential flow rate (MPF) value (as applicable) shall be determined for each type of fuel combusted in the unit, in a manner consistent with § 72.2 of this chapter and with section 2.1.2.1 or 2.1.4.1 of appendix A to this part. For co-firing, the MPC, MER or MPF value shall be based on the fuel with the highest emission rate or flow rate (as applicable). Furthermore, for a unit with add-on NO_X emission controls, a separate fuel-specific maximum controlled NO_X emission rate (MCR) or maximum expected NO_X concentration (MEC) value (as applicable) shall be determined for each type of fuel combusted in the unit. The exact methodology used to determine each fuel-specific MPC, MER, MEC, MCR or MPF value shall be documented in the monitoring plan for the unit or stack.

(iv) * * *

TABLE 1.—MISSING DATA PROCEDURE FOR SO_2 CEMS, CO_2 CEMS, MOISTURE CEMS, HG CEMS, AND DILUENT (CO_2 OR O_2) MONITORS FOR HEAT INPUT DETERMINATION

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) [2]	Method	Lookback period
95 or more (90 or more for Hg)	N ≤ 24	Average	HB/HA.
	N > 24	For SO_2, CO_2, Hg, and H_2O **, the greater of:	
		Average	HB/HA.
		90th percentile	720 hours.*
		For O_2 and H_2O^X, the lesser of:	
		10th percentile	HB/HA.
			720 hours.*
90 or more, but below 95 (> 80 but < 90 for Hg)	N ≤ 8	Average	HB/HA.
	N > 8	For SO_2, CO_2, Hg, and H_2O **, the greater of:	
		Average	HB/HA.
		95th percentile	720 hours.*
		For O_2 and H_2O^X, the lesser of:	
		Average	HB/HA.
		5th Percentile	720 hours.*
80 or more, but below 90 (> 70 but < 80 for Hg)	N > 0	For SO_2, CO_2, Hg, and H_2O: **	
		Maximum value [1]	720 hours.*
		For O_2 and H_2O^X:	
		Minimum value [1]	720 hours.*
Below 80 (Below 70 for Hg)	N > 0	Maximum potential concentration [3] or % (for SO_2, CO_2, Hg, and H_2O **) *or*	
		Minimum potential concentration or % (for O_2 and H_2O^X).	None.

HB/HA = hour before and hour after the CEMS outage.

* Quality-assured, monitor operating hours, during unit operation. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than 3 years prior to the missing data period.

[1] Where a unit with add-on SO_2 or Hg emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled concentration from the previous 720 quality-assured monitor operating hours.

[2] During unit operating hours.

[3] Alternatively, where a unit with add-on SO_2 or Hg emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected SO_2 or Hg concentration or (b) 1.25 times the maximum controlled value from the previous 720 quality-assured monitor operating hours.

[X] Use this algorithm for moisture except when Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A–7 to part 60 of this chapter is used for NO_X emission rate.

** Use this algorithm for moisture *only* when Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A–7 to part 60 of this chapter is used for NO_X emission rate.

TABLE 2.—LOAD-BASED MISSING DATA PROCEDURE FOR NO_X-DILUENT CEMS, NO_X CONCENTRATION CEMS AND FLOW RATE CEMS

Trigger conditions		Calculation routines		
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) [2]	Method	Lookback period	Load ranges
95 or more	N ≤ 24	Average	2,160 hours *	Yes.
	N > 24	The greater of:		
		Average	HB/HA	No.
		90th percentile	2,160 hours *	Yes.
90 or more, but below 95	N ≤ 8	Average	2,160 hours *	Yes.
	N > 8	The greater of:		
		Average	HB/HA	No.
		95th percentile	2,160 hours *	Yes.
80 or more, but below 90	N > 0	Maximum value [1]	2,160 hours *	Yes.

TABLE 2.—LOAD-BASED MISSING DATA PROCEDURE FOR NO_X-DILUENT CEMS, NO_X CONCENTRATION CEMS AND FLOW RATE CEMS—Continued

Trigger conditions		Calculation routines		
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) [2]	Method	Lookback period	Load ranges
Below 80	N > 0	Maximum potential NO_X emission rate [3]; or maximum potential NO_X concentration [3]; or maximum potential flow rate.	None	No.

HB/HA = hour before and hour after the CEMS outage.

* Quality-assured, monitor operating hours, using data at the corresponding load range (''load bin'') for each hour of the missing data period. May be either fuel-specific or non-fuel-specific. For units that report data only for the ozone season, include only quality assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.

[1] Where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled NO_X concentration or emission rate from the previous 2,160 quality-assured monitor operating hours. Units with add-on controls that report NO_X mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season data pools to provide substitute data values, as described in § 75.34(a)(2).

[2] During unit operating hours.

[3] Alternatively, where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected NO_X concentration (or maximum controlled NO_X emission rate, as applicable); or (b) 1.25 times the maximum controlled value at the corresponding load bin, from the previous 2,160 quality-assured monitor operating hours.

* * * * *

(e) * * *

(3) * * *

TABLE 3.—NON-LOAD-BASED MISSING DATA PROCEDURE FOR NO_X-DILUENT CEMS AND NO_X CONCENTRATION CEMS

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) [1]	Method	Lookback period
95 or more	N ≤ 24	Average	2,160 hours.*
	N > 24	90th percentile	2,160 hours.*
90 or more, but below 95	N ≤ 8	Average	2,160 hours.*
	N > 8	95th percentile	2,160 hours.*
80 or more, but below 90	N > 0	Maximum value [3]	2,160 hours.*
Below 80, or operational bin indeterminable	N > 0	Maximum potential NO_X emission rate [2] or maximum potential NO_X concentration [2].	None.

* If operational bins are used, the lookback period is 2,160 quality-assured, monitor operating hours, and data at the corresponding operational bin are used to provide substitute data values. If operational bins are not used, the lookback period is the previous 2,160 quality-assured monitor operating hours. For units that report data only for the ozone season, include only quality-assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.

[1] During unit operation.

[2] Alternatively, where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly, as provided in § 75.34, the unit may report the greater of: (a) the maximum expected NO_X concentration, (or maximum controlled NO_X emission rate, as applicable); or (b) 1.25 times the maximum controlled value at the corresponding operational bin (if applicable), from the previous 2,160 quality-assured monitor operating hours.

[3] Where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly during the missing data period, as provided in § 75.34, the unit may use the maximum controlled NO_X concentration or emission rate from the previous 2,160 quality-assured monitor operating hours. Units with add-on controls that report NO_X mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season data pools to provide substitute data values, as described in § 75.34(a)(2).

* * * * *

■ 20. Section 75.34 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. In paragraph (a)(2)(ii) by removing the words ''and (c)(3)'' and adding in its place the words '', (c)(3) and (c)(5) of this section, and § 75.38(c),''

■ c. Revising paragraph (a)(3);

■ d. Adding paragraph (a)(5); and

■ e. In paragraph (d) by removing the words ''paragraphs (a)(1) and (a)(3) of this section,'' and adding in its place the words ''paragraphs (a)(1), (a)(3) and (a)(5) of this section; and §§ 75.31(c)(3), 75.38(c), and 75.72(c)(3),''.

The revisions and additions read as follows:

§ 75.34 Units with add-on emission controls.

(a) The owner or operator of an affected unit equipped with add-on SO_2 and/or NO_X emission controls shall provide substitute data in accordance with paragraphs (a)(1), through (a)(5) of this section for each hour in which quality-assured data from the outlet SO_2 and/or NO_X monitoring system(s) are not obtained.

* * * * *

(3) For each missing data hour in which the percent monitor data availability for SO_2 or NO_X, calculated in accordance with § 75.32, is less than 90.0 percent and is greater than or equal to 80.0 percent; and parametric data establishes that the add-on emission controls were operating properly (*i.e.* within the range of operating parameters provided in the quality assurance/

quality control program) during the hour, the owner or operator may:

(i) Replace the maximum SO_2 concentration recorded in the 720 quality-assured monitor operating hours immediately preceding the missing data period, with the maximum controlled SO2 concentration recorded in the previous 720 quality-assured monitor operating hours; or

(ii) Replace the maximum NO_X concentration(s) or NO_X emission rate(s) from the appropriate load bin(s) (based on a lookback through the 2,160 quality-assured monitor operating hours immediately preceding the missing data period), with the maximum controlled NO_X concentration(s) or emission rate(s) from the appropriate load bin(s) in the same 2,160 quality-assured monitor operating hour lookback period.

* * * * *

(5) For each missing data hour in which the percent monitor data availability for SO_2 or NO_X, calculated in accordance with § 75.32, is below 80.0 percent and parametric data establish that the add-on emission controls were operating properly (*i.e.* within the range of operating parameters provided in the quality assurance/quality control program),in lieu of reporting the maximum potential value, the owner or operator may substitute, as applicable, the greater of:

(i) The maximum expected SO_2 concentration or 1.25 times the maximum hourly controlled SO_2 concentration recorded in the previous 720 quality-assured monitor operating hours;

(ii) The maximum expected NO_X concentration or 1.25 times the maximum hourly controlled NO_X concentration recorded in the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin;

(iii) The maximum controlled hourly NO_X emission rate (MCR) or 1.25 times the maximum hourly controlled NO_X emission rate recorded in the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin;

(iv) For the purposes of implementing the missing data options in paragraphs (a)(5)(i) through (a)(5)(iii) of this section, the maximum expected SO_2 and NO_X concentrations shall be determined, respectively, according to sections 2.1.1.2 and 2.1.2.2 of appendix A to this part. The MCR shall be calculated according to the basic procedure described in section 2.1.2.1(b) of appendix A to this part, except that the words ''maximum potential NO_X emission rate (MER)'' shall be replaced with the words ''maximum controlled NO_X emission rate (MCR)'' and the NO_X MEC shall be used instead of the NO_X MPC.

* * * * *

■ 20. Section 75.38 is amended by revising paragraphs (a) and (c) to read as follows.

§ 75.38 Standard missing data procedures for Hg CEMS.

(a) Once 720 quality assured monitor operating hours of Hg concentration data have been obtained following initial certification, the owner or operator shall provide substitute data for Hg concentration in accordance with the procedures in (75.33(b)(1) through (b)(4), except that the term ''Hg concentration'' shall apply rather than ''SO_2 concentration,'' the term ''Hg concentration monitoring system'' shall apply rather than ''SO_2 pollutant concentration monitor,'' the term ''maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part'' shall apply, rather than ''maximum potential SO_2 concentration'', and the percent monitor data availability trigger conditions prescribed for Hg in Table 1 of § 75.33 shall apply rather than the trigger conditions prescribed for SO_2.

* * * * *

(c) For units with FGD systems or add-on Hg emission controls, when the percent monitor data availability is less than 80.0 percent and is greater than or equal to 70.0 percent, and a missing data period occurs, consistent with § 75.34(a)(3), for each missing data hour in which the FGD or Hg emission controls are documented to be operating properly, the owner or operator may report the maximum controlled Hg concentration recorded in the previous 720 quality-assured monitor operating hours. In addition, when the percent monitor data availability is less than 70.0 percent and a missing data period occurs, consistent with § 75.34(a)(5), for each missing data hour in which the FGD or Hg emission controls are documented to be operating properly, the owner or operator may report the greater of the maximum expected Hg concentration (MEC) or 1.25 times the maximum controlled Hg concentration recorded in the previous 720 quality-assured monitor operating hours. The MEC shall be determined in accordance with section 2.1.7.1 of appendix A to this part.

■ 21. Section 75.39 is amended by:

■ a. Revising paragraph (a);

■ b. Revising paragraph (b);

■ c. Revising paragraph (c);

■ d. Revising paragraph (d); and

■ e. Adding paragraph (f).

The revisions and additions read as follows:

§ 75.39 Missing data procedures for sorbent trap monitoring systems.

(a) If a primary sorbent trap monitoring system has not been certified by the applicable compliance date specified under a State or Federal Hg mass emission reduction program that adopts the requirements of subpart I of this part, and if quality-assured Hg concentration data from a certified backup Hg monitoring system, reference method, or approved alternative monitoring system are unavailable, the owner or operator shall report the maximum potential Hg concentration, as defined in section 2.1.7 of appendix A to this part, until the primary system is certified.

(b) For a certified sorbent trap system, a missing data period will occur in the following circumstances, unless quality-assured Hg concentration data from a certified backup Hg CEMS, sorbent trap system, reference method, or approved alternative monitoring system are available:

(1) A gas sample is not extracted from the stack during unit operation (e.g., during a monitoring system malfunction or when the system undergoes maintenance); or

(2) The results of the Hg analysis for the paired sorbent traps are missing or invalid (as determined using the quality assurance procedures in appendix K to this part). The missing data period begins with the hour in which the paired sorbent traps for which the Hg analysis is missing or invalid were put into service. The missing data period ends at the first hour in which valid Hg concentration data are obtained with another pair of sorbent traps (i.e., the hour at which this pair of traps was placed in service), or with a certified backup Hg CEMS, reference method, or approved alternative monitoring system.

(c) *Initial missing data procedures.* Use the missing data procedures in § 75.31(b) until 720 hours of quality-assured Hg concentration data have been collected with the sorbent trap monitoring system(s), following initial certification.

(d) *Standard missing data procedures.* Once 720 quality-assured hours of data have been obtained with the sorbent trap system(s), begin reporting the percent monitor data availability in accordance with § 75.32 and switch from the initial missing data procedures in paragraph (c) of this section to the standard missing data procedures in § 75.38.

* * * * *

(f) In cases where the owner or operator elects to use a primary Hg CEMS and a certified redundant (or non-redundant) backup sorbent trap monitoring system (or vice-versa), when both the primary and backup monitoring systems are out-of-service and quality-assured Hg concentration data from a temporary like-kind replacement analyzer, reference method, or approved alternative monitoring system are unavailable, the previous 720 quality-assured monitor operating hours reported in the electronic quarterly report under § 75.64 shall be used for the required missing data lookback, irrespective of whether these data were recorded by the Hg CEMS, the sorbent trap system, a temporary like-kind replacement analyzer, a reference method, or an approved alternative monitoring system.

■ 22. Section 75.53 is amended by:
■ a. Revising paragraph (a)(1);
■ b. Removing the phrase ''(d) or (f)'' and adding in its place the phrase ''(f) or (h)'' in the second sentence of paragraph (a)(2);
■ c. Adding paragraph (e)(1)(xiv); and
■ d. Adding paragraphs (g) and (h).

The revisions and additions read as follows:

§ 75.53 Monitoring plan.

(a) * * *

(1) The provisions of paragraphs (e) and (f) of this section shall be met through December 31, 2008. The owner or operator shall meet the requirements of paragraphs (a), (b), (e), and (f) of this section through December 31, 2008, except as otherwise provided in paragraph (g) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a), (b), (g), and (h) of this section only. In addition, the provisions in paragraphs (g) and (h) of this section that support a regulatory option provided in another section of this part must be followed if the regulatory option is used prior to January 1, 2009.

* * * * *

(e) * * *

(1) * * *

(xiv) For each unit with a flow monitor installed on a rectangular stack or duct, if a wall effects adjustment factor (WAF) is determined and applied to the hourly flow rate data:

(A) Stack or duct width at the test location, ft;

(B) Stack or duct depth at the test location, ft;

(C) Wall effects adjustment factor (WAF), to the nearest 0.0001;

(D) Method of determining the WAF;

(E) WAF Effective date and hour;

(F) WAF no longer effective date and hour (if applicable);

(G) WAF determination date;

(H) Number of WAF test runs;

(I) Number of Method 1 traverse points in the WAF test;

(J) Number of test ports in the WAF test; and

(K) Number of Method 1 traverse points in the reference flow RATA.

* * * * *

(g) *Contents of the monitoring plan.* The requirements of paragraphs (g) and (h) of this section shall be met on and after January 1, 2009. Notwithstanding this requirement, the provisions of paragraphs (g) and (h) of this section may be implemented prior to January 1, 2009, as follows. In 2008, the owner or operator may opt to record and report the monitoring plan information in paragraphs (g) and (h) of this section, in lieu of recording and reporting the information in paragraphs (e) and (f) of this section. Each monitoring plan shall contain the information in paragraph (g)(1) of this section in electronic format and the information in paragraph (g)(2) of this section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

(1) *Electronic.* (i) The facility ORISPL number developed by the Department of Energy and used in the National Allowance Data Base (or equivalent facility ID number assigned by EPA, if the facility does not have an ORISPL number). Also provide the following information for each unit and (as applicable) for each common stack and/or pipe, and each multiple stack and/or pipe involved in the monitoring plan:

(A) A representation of the exhaust configuration for the units in the monitoring plan. Provide the ID number of each unit and assign a unique ID number to each common stack, common pipe multiple stack and/or multiple pipe associated with the unit(s) represented in the monitoring plan. For common and multiple stacks and/or pipes, provide the activation date and deactivation date (if applicable) of each stack and/or pipe;

(B) Identification of the monitoring system location(s) (e.g., at the unit-level, on the common stack, at each multiple stack, etc.). Provide an indicator (''flag'') if the monitoring location is at a bypass stack or in the ductwork (breeching);

(C) The stack exit height (ft) above ground level and ground level elevation above sea level, and the inside cross-sectional area (ft^2) at the flue exit and at the flow monitoring location (for units with flow monitors, only). Also use appropriate codes to indicate the material(s) of construction and the shape(s) of the stack or duct cross-section(s) at the flue exit and (if applicable) at the flow monitor location;

(D) The type(s) of fuel(s) fired by each unit. Indicate the start and (if applicable) end date of combustion for each type of fuel, and whether the fuel is the primary, secondary, emergency, or startup fuel;

(E) The type(s) of emission controls that are used to reduce SO_2, NO_X, Hg, and particulate emissions from each unit. Also provide the installation date, optimization date, and retirement date (if applicable) of the emission controls, and indicate whether the controls are an original installation;

(F) Maximum hourly heat input capacity of each unit; and

(G) A non-load based unit indicator (if applicable) for units that do not produce electrical or thermal output.

(ii) For each monitored parameter (e.g., SO_2, NO_X, flow, etc.) at each monitoring location, specify the monitoring methodology and the missing data approach for the parameter. If the unmonitored bypass stack approach is used for a particular parameter, indicate this by means of an appropriate code. Provide the activation date/hour, and deactivation date/hour (if applicable) for each monitoring methodology and each missing data approach.

(iii) For each required continuous emission monitoring system, each fuel flowmeter system, each continuous opacity monitoring system, and each sorbent trap monitoring system (as defined in § 72.2 of this chapter), identify and describe the major monitoring components in the monitoring system (e.g., gas analyzer, flow monitor, opacity monitor, moisture sensor, fuel flowmeter, DAHS software, etc.). Other important components in the system (e.g., sample probe, PLC, data logger, etc.) may also be represented in the monitoring plan, if necessary. Provide the following specific information about each component and monitoring system:

(A) For each required monitoring system:

(*1*) Assign a unique, 3-character alphanumeric identification code to the system;

(*2*) Indicate the parameter monitored by the system;

(*3*) Designate the system as a primary, redundant backup, non-redundant backup, data backup, or reference method backup system, as provided in § 75.10(e); and

(*4*) Indicate the system activation date/hour and deactivation date/hour (as applicable).

(B) For each component of each monitoring system represented in the monitoring plan:

(*1*) Assign a unique, 3-character alphanumeric identification code to the component;

(*2*) Indicate the manufacturer, model and serial number;

(*3*) Designate the component type;

(*4*) For dual-span applications, indicate whether the analyzer component ID represents a high measurement scale, a low scale, or a dual range;

(*5*) For gas analyzers, indicate the moisture basis of measurement;

(*6*) Indicate the method of sample acquisition or operation, (e.g., extractive pollutant concentration monitor or thermal flow monitor); and

(*7*) Indicate the component activation date/hour and deactivation date/hour (as applicable).

(iv) Explicit formulas, using the component and system identification codes for the primary monitoring system, and containing all constants and factors required to derive the required mass emissions, emission rates, heat input rates, etc. from the hourly data recorded by the monitoring systems. Formulas using the system and component ID codes for backup monitoring systems are required only if different formulas for the same parameter are used for the primary and backup monitoring systems (e.g., if the primary system measures pollutant concentration on a different moisture basis from the backup system). Provide the equation number or other appropriate code for each emissions formula (e.g., use code F–1 if Equation F–1 in appendix F to this part is used to calculate SO_2 mass emissions). Also identify each emissions formula with a unique three character alphanumeric code. The formula effective start date/hour and inactivation date/hour (as applicable) shall be included for each formula. The owner or operator of a unit for which the optional low mass emissions excepted methodology in § 75.19 is being used is not required to report such formulas.

(v) For each parameter monitored with CEMS, provide the following information:

(A) Measurement scale (high or low);

(B) Maximum potential value (and method of calculation). If NO_X emission rate in lb/mmBtu is monitored, calculate and provide the maximum potential NO_X emission rate in addition to the maximum potential NO_X concentration;

(C) Maximum expected value (if applicable) and method of calculation;

(D) Span value(s) and full-scale measurement range(s);

(E) Daily calibration units of measure;

(F) Effective date/hour, and (if applicable) inactivation date/hour of each span value;

(G) An indication of whether dual spans are required; and

(H) The default high range value (if applicable) and the maximum allowable low-range value for this option.

(vi) If the monitoring system or excepted methodology provides for the use of a constant, assumed, or default value for a parameter under specific circumstances, then include the following information for each such value for each parameter:

(A) Identification of the parameter;

(B) Default, maximum, minimum, or constant value, and units of measure for the value;

(C) Purpose of the value;

(D) Indicator of use, i.e., during controlled hours, uncontrolled hours, or all operating hours;

(E) Type of fuel;

(F) Source of the value;

(G) Value effective date and hour;

(H) Date and hour value is no longer effective (if applicable); and

(I) For units using the excepted methodology under § 75.19, the applicable SO_2 emission factor.

(vii) Unless otherwise specified in section 6.5.2.1 of appendix A to this part, for each unit or common stack on which hardware CEMS are installed:

(A) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in 1000 lb/hr (i.e., klb/hr), rounded to the nearest klb/hr, or thermal output in mmBtu/hr, rounded to the nearest mmBtu/hr), for units that produce electrical or thermal output;

(B) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts, thousands of lb/hr of steam, mmBtu/hr of thermal output, or ft/sec (as applicable);

(C) Except for peaking units, identify the most frequently and second most frequently used load (or operating) levels (i.e., low, mid, or high) in accordance with section 6.5.2.1 of appendix A to this part, expressed in megawatts, thousands of lb/hr of steam, mmBtu/hr of thermal output, or ft/sec (as applicable);

(D) Except for peaking units, an indicator of whether the second most frequently used load (or operating) level is designated as normal in section 6.5.2.1 of appendix A to this part;

(E) The date of the data analysis used to determine the normal load (or operating) level(s) and the two most frequently-used load (or operating) levels (as applicable); and

(F) Activation and deactivation dates and hours, when the maximum hourly gross load, boundaries of the range of operation, normal load (or operating) level(s) or two most frequently-used load (or operating) levels change and are updated.

(viii) For each unit for which CEMS are not installed:

(A) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in klb/hr, rounded to the nearest klb/hr, or steam load in mmBtu/hr, rounded to the nearest mmBtu/hr);

(B) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part), expressed in megawatts, mmBtu/hr of thermal output, or thousands of lb/hr of steam;

(C) Except for peaking units and units using the low mass emissions excepted methodology under § 75.19, identify the load level designated as normal, pursuant to section 6.5.2.1 of appendix A to this part, expressed in megawatts, mmBtu/hr of thermal output, or thousands of lb/hr of steam;

(D) The date of the load analysis used to determine the normal load level (as applicable); and

(E) Activation and deactivation dates and hours, when the maximum hourly gross load, boundaries of the range of operation, or normal load level change and are updated.

(ix) For each unit with a flow monitor installed on a rectangular stack or duct, if a wall effects adjustment factor (WAF) is determined and applied to the hourly flow rate data:

(A) Stack or duct width at the test location, ft;

(B) Stack or duct depth at the test location, ft;

(C) Wall effects adjustment factor (WAF), to the nearest 0.0001;

(D) Method of determining the WAF;

(E) WAF Effective date and hour;

(F) WAF no longer effective date and hour (if applicable);

(G) WAF determination date;

(H) Number of WAF test runs;

(I) Number of Method 1 traverse points in the WAF test;

(J) Number of test ports in the WAF test; and

(K) Number of Method 1 traverse points in the reference flow RATA.

(2) *Hardcopy.* (i) Information, including (as applicable): Identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity

check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, maximum potential NO_X emission rate, and span; and apportionment strategies under §§ 75.10 through 75.18.

(ii) Description of site locations for each monitoring component in the continuous emission or opacity monitoring systems, including schematic diagrams and engineering drawings specified in paragraphs (e)(2)(iv) and (e)(2)(v) of this section and any other documentation that demonstrates each monitor location meets the appropriate siting criteria.

(iii) A data flow diagram denoting the complete information handling path from output signals of CEMS components to final reports.

(iv) For units monitored by a continuous emission or opacity monitoring system, a schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitoring systems and components, and stacks corresponding to the identification numbers provided in paragraphs (g)(1)(i) and (g)(1)(iii) of this section. The schematic diagram must depict stack height and the height of any monitor locations. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack.

(v) For units monitored by a continuous emission or opacity monitoring system, stack and duct engineering diagrams showing the dimensions and location of fans, turning vanes, air preheaters, monitor components, probes, reference method sampling ports, and other equipment that affects the monitoring system location, performance, or quality control checks.

(h) *Contents of monitoring plan for specific situations.* The following additional information shall be included in the monitoring plan for the specific situations described:

(1) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in appendix D to this part for estimating heat input and/or SO_2 mass emissions, or for each gas-fired or oil-fired peaking unit for which the owner/operator uses the optional protocol in appendix E to this part for estimating NO_X emission rate (using a fuel flowmeter), the designated representative shall include the following additional information for each fuel flowmeter system in the monitoring plan:

(i) *Electronic.* (A) Parameter monitored;

(B) Type of fuel measured, maximum fuel flow rate, units of measure, and basis of maximum fuel flow rate (i.e., upper range value or unit maximum) for each fuel flowmeter;

(C) Test method used to check the accuracy of each fuel flowmeter;

(D) Monitoring system identification code;

(E) The method used to demonstrate that the unit qualifies for monthly GCV sampling or for daily or annual fuel sampling for sulfur content, as applicable; and

(F) Activation date/hour and (if applicable) inactivation date/hour for the fuel flowmeter system;

(ii) *Hardcopy.* (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines, the fuel flowmeter(s), and the stack(s). The schematic diagram must depict the installation location of each fuel flowmeter and the fuel sampling location(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;

(B) For units using the optional default SO_2 emission rate for ''pipeline natural gas'' or ''natural gas'' in appendix D to this part, the information on the sulfur content of the gaseous fuel used to demonstrate compliance with either section 2.3.1.4 or 2.3.2.4 of appendix D to this part;

(C) For units using the 720 hour test under 2.3.6 of Appendix D of this part to determine the required sulfur sampling requirements, report the procedures and results of the test; and

(D) For units using the 720 hour test under 2.3.5 of Appendix D of this part to determine the appropriate fuel GCV sampling frequency, report the procedures used and the results of the test.

(2) For each gas-fired peaking unit and oil-fired peaking unit for which the owner or operator uses the optional procedures in appendix E to this part for estimating NO_X emission rate, the designated representative shall include in the monitoring plan:

(i) *Electronic.* Unit operating and capacity factor information demonstrating that the unit qualifies as a peaking unit, as defined in § 72.2 of this chapter for the current calendar year or ozone season, including: capacity factor data for three calendar years (or ozone seasons) as specified in the definition of peaking unit in § 72.2 of this chapter; the method of qualification used; and an indication of whether the data are actual or projected data.

(ii) *Hardcopy.* (A) A protocol containing methods used to perform the baseline or periodic NO_X emission test; and

(B) Unit operating parameters related to NO_X formation by the unit.

(3) For each gas-fired unit and diesel-fired unit or unit with a wet flue gas pollution control system for which the designated representative claims an opacity monitoring exemption under § 75.14, the designated representative shall include in the hardcopy monitoring plan the information specified under § 75.14(b), (c), or (d), demonstrating that the unit qualifies for the exemption.

(4) For each unit using the low mass emissions excepted methodology under § 75.19 the designated representative shall include the following additional information in the monitoring plan that accompanies the initial certification application:

(i) *Electronic.* For each low mass emissions unit, report the results of the analysis performed to qualify as a low mass emissions unit under § 75.19(c). This report will include either the previous three years actual or projected emissions. The following items should be included:

(A) Current calendar year of application;

(B) Type of qualification;

(C) Years one, two, and three;

(D) Annual and/or ozone season measured, estimated or projected NO_X mass emissions for years one, two, and three;

(E) Annual measured, estimated or projected SO_2 mass emissions (if applicable) for years one, two, and three; and

(F) Annual or ozone season operating hours for years one, two, and three.

(ii) *Hardcopy.* (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines and tanks, any fuel flowmeter(s), and the stack(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;

(B) For units which use the long term fuel flow methodology under § 75.19(c)(3), the designated representative must provide a diagram of the fuel flow to each affected unit or group of units and describe in detail the procedures used to determine the long term fuel flow for a unit or group of units for each fuel combusted by the unit or group of units;

(C) A statement that the unit burns only gaseous fuel(s) and/or fuel oil and a list of the fuels that are burned or a statement that the unit is projected to burn only gaseous fuel(s) and/or fuel oil and a list of the fuels that are projected to be burned;

(D) A statement that the unit meets the applicability requirements in § 75.19(a) and (b); and

(E) Any unit historical actual, estimated and projected emissions data and calculated emissions data demonstrating that the affected unit qualifies as a low mass emissions unit under § 75.19(a) and 75.19(b).

(5) For qualification as a gas-fired unit, as defined in § 72.2 of this part, the designated representative shall include in the monitoring plan, in electronic format, the following: Current calendar year, fuel usage data for three calendar years (or ozone seasons) as specified in the definition of gas-fired in § 72.2 of this part, the method of qualification used, and an indication of whether the data are actual or projected data.

(6) For each monitoring location with a stack flow monitor that is exempt from performing 3-load flow RATAs (peaking units, bypass stacks, or by petition) the designated representative shall include in the monitoring plan an indicator of exemption from 3-load flow RATA using the appropriate exemption code.

■ 23. Section 75.57 is amended by:

■ a. Adding the phrase ‘‘, or mmBtu/hr of thermal output, rounded to the nearest mmBtu/hr’’ after the phrase ‘‘rounded to the nearest 1000 lb/hr’’, in paragraph (b)(3);

■ b. Revising Table 4a in paragraph (c)(4)(iv);

■ c. Removing the word ‘‘hundredth’’ and adding in its place the word ‘‘tenth’’ in paragraph (i)(1)(iv); and

■ d. Removing the words ‘‘, § 75.12(b),’’ from paragraphs (i)(2) and (j)(2).

The revisions read as follows:

§ 75.57 General recordkeeping provisions.

* * * * *

(c) * * *

(4) * * *

(iv) * * *

TABLE 4A.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION

Code	Hourly emissions/flow measurement or estimation method
1	Certified primary emission/flow monitoring system.
2	Certified backup emission/flow monitoring system.
3	Approved alternative monitoring system.
4	Reference method: SO_2: Method 6C. Flow: Method 2 or its allowable alternatives under appendix A to part 60 of this chapter. NO_X: Method 7E. CO_2 or O_2: Method 3A.
5	For units with add-on SO_2 and/or NO_X emission controls: SO_2 concentration or NO_X emission rate estimate from Agency preapproved parametric monitoring method.
6	Average of the hourly SO_2 concentrations, CO_2 concentrations, O_2 concentrations, NO_X concentrations, flow rates, moisture percentages or NO_X emission rates for the hour before and the hour following a missing data period.
7	Initial missing data procedures used. Either: (a) the average of the hourly SO_2 concentration, CO_2 concentration, O_2 concentration, or moisture percentage for the hour before and the hour following a missing data period; or (b) the arithmetic average of all NO_X concentration, NO_X emission rate, or flow rate values at the corresponding load range (or a higher load range), or at the corresponding operational bin (non-load-based units, only); or (c) the arithmetic average of all previous NO_X concentration, NO_X emission rate, or flow rate values (non-load-based units, only).
8	90th percentile hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or 10th percentile hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
9	95th percentile hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or 5th percentile hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
10	Maximum hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or minimum hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
11	Average of hourly flow rates, NO_X concentrations or NO_X emission rates in corresponding load range, for the applicable lookback period. For non-load-based units, report either the average flow rate, NO_X concentration or NO_X emission rate in the applicable lookback period, or the average flow rate or NO_X value at the corresponding operational bin (if operational bins are used).
12	Maximum potential concentration of SO_2, maximum potential concentration of CO_2, maximum potential concentration of NO_X maximum potential flow rate, maximum potential NO_X emission rate, maximum potential moisture percentage, minimum potential O_2 concentration or minimum potential moisture percentage, as determined using § 72.2 of this chapter and section 2.1 of appendix A to this part (moisture missing data algorithm depends on which equations are used for emissions and heat input).
13	Maximum expected concentration of SO_2, maximum expected concentration of NO_X, maximum expected Hg concentration, or maximum controlled NO_X emission rate. (*See* § 75.34(a)(5)).
14	Diluent cap value (if the cap is replacing a CO_2 measurement, use 5.0 percent for boilers and 1.0 percent for turbines; if it is replacing an O_2 measurement, use 14.0 percent for boilers and 19.0 percent for turbines).
15	1.25 times the maximum hourly controlled SO_2 concentration, Hg concentration, NO_X concentration at the corresponding load or operational bin, or NO_X emission rate at the corresponding load or operational bin, in the applicable lookback period (*See* § 75.34(a)(5)).
16	SO_2 concentration value of 2.0 ppm during hours when only ‘‘very low sulfur fuel’’, as defined in § 72.2 of this chapter, is combusted.
17	Like-kind replacement non-redundant backup analyzer.
19	200 percent of the MPC; default high range value.
20	200 percent of the full-scale range setting (full-scale exceedance of high range).
21	Negative hourly CO_2 concentration, SO_2 concentration, NO_X concentration, percent moisture, or NO_X emission rate replaced with zero.
22	Hourly average SO_2 or NO_X concentration, measured by a certified monitor at the control device inlet (units with add-on emission controls only).
23	Maximum potential SO_2 concentration, NO_X concentration, CO_2 concentration, NO_X emission rate or flow rate, or minimum potential O_2 concentration or moisture percentage, for an hour in which flue gases are discharged through an unmonitored bypass stack.
24	Maximum expected NO_X concentration, or maximum controlled NO_X emission rate for an hour in which flue gases are discharged downstream of the NO_X emission controls through an unmonitored bypass stack, and the add-on NO_X emission controls are confirmed to be operating properly.
25	Maximum potential NO_X emission rate (MER). (Use only when a NO_X concentration full-scale exceedance occurs and the diluent monitor is unavailable.)

TABLE 4A.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION—Continued

Code	Hourly emissions/flow measurement or estimation method
26	1.0 mmBtu/hr substituted for Heat Input Rate for an operating hour in which the calculated Heat Input Rate is zero or negative.
32	Hourly Hg concentration determined from analysis of a single trap multiplied by a factor of 1.111 when one of the paired traps is invalidated or damaged (*See* Appendix K, section 8).
33	Hourly Hg concentration determined from the trap resulting in the higher Hg concentration when the relative deviation criterion for the paired traps is not met (*See* Appendix K, section 8).
40	Fuel specific default value (or prorated default value) used for the hour.
54	Other quality assured methodologies approved through petition. These hours are included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.
55	Other substitute data approved through petition. These hours are not included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.

* * * * *

■ 24. Section 75.58 is amended by:
■ a. Revising paragraph (b)(3) introductory text;
■ b. Removing paragraphs (b)(3)(iii) and (b)(3)(iv);
■ c. Removing the word ''and'' from paragraph (c)(1)(xii);
■ d. Removing the period and adding in its place a semicolon and adding the word ''and'' to the end of the paragraph, in paragraph (c)(1)(xiii);
■ e. Adding paragraph (c)(1)(xiv);
■ f. Removing the period and adding in its place a semicolon and adding the word ''and'' to the end of the paragraph, in paragraph (c)(4)(x);
■ g. Adding paragraph (c)(4)(xi);
■ h. Removing the words ''rounded to the nearest hundredth for diesel fuel'' and adding in its place the words ''rounded to either the nearest hundredth, or nearest ten-thousandth for diesel fuels'' in paragraph (c)(5)(ii);
■ i. Removing the word ''and'' after the semicolon in paragraph (d)(1)(ix).
■ j. Removing the period and adding in its place a semicolon and adding the word ''and'' to the end of the paragraph, in paragraph (d)(1)(x);
■ k. Adding paragraph (d)(1)(xi);
■ l. Removing the word ''and'' after the semicolon in paragraph (d)(2)(ix);
■ m. Removing the period and adding in its place a semicolon and adding the word ''and'' to the end of the paragraph, in paragraph (d)(2)(x);
■ n. Adding paragraph (d)(2)(xi);
■ o. Revising paragraph (f)(1)(iii);
■ p. Removing the word ''and'' at the end of paragraph (f)(1)(xi);
■ q. Removing the period and adding in its place a semicolon at the end of paragraph (f)(1)(xii);
■ r. Adding paragraphs (f)(1)(xiii) and (f)(1)(xiv); and
■ s. Removing the word ''Component'' and adding in its place the word ''Monitoring'', in paragraph (f)(2)(x).

The revisions and additions read as follows:

§ 75.58 General recordkeeping provisions for specific situations.

* * * * *

(b) * * *

(3) Except as otherwise provided in § 75.34(d), for units with add-on SO_2 or NO_X emission controls following the provisions of § 75.34(a)(1), (a)(2), (a)(3) or (a)(5), and for units with add-on Hg emission controls, the owner or operator shall record:

* * * * *

(c) * * *

(1) * * *

(xiv) Heat input formula ID and SO_2 Formula ID (required beginning January 1, 2009).

* * * * *

(4) * * *

(xi) Heat input formula ID and SO_2 Formula ID (required beginning January 1, 2009).

* * * * *

(d) * * *

(1) * * *

(xi) Heat input rate formula ID (required beginning January 1, 2009).

(2) * * *

(xi) Heat input rate formula ID (required beginning January 1, 2009).

* * * * *

(f) * * *

(1) * * *

(iii) Fuel type (pipeline natural gas, natural gas, other gaseous fuel, residual oil, or diesel fuel). If more than one type of fuel is combusted in the hour, either:

(A) Indicate the fuel type which results in the highest emission factors for NO_X (this option is in effect through December 31, 2008); or

(B) Indicate the fuel type resulting in the highest emission factor for each parameter (SO_2, NO_X emission rate, and CO_2) separately (this option is required on and after January 1, 2009);

* * * * *

(xiii) Base or peak load indicator (as applicable); and

(xiv) Multiple fuel flag.

* * * * *

■ 25. Section 75.59 is amended by:
■ a. Adding the phrase ''(on and after January 1, 2009, only the component identification code is required)'' after the word ''code'', in paragraph (a)(1)(i);
■ b. Revising paragraph (a)(1)(viii);
■ c. Removing the phrase ''For the qualifying test for off-line calibration, the owner or operator shall indicate'' and adding in its place the phrase ''Indication of'', in paragraph (a)(1)(xi);
■ d. Adding the phrase ''(after January 1, 2009, only the component identification code is required)'' after the word ''code'', in paragraph (a)(2)(i);
■ e. Adding the phrase ''(on and after January 1, 2009, only the component identification code is required)'' after the word ''code'', in paragraph (a)(3)(i);
■ f. Adding the phrase ''(only span scale is required on and after January 1, 2009)'' after the word ''scale'', in paragraph (a)(3)(ii);
■ g. Adding the phrase ''(on and after January 1, 2009, only the system identification code is required)'' after the word ''code'', in paragraph (a)(4)(i);
■ h. Removing the word ''and'' after the semicolon at the end of paragraph (a)(4)(vi)(L);
■ i. Removing the period and adding in its place a semicolon and adding the word ''and'' at the end of paragraph (a)(4)(vi)(M);
■ j. Adding paragraph (a)(4)(vi)(N);
■ k. Removing the word ''and'' after the semicolon, at the end of paragraph (a)(4)(vii)(K);
■ l. Removing the period and adding in its place a semicolon and adding the word ''and'' at the end of paragraph (a)(4)(vii)(L);
■ m. Adding paragraph (a)(4)(vii)(M);
■ n. Revising paragraph (a)(6) introductory text;
■ o. Adding the phrase ''(on and after January 1, 2009, only the component identification code is required)'' after the word ''code'', in paragraph (a)(6)(i);
■ p. Removing the phrase ''Cycle time result for the entire system'' and adding in its place the phrase ''Total cycle time'', in paragraph (a)(6)(ix);
■ q. Revising the heading of reserved paragraph (a)(7)(viii);
■ r. Adding paragraphs (a)(7)(ix) and (a)(7)(x);
■ s. Revising paragraph (a)(8);

■ t. Removing and reserving paragraph (a)(12)(iii);
■ u. Removing the number ''(2)'' from the paragraph identifier ''§ 75.64(a)(2)'' in the second sentence of paragraph (a)(13);
■ v. Adding the phrase ''(on and after January 1, 2009, only the component identification code is required)'' after the word ''tested'', in paragraphs (b)(1)(ii) and (b)(2)(i);
■ w. Adding the phrase ''(on and after January 1, 2009, only the monitoring system identification code is required)'' after the word ''code'', in paragraph (b)(4)(i)(A);
■ x. Removing the word ''and'' after the semicolon at the end of paragraph (b)(4)(i)(H);
■ y. Removing the period and adding in its place a semicolon and adding the word ''and'' at the end of paragraph (b)(4)(i)(I);
■ z. Adding paragraph (b)(4)(i)(J);
■ aa. Revising paragraphs (b)(4)(ii)(A), (b)(4)(ii)(B), and (b)(4)(ii)(F);
■ bb. Removing the word ''and'' after the semicolon at the end of paragraph (b)(4)(ii)(L);
■ cc. Removing the period and adding in its place a semicolon and adding the word ''and'' at the end of paragraph (b)(4)(ii)(M);
■ dd. Adding paragraph (b)(4)(ii)(N);
■ ee. Adding the phrase ''(on and after January 1, 2009, component identification codes shall be reported in addition to the monitoring system identification code)'' after the second occurrence of the word ''system'' in paragraphs (b)(5)(i)(B), (b)(5)(ii)(B), and (b)(5)(iii)(B);
■ ff. Adding the phrase ''This requirement remains in effect through December 31, 2008'' after the word ''run;'', in paragraph (b)(5)(i)(H);
■ gg. Adding the phrase ''(as applicable). This requirement remains in effect through December 31, 2008'' after the word ''level'', in paragraph (b)(5)(iv)(A);
■ hh. Removing the word ''and'' after the semicolon at the end of paragraph (b)(5)(iv)(G);
■ ii. Removing the period and adding in its place a semicolon and adding the word ''and'' at the end of paragraph (b)(5)(iv)(H);
■ jj. Adding paragraph (b)(5)(iv)(I);
■ kk. Removing the word ''and'' after the semicolon at the end of paragraph (d)(1)(xi);
■ ll. Removing the period and adding in its place a semicolon and adding the word ''and'' at the end of paragraph (d)(1)(xii);
■ mm. Adding paragraph (d)(1)(xiii);
■ nn. Removing the phrase '', multiplied by 1.15, if appropriate'' from paragraph (d)(2)(iii);
■ oo. Removing the word ''and'' after the semicolon at the end of paragraph (d)(2)(iv);
■ pp. Removing the period and adding in its place a semicolon at the end of paragraph (d)(2)(v); and
■ qq. Adding paragraphs (d)(2)(vi), (d)(2)(vii), (e) and (f).

The revisions and additions read as follows:

§ 75.59 Certification, quality, assurance, and quality control record provisions.

* * * * *

(a) * * *

(1) * * *

(viii) For 7-day calibration error tests, a test number and reason for test;

* * * * *

(4) * * *

(vi) * * *

(N) Test number.

(vii) * * *

(M) An indicator (''flag'') if separate reference ratios are calculated for each multiple stack.

* * * * *

(6) For each SO_2, NO_X, Hg, or CO_2 pollutant concentration monitor, each component of a NO_X-diluent continuous emission monitoring system, and each CO_2 or O_2 monitor used to determine heat input, the owner or operator shall record the following information for the cycle time test:

* * * * *

(7) * * *

(viii) Data elements for Methods 30A and 30B. [Reserved]

(ix) For a unit with a flow monitor installed on a rectangular stack or duct, if a site-specific default or measured wall effects adjustment factor (WAF) is used to correct the stack gas volumetric flow rate data to account for velocity decay near the stack or duct wall, the owner or operator shall keep records of the following for each flow RATA performed with EPA Method 2 in appendices A–1 and A–2 to part 60 of this chapter, subsequent to the WAF determination:

(A) Monitoring system ID;

(B) Test number;

(C) Operating level;

(D) RATA end date and time;

(E) Number of Method 1 traverse points; and

(F) Wall effects adjustment factor (WAF), to the nearest 0.0001.

(x) For each RATA run using Method 29 in appendix A–8 to part 60 of this chapter to determine Hg concentration:

(A) Percent CO_2 and O_2 in the stack gas, dry basis;

(B) Moisture content of the stack gas (percent H_2O);

(C) Average stack gas temperature (°F);

(D) Dry gas volume metered (dscm);

(E) Percent isokinetic;

(F) Particulate Hg collected in the front half of the sampling train, corrected for the front-half blank value (μg); and

(G) Total vapor phase Hg collected in the back half of the sampling train, corrected for the back-half blank value (μg).

(8) For each certified continuous emission monitoring system, continuous opacity monitoring system, excepted monitoring system, or alternative monitoring system, the date and description of each event which requires certification, recertification, or certain diagnostic testing of the system and the date and type of each test performed. If the conditional data validation procedures of § 75.20(b)(3) are to be used to validate and report data prior to the completion of the required certification, recertification, or diagnostic testing, the date and hour of the probationary calibration error test shall be reported to mark the beginning of conditional data validation.

* * * * *

(b) * * *

(4) * * *

(i) * * *

(J) Test number.

(ii) * * *

(A) Completion date and hour of most recent primary element inspection or test number of the most recent primary element inspection (as applicable); (on and after January 1, 2009, the test number of the most recent primary element inspection is required in lieu of the completion date and hour for the most recent primary element inspection);

(B) Completion date and hour of most recent flow meter of transmitter accuracy test or test number of the most recent flowmeter or transmitter accuracy test (as applicable); (on and after January 1, 2009, the test number of the most recent flowmeter or transmitter accuracy test is required in lieu of the completion date and hour for the most recent flowmeter or transmitter accuracy test);

* * * * *

(F) Average load, in megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output;

* * * * *

(N) Monitoring system identification code.

* * * * *

(5) * * *

(iv) * * *

(I) Component identification code (required on and after January 1, 2009).

* * * * *

(d) * * *

(1) * * *

(xiii) An indicator (''flag'') if the run is used to calculate the highest 3-run average NO_X emission rate at any load level.

(2) * * *

(vi) Indicator of whether the testing was done at base load, peak load or both (if appropriate); and

(vii) The default NO_X emission rate for peak load hours (if applicable).

* * * * *

(e) *Excepted monitoring for Hg low mass emission units under § 75.81(b).* For qualifying coal-fired units using the alternative low mass emission methodology under § 75.81(b), the owner or operator shall record the data elements described in § 75.59(a)(7)(vii), § 75.59(a)(7)(viii), or § 75.59(a)(7)(x), as applicable, for each run of each Hg emission test and re-test required under § 75.81(c)(1) or § 75.81(d)(4)(iii).

(f) *DAHS Verification.* For each DAHS (missing data and formula) verification that is required for initial certification, recertification, or for certain diagnostic testing of a monitoring system, record the date and hour that the DAHS verification is successfully completed. (This requirement only applies to units that report monitoring plan data in accordance with § 75.53(g) and (h).)

* * * * *

■ 26. Section 75.60 is amended by adding paragraph (b)(8) to read as follows:

§ 75.60 General provisions.

* * * * *

(b) * * *

(8) *Routine retest reports for Hg low mass emissions units.* If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report for a semiannual or annual retest required under § 75.81(d)(4)(iii) for a Hg low mass emissions unit, within 45 days after completing the test or within 15 days of receiving the request, whichever is later. The designated representative shall report, at a minimum, the following hardcopy information to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report: a summary of the test results; the raw reference method data for each test run; the raw data and results of all pretest, post-test, and post-run quality-assurance checks of the reference method; the raw data and results of moisture measurements made during the test runs (if applicable); diagrams illustrating the test and sample point locations; a copy of the test protocol used; calibration certificates for the gas standards or standard solutions used in the testing; laboratory calibrations of the source sampling equipment; and the names of the key personnel involved in the test program, including test team members, plant contact persons, agency representatives and test observers.

* * * * *

■ 27. Section 75.61 is amended by:

■ a. Revising the first sentence of paragraph (a)(1) introductory text;

■ b. Revising paragraph (a)(3);

■ c. Revising the first sentence of paragraph (a)(5) introductory text; and

■ d. Adding paragraphs (a)(7) and (a)(8)

The revisions and additions read as follows:

§ 75.61 Notifications.

(a) * * *

(1) * * * The owner or operator or designated representative for an affected unit shall submit written notification of initial certification tests and revised test dates as specified in § 75.20 for continuous emission monitoring systems, for the excepted Hg monitoring methodology under § 75.81(b), for alternative monitoring systems under subpart E of this part, or for excepted monitoring systems under appendix E to this part, except as provided in paragraphs (a)(1)(iii), (a)(1)(iv) and (a)(4) of this section. * * *

* * * * *

(3) *Unit shutdown and recommencement of commercial operation.* For an affected unit that will be shut down on the relevant compliance date specified in § 75.4 or in a State or Federal pollutant mass emissions reduction program that adopts the monitoring and reporting requirements of this part, if the owner or operator is relying on the provisions in § 75.4(d) to postpone certification testing, the designated representative for the unit shall submit notification of unit shutdown and recommencement of commercial operation as follows:

(i) For planned unit shutdowns (e.g., extended maintenance outages), written notification of the planned shutdown date shall be provided at least 21 days prior to the applicable compliance date, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual shutdown date or the actual date of recommencement of commercial operation differs from the planned date, written notice of the actual date shall be submitted no later than 7 days following the actual date of shutdown or of recommencement of commercial operation, as applicable;

(ii) For unplanned unit shutdowns (e.g., forced outages), written notification of the actual shutdown date shall be provided no more than 7 days after the shutdown, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual date of recommencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of recommencement of commercial operation.

* * * * *

(5) * * * The owner or operator or designated representative of an affected unit shall submit written notice of the date of periodic relative accuracy testing performed under section 2.3.1 of appendix B to this part, of periodic retesting performed under section 2.2 of appendix E to this part, of periodic retesting of low mass emissions units performed under § 75.19(c)(1)(iv)(D), and of periodic retesting of Hg low mass emissions units performed under § 75.81(d)(4)(iii), no later than 21 days prior to the first scheduled day of testing. * * *

(7) *Long-term cold storage and recommencement of commercial operation.* The designated representative for an affected unit that is placed into long-term cold storage that is relying on the provisions in § 75.4(d) or § 75.64(a), either to postpone certification testing or to discontinue the submittal of quarterly reports during the period of long-term cold storage, shall provide written notification of long-term cold storage status and recommencement of commercial operation as follows:

(i) Whenever an affected unit has been placed into long-term cold storage, written notification of the date and hour that the unit was shutdown and a statement from the designated representative stating that the shutdown is expected to last for at least two years from that date, in accordance with the definition for long-term cold storage of a unit as provided in § 72.2 of this chapter.

(ii) Whenever an affected unit that has been placed into long-term cold storage is expected to resume operation, written notification shall be submitted 45 calendar days prior to the planned date of recommencement of commercial operation. If the actual date of

recommencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of recommencement of commercial operation.

(8) *Certification deadline date for new or newly affected units.* The designated representative of a new or newly affected unit shall provide notification of the date on which the relevant deadline for initial certification is reached, either as provided in § 75.4(b) or § 75.4(c), or as specified in a State or Federal SO_2, NO_X, or Hg mass emission reduction program that incorporates by reference, or otherwise adopts, the monitoring, recordkeeping, and reporting requirements of subpart F, G, H, or I of this part. The notification shall be submitted no later than 7 calendar days after the applicable certification deadline is reached.

* * * * *

■ 28. Section 75.62 is amended by:
■ a. Revising paragraph (a)(1); and
■ b. Removing the number ''45'' and adding in its place the number ''21'' before the phrase ''days prior'', in paragraph (a)(2).

The revisions read as follows:

§ 75.62 Monitoring plan submittals.

(a) * * *

(1) *Electronic.* Using the format specified in paragraph (c) of this section, the designated representative for an affected unit shall submit a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (a)(2) of this section) to the Administrator as follows: no later than 21 days prior to the initial certification tests; at the time of each certification or recertification application submission; and (prior to or concurrent with) the submittal of the electronic quarterly report for a reporting quarter where an update of the electronic monitoring plan information is required, either under § 75.53(b) or elsewhere in this part.

* * * * *

■ 29. Section 75.63 is amended by:
■ a. Removing the phrase ''and a hardcopy certification application form (EPA form 7610–14)'' from paragraph (a)(1)(i)(A);
■ b. Revising paragraph (a)(1)(ii)(A);
■ c. Adding the phrase ''or § 75.53(h)(4)(ii) (as applicable)'' after the identifier ''§ 75.53(f)(5)(ii)'', in paragraph (a)(1)(ii)(B);
■ d. Removing the phrase ''and a hardcopy certification application form (EPA form 7610–14)'' after the word ''section'', in paragraph (a)(2)(i);
■ e. Revising paragraph (a)(2)(iii);
■ f. Removing and reserving paragraph (b)(2)(iii);
■ g. Revising paragraph (b)(2)(iv).

The revisions read as follows:

§ 75.63 Initial certification or recertification application.

(a) * * *

(1) * * *

(ii) * * *

(A) To the Administrator, the electronic low mass emission qualification information required by § 75.53(f)(5)(i) or § 75.53(h)(4)(i) (as applicable) and paragraph (b)(1)(i) of this section; and

* * * * *

(2) * * *

(iii) Notwithstanding the requirements of paragraphs (a)(2)(i) and (a)(2)(ii) of this section, for an event for which the Administrator determines that only diagnostic tests (*see* § 75.20(b)) are required rather than recertification testing, no hardcopy submittal is required; however, the results of all diagnostic test(s) shall be submitted prior to or concurrent with the electronic quarterly report required under § 75.64. Notwithstanding the requirement of § 75.59(e), for DAHS (missing data and formula) verifications, no hardcopy submittal is required; the owner or operator shall keep these test results on-site in a format suitable for inspection.

* * * * *

(b) * * *

(2) * * *

(iv) Designated representative signature certifying the accuracy of the submission.

* * * * *

■ 30. Section 75.64 is amended by:
■ a. Revising paragraph (a) introductory text;
■ b. Redesignate paragraph (a)(2)(xiv) as paragraph (a)(2)(xiii);
■ c. Revise newly designated paragraph (a)(2)(xiii);
■ d. Removing paragraph (a)(8);
■ e. Redesignating paragraphs (a)(9) through (a)(11) as paragraphs (a)(13) through (a)(15), and redesignating paragraphs (a)(3) through (a)(7) as paragraphs (a)(8) through (a)(12);
■ f. Adding new paragraphs (a)(3) through (a)(7); and
■ g. Removing the citation ''§ 75.59'', and adding in its place ''§ 75.58(f)(2)'' at the end of newly designated paragraph (a)(14).

The revisions and additions read as follows:

§ 75.64 Quarterly reports.

(a) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in paragraphs (a), (b), and (c) of this section to the Administrator quarterly, beginning with the data from the earlier of the calendar quarter corresponding to the date of provisional certification or the calendar quarter corresponding to the relevant deadline for initial certification in § 75.4(a), (b), or (c). The initial quarterly report shall contain hourly data beginning with the hour of provisional certification or the hour corresponding to the relevant certification deadline, whichever is earlier. For an affected unit subject to § 75.4(d) that is shutdown on the relevant compliance date in § 75.4(a) or has been placed in long-term cold storage (as defined in § 72.2 of this chapter), quarterly reports are not required. In such cases, the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences commercial operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced commercial operation of the unit). For units placed into long-term cold storage during a reporting quarter, the exemption from submitting quarterly reports begins with the calendar quarter following the date that the unit is placed into long-term cold storage. For any provisionally-certified monitoring system, § 75.20(a)(3) shall apply for initial certifications, and § 75.20(b)(5) shall apply for recertifications. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Prior to January 1, 2008, each electronic report shall include for each affected unit (or group of units using a common stack), the information provided in paragraphs (a)(1), (a)(2), and (a)(8) through (a)(15) of this section. During the time period of January 1, 2008 to January 1, 2009, each electronic report shall include, either the information provided in paragraphs (a)(1), (a)(2), and (a)(8) through (a)(15) of this section or the information provided in paragraphs (a)(3) through (a)(15) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a)(3) through (a)(15) of this section only. Each electronic report shall also include the date of report generation.

* * * * *

(2) * * *

(xiii) Supplementary RATA information required under § 75.59(a)(7), except that:

(A) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T)

and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments;

(B) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(C) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(D) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

(3) Facility identification information, including:

(i) Facility/ORISPL number;

(ii) Calendar quarter and year for the data contained in the report; and

(iii) Version of the electronic data reporting format used for the report.

(4) In accordance with § 75.62(a)(1), if any monitoring plan information required in § 75.53 requires an update, either under § 75.53(b) or elsewhere in this part, submission of the electronic monitoring plan update shall be completed prior to or concurrent with the submittal of the quarterly electronic data report for the appropriate quarter in which the update is required.

(5) Except for the daily calibration error test data, daily interference check, and off-line calibration demonstration information required in § 75.59(a)(1) and (2), which must always be submitted with the quarterly report, the certification, quality assurance, and quality control information required in § 75.59 shall either be submitted prior to or concurrent with the submittal of the relevant quarterly electronic data report.

(6) The information and hourly data required in §§ 75.57 through 75.59, and daily calibration error test data, daily interference check, and off-line calibration demonstration information required in § 75.59(a)(1) and (2).

(7) Notwithstanding the requirements of paragraphs (a)(4) through (a)(6) of this section, the following information is excluded from electronic reporting:

(i) Descriptions of adjustments, corrective action, and maintenance;

(ii) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);

(iii) Opacity data listed in § 75.57(f), and in § 75.59(a)(8);

(iv) For units with SO_2 or NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in § 75.58(b)(3);

(v) Information required by § 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;

(vi) Hardcopy monitoring plan information required by § 75.53 and hardcopy test data and results required by § 75.59;

(vii) Records of flow monitor and moisture monitoring system polynomial equations, coefficients, or ''K'' factors required by § 75.59(a)(5)(vi) or § 75.59(a)(5)(vii);

(viii) Daily fuel sampling information required by § 75.58(c)(3)(i) for units using assumed values under appendix D of this part;

(ix) Information required by §§ 75.59(b)(1)(vi), (vii), (viii), (ix), and (xiii), and (b)(2)(iii) and (iv) concerning fuel flowmeter accuracy tests and transmitter/transducer accuracy tests;

(x) Stratification test results required as part of the RATA supplementary records under § 75.59(a)(7);

(xi) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to problems unrelated to monitor performance; and

(xii) Supplementary RATA information required under § 75.59(a)(7)(i) through § 75.59(a)(7)(v), except that:

(A) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments;

(B) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(C) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(D) The data under § 75.59(a)(7)(vii)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

* * * * *

§ 75.66 [Amended]

■ 31. Section 75.66 is amended by removing and reserving paragraph (f).

■ 32. Section 75.71 is amended by:

■ a. Revising the section heading;

■ b. In paragraph (a)(1), by removing the second occurrence of the phrase ''CO_2 diluent gas monitor'' and adding in its place the phrase ''CO_2 diluent gas monitoring system'';

■ c. Removing the phrase ''O_2 or CO_2 diluent gas monitor'' and adding in its place the phrase ''O_2 or CO_2 monitoring system'', in paragraph (a)(2); and

■ d. Revising paragraph (e).

The revision reads as follows:

§ 75.71 Specific provisions for monitoring NO_X and heat input for the purpose of calculating NO_X mass emissions.

* * * * *

(e) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (c) and (d) of this section, for an affected unit using the low mass emissions (LME) unit under § 75.19 to estimate hourly NO_X emission rate, heat input and NO_X mass emissions, the owner or operator shall calculate the ozone season NO_X mass emissions by summing all of the estimated hourly NO_X mass emissions in the ozone season, as determined under § 75.19 (c)(4)(ii)(A), and dividing this sum by 2000 lb/ton.

* * * * *

■ 33. Section 75.72 is amended by:

■ a. Revising the section heading and the introductory text;

■ b. Revising paragraph (c)(3); and

■ c. Removing and reserving paragraph (f).

The revisions read as follows:

§ 75.72 Determination of NO_X mass emissions for common stack and multiple stack configurations.

The owner or operator of an affected unit shall either: calculate hourly NO_X mass emissions (in lbs) by multiplying the hourly NO_X emission rate (in lbs/

mmBtu) by the hourly heat input rate (in mmBtu/hr) and the unit or stack operating time (as defined in § 72.2), or, as provided in paragraph (e) of this section, calculate hourly NO_X mass emissions from the hourly NO_X concentration (in ppm) and the hourly stack flow rate (in scfh). Only one methodology for determining NO_X mass emissions shall be identified in the monitoring plan for each monitoring location at any given time. The owner or operator shall also calculate quarterly and cumulative year-to-date NO_X mass emissions and cumulative NO_X mass emissions for the ozone season (in tons) by summing the hourly NO_X mass emissions according to the procedures in section 8 of appendix F to this part.

* * * * *

(c) * * *

(3) Install, certify, operate, and maintain a NO_X-diluent CEMS and a flow monitoring system only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under § 75.53, since only the main stack is monitored. For each unit operating hour in which the bypass stack is used and the emissions are either uncontrolled (or the add-on controls are not documented to be operating properly), report NO_X mass emissions as follows. If the unit heat input is determined using a flow monitor and a diluent monitor, report NO_X mass emissions using the maximum potential NO_X emission rate, the maximum potential flow rate, and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable). The maximum potential NO_X emission rate may be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). If the unit heat input is determined using a fuel flowmeter, in accordance with appendix D to this part, report NO_X mass emissions as the product of the maximum potential NO_X emission rate and the actual measured hourly heat input rate. Alternatively, for a unit with NO_X add-on emission controls, for each unit operating hour in which the bypass stack is used but the add-on NO_X emission controls are not bypassed, the owner or operator may report the maximum controlled NO_X emission rate (MCR) instead of the maximum potential NO_X emission rate provided that the add-on controls are documented to be operating properly, as described in the quality assurance/quality control program for the unit, required by section 1 in appendix B of this part. To provide the necessary documentation, the owner or operator shall record parametric data to verify the proper operation of the NO_X add-on emission controls as described in § 75.34(d). Furthermore, the owner or operator shall calculate the MCR using the procedure described in section 2.1.2.1(b) of appendix A to this part by replacing the words ''maximum potential NO_X emission rate (MER)'' with the words ''maximum controlled NO_X emission rate (MCR)'' and by using the NO_X MEC in the calculations instead of the NO_X MPC.

* * * * *

(f) [Reserved]

* * * * *

■ 34. Section 75.73 is amended by:

■ a. Revising paragraph (c)(3);

■ b. Removing the number ''45'' and adding in its place the number ''21'' in paragraphs (e)(1) and (e)(2);

■ c. Revising paragraph (f)(1) introductory text;

■ d. Removing the phrase ''paragraph (a)'' and adding in its place the phrase ''paragraphs (a) and (b)'' in paragraph (f)(1)(ii) introductory text; and

■ e. Revising paragraph (f)(1)(ii)(K).

The revisions read as follows:

§ 75.73 Recordkeeping and reporting.

* * * * *

(c) * * *

(3) *Contents of the monitoring plan for units not subject to an Acid Rain emissions limitation.* Prior to January 1, 2009, each monitoring plan shall contain the information in § 75.53(e)(1) or § 75.53(g)(1) in electronic format and the information in § 75.53(e)(2) or § 75.53(g)(2) in hardcopy format. On and after January 1, 2009, each monitoring plan shall contain the information in § 75.53(g)(1) in electronic format and the information in § 75.53(g)(2) in hardcopy format, only. In addition, to the extent applicable, prior to January 1, 2009, each monitoring plan shall contain the information in § 75.53(f)(1)(i), (f)(2)(i), and (f)(4) or § 75.53(h)(1)(i), and (h)(2)(i) in electronic format and the information in § 75.53(f)(1)(ii) and (f)(2)(ii) or § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format. On and after January 1, 2009, each monitoring plan shall contain the information in § 75.53(h)(1)(i), and (h)(2)(i) in electronic format and the information in § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format, only. For units using the low mass emissions excepted methodology under § 75.19, prior to January 1, 2009, the monitoring plan shall include the additional information in § 75.53(f)(5)(i) and (f)(5)(ii) or § 75.53(h)(4)(i) and (h)(4)(ii). On and after January 1, 2009, for units using the low mass emissions excepted methodology under § 75.19 the monitoring plan shall include the additional information in § 75.53(h)(4)(i) and (h)(4)(ii), only. Prior to January 1, 2008, the monitoring plan shall also identify, in electronic format, the reporting schedule for the affected unit (ozone season or quarterly), and the beginning and end dates for the reporting schedule. The monitoring plan also shall include a seasonal controls indicator, and an ozone season fuel-switching flag.

* * * * *

(f) * * *

(1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly, unless the unit has been placed in long-term cold storage (as defined in § 72.2 of this chapter). For units placed into long-term cold storage during a reporting quarter, the exemption from submitting quarterly reports begins with the calendar quarter following the date that the unit is placed into long-term cold storage. In such cases, the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced operation of the unit). Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Except as otherwise provided in § 75.64(a)(4) and (a)(5), each electronic report shall include the information provided in paragraphs (f)(1)(i) through (1)(vi) of this section, and shall also include the date of report generation. Prior to January 1, 2009, each report shall include the facility information provided in paragraphs (f)(1)(i)(A) and (B) of this section, for each affected unit or group of units monitored at a common stack. On and after January 1, 2009, only the facility identification information provided in paragraph (f)(1)(i)(A) of this section is required.

* * * * *

(ii) * * *

(K) Supplementary RATA information required under § 75.59(a)(7), except that:

(*1*) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method

2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments;

(*2*) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(*3*) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(*4*) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

* * * * *

■ 35. Section 75.74 is amended by:

■ a. Removing the phrase ''In the time period prior to the start of the current ozone season (i.e., in the period extending from October 1 of the previous calendar year through April 30 of the current calendar year), the'', and adding in its place the word ''The'', in paragraph (c)(2) introductory text;

■ b. Adding the words ''in the second calendar quarter no later than April 30'' to the end of paragraph (c)(2)(i) introductory text;

■ c. Removing the phrase ''of the current calendar year'' from the first sentence, and removing the last sentence of paragraph (c)(2)(i)(C);

■ d. Revising paragraph (c)(2)(i)(D);

■ e. Adding the words ''in the first or second calendar quarter, but no later than April 30'' to the end of the first sentence, and by removing the second sentence of paragraph (c)(2)(ii) introductory text;

■ f. Removing the words ''of the current calendar year'' from paragraph (c)(2)(ii)(E);

■ g. Revising paragraph (c)(2)(ii)(F);

■ h. Removing paragraphs (c)(2)(ii)(G) and (c)(2)(ii)(H);

■ i. Revising paragraph (c)(3)(ii);

■ j. Removing and reserving paragraphs (c)(3)(vi) through (viii);

■ k. Removing all occurrences of the words ''§ 75.31, § 75.33, or § 75.37'' and adding in their place the words ''§§ 75.31 through 75.37'' in paragraphs (c)(3)(xi), (c)(3)(xii)(A), and (c)(3)(xii)(B);

■ l. Revising paragraph (c)(6)(iii);

■ m. Removing the words ''October 1 of the previous calendar year'' and adding in its place the words ''January 1'' in paragraph (c)(6)(v);

■ n. Revising paragraph (c)(7)(iii)(L);

■ o. Revising paragraph (c)(8)(ii); and

■ p. Revising paragraph (c)(11).

The revisions read as follows:

§ 75.74 Annual and ozone season monitoring and reporting requirements.

* * * * *

(c) * * *

(2) * * *

(i) * * *

(D) If the linearity check is not completed by April 30, data validation shall be determined in accordance with paragraph (c)(3)(ii)(E) of this section.

(ii) * * *

(F) *Data Validation.* For each RATA that is performed by April 30, data validation shall be done according to sections 2.3.2(a)–(j) of appendix B to this part. However, if a required RATA is not completed by April 30, data from the monitoring system shall be invalid, beginning with the first unit operating hour on or after May 1. The owner or operator shall continue to invalidate all data from the CEMS until either:

(*1*) The required RATA of the CEMS has been performed and passed; or

(*2*) A probationary calibration error test of the CEMS is passed in accordance with § 75.20(b)(3)(ii). Once the probationary calibration error test has been passed, the owner or operator shall perform the required RATA in accordance with the conditional data validation provisions and within the 720 unit or stack operating hour time frame specified in § 75.20(b)(3) (subject to the restrictions in paragraph (c)(3)(xii) of this section), and the term ''quality assurance'' shall apply instead of the term ''recertification.'' However, in lieu of the provisions in § 75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(3) * * *

(ii) For each gas monitor required by this subpart, linearity checks shall be performed in the second and third calendar quarters, as follows:

(A) For the second calendar quarter, the pre-ozone season linearity check required under paragraph (c)(2)(i) of this section shall be performed by April 30.

(B) For the third calendar quarter, a linearity check shall be performed and passed no later than July 30.

(C) Conduct each linearity check in accordance with the general procedures in section 6.2 of appendix A to this part, except that the data validation procedures in sections 6.2(a) through (f) of appendix A do not apply.

(D) Each linearity check shall be done ''hands-off,'' as described in section 2.2.3(c) of appendix B to this part.

(E) *Data Validation.* For second and third quarter linearity checks performed by the applicable deadline (i.e., April 30 or July 30), data validation shall be done in accordance with sections 2.2.3(a), (b), (c), (e), and (h) of Appendix B to this part. However, if a required linearity check for the second calendar quarter is not completed by April 30, or if a required linearity check for the third calendar quarter is not completed by July 30, data from the monitoring system (or range) shall be invalid, beginning with the first unit operating hour on or after May 1 or July 31, respectively. The owner or operator shall continue to invalidate all data from the CEMS until either:

(*1*) The required linearity check of the CEMS has been performed and passed; or

(*2*) A probationary calibration error test of the CEMS is passed in accordance with § 75.20(b)(3)(ii). Once the probationary calibration error test has been passed, the owner or operator shall perform the required linearity check in accordance with the conditional data validation provisions and within the 168 unit or stack operating hour time frame specified in § 75.20(b)(3) (subject to the restrictions in paragraph (c)(3)(xii) of this section), and the term ''quality assurance'' shall apply instead of the term ''recertification.'' However, in lieu of the provisions in § 75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(F) A pre-season linearity check performed and passed in April satisfies the linearity check requirement for the second quarter.

(G) The third quarter linearity check requirement in paragraph (c)(3)(ii)(B) of this section is waived if:

(*1*) Due to infrequent unit operation, the 168 operating hour conditional data validation period associated with a pre-season linearity check extends into the third quarter; and

(*2*) A linearity check is performed and passed within that conditional data validation period.

* * * * *

(6) * * *

(iii) For the time periods described in paragraphs (c)(2)(i)(C) and (c)(2)(ii)(E) of this section, hourly emission data and the results of all daily calibration error tests and flow monitor interference checks shall be recorded. The owner or operator may opt to report unit operating data, daily calibration error test and flow monitor interference check results, and hourly emission data in the time period from April 1 through April

30. However, only the data recorded in the time period from May 1 through September 30 shall be used for NO_X mass compliance determination;

* * * * *

(7) * * *

(iii) * * *

(L) In § 75.34(a)(3) and (a)(5), the phrases ''720 quality-assured monitor operating hours within the ozone season'' and ''2160 quality-assured monitor operating hours within the ozone season'' apply instead of ''720 quality-assured monitor operating hours'' and ''2160 quality-assured monitor operating hours'', respectively.

(8) * * *

(ii) For units with add-on emission controls, using the missing data options in §§ 75.34(a)(1) through 75.34(a)(5), the range of operating parameters for add-on emission controls (as defined in the quality assurance/quality control program for the unit required by section 1 in appendix B to this part) and information for verifying proper operation of the add-on emission controls during missing data periods, as described in § 75.34(d).

* * * * *

(11) Units may qualify to use the optional NO_X mass emissions estimation protocol for gas-fired and oil-fired peaking units in appendix E to this part on an ozone season basis. In order to be allowed to use this methodology, the unit must meet the definition of ''peaking unit'' in § 72.2 of this chapter, except that the words ''year'', ''calendar year'' and ''calendar years'' in that definition shall be replaced by the words ''ozone season'', ''ozone season'', and ''ozone seasons'', respectively. In addition, in the definition of the term ''capacity factor'' in § 72.2 of this chapter, the word ''annual'' shall be replaced by the words ''ozone season'' and the number ''8,760'' shall be replaced by the number ''3,672''.

§ 75.80 [Amended]

■ 36. Section 75.80(f)(1)(iii) is amended by removing the words ''or § 75.12(b),''.

■ 37. Section 75.81 is amended by:

■ a. Removing the words ''or § 75.12(b)'' and ''or § 75.12,'' from paragraph (a)(3);

■ b. Revising paragraph (a)(4);

■ c. Revising paragraph (c)(1);

■ d. Revising paragraph (c)(2);

■ e. Removing Eq. 1 from paragraph (d)(1);

■ f. Revising paragraph (d)(2);

■ g. Adding paragraph (d)(4)(iv); and

■ h. Revising paragraphs (d)(5) and (e)(1).

The revisions and additions read as follows:

§ 75.81 Monitoring of Hg mass emissions and heat input at the unit level.

* * * * *

(a) * * *

(4) If heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator must meet the general operating requirements for a flow monitoring system and an O_2 or CO_2 monitoring system to measure heat input rate.

* * * * *

(c) * * *

(1) The owner or operator must perform Hg emission testing one year or less before the compliance date in § 75.80(b), to determine the Hg concentration (i.e., total vapor phase Hg) in the effluent.

(i) The testing shall be performed using one of the Hg reference methods listed in § 75.22(a)(7), and shall consist of a minimum of 3 runs at the normal unit operating load, while combusting coal. The coal combusted during the testing shall be representative of the coal that will be combusted at the start of the Hg mass emissions reduction program (preferably from the same source(s) of supply).

(ii) The minimum time per run shall be 1 hour if Method 30A is used. If either Method 29 in appendix A–8 to part 60 of this chapter, ASTM D6784–02 (the Ontario Hydro method) (incorporated by reference under § 75.6 of this part), or Method 30B is used, paired samples are required for each test run and the runs must be long enough to ensure that sufficient Hg is collected to analyze. When Method 29 in appendix A–8 to part 60 of this chapter or the Ontario Hydro method is used, the test results shall be based on the vapor phase Hg collected in the back-half of the sampling trains (i.e., the non-filterable impinger catches). For each Method 29 in appendix A–8 to part 60 of this chapter, Method 30B, or Ontario Hydro method test run, the paired trains must meet the relative deviation (RD) requirement specified in § 75.22(a)(7) or Method 30B, as applicable. If the RD specification is met, the results of the two samples shall be averaged arithmetically.

(iii) If the unit is equipped with flue gas desulfurization or add-on Hg emission controls, the controls must be operating normally during the testing, and, for the purpose of establishing proper operation of the controls, the owner or operator shall record parametric data or SO_2 concentration data in accordance with § 75.58(b)(3)(i).

(iv) If two or more of units of the same type qualify as a group of identical units in accordance with § 75.19(c)(1)(iv)(B), the owner or operator may test a subset of these units in lieu of testing each unit individually. If this option is selected, the number of units required to be tested shall be determined from Table LM–4 in § 75.19. For the purposes of the required retests under paragraph (d)(4) of this section, EPA strongly recommends that (to the extent practicable) the same subset of the units not be tested in two successive retests, and that every effort be made to ensure that each unit in the group of identical units is tested in a timely manner.

(2)(i) Based on the results of the emission testing, Equation 1 of this section shall be used to provide a conservative estimate of the annual Hg mass emissions from the unit:

$$E = N\ K\ C_{Hg}\ Q_{max} \qquad \text{(Eq. 1)}$$

Where:

E = Estimated annual Hg mass emissions from the affected unit, (ounces/year)

K = Units conversion constant, 9.978×10^{-10} oz-scm/μg-scf

N = Either 8,760 (the number of hours in a year) or the maximum number of operating hours per year (if less than 8,760) allowed by the unit's Federally-enforceable operating permit.

C_{Hg} = The highest Hg concentration (μg/scm) from any of the test runs or 0.50 μg/scm, whichever is greater

Q_{max} = Maximum potential flow rate, determined according to section 2.1.4.1 of appendix A to this part, (scfh)

(ii) Equation 1 of this section assumes that the unit operates at its maximum potential flow rate, either year-round or for the maximum number of hours allowed by the operating permit (if unit operation is restricted to less than 8,760 hours per year). If the permit restricts the annual unit heat input but not the number of annual unit operating hours, the owner or operator may divide the allowable annual heat input (mmBtu) by the design rated heat input capacity of the unit (mmBtu/hr) to determine the value of ''N'' in Equation 1. Also, note that if the highest Hg concentration

measured in any test run is less than 0.50 μg/scm, a default value of 0.50 μg/scm must be used in the calculations.

* * * * *

(d) * * *

(2) Following initial certification, the same default Hg concentration value that was used to estimate the unit's annual Hg mass emissions under paragraph (c) of this section shall be reported for each unit operating hour, except as otherwise provided in paragraph (d)(4)(iv) or (d)(6) of this section. The default Hg concentration value shall be updated as appropriate, according to paragraph (d)(5) of this section.

* * * * *

(4) * * *

(iv) An additional retest is required when there is a change in the coal rank of the primary fuel (e.g., when the primary fuel is switched from bituminous coal to lignite). Use ASTM D388–99 (incorporated by reference under § 75.6 of this part) to determine the coal rank. The four principal coal ranks are anthracitic, bituminous, subbituminous, and lignitic. The ranks of anthracite coal refuse (culm) and bituminous coal refuse (gob) shall be anthracitic and bituminous, respectively. The retest shall be performed within 720 unit operating hours of the change.

(5) The default Hg concentration used for reporting under § 75.84 shall be updated after each required retest. This includes retests that are required prior to the compliance date in § 75.80(b). The updated value shall either be the highest Hg concentration measured in any of the test runs or 0.50 μg/scm, whichever is greater. The updated value shall be applied beginning with the first unit operating hour in which Hg emissions data are required to be reported after completion of the retest, except as provided in paragraph (d)(4)(iv) of this section, where the need to retest is triggered by a change in the coal rank of the primary fuel. In that case, apply the updated default Hg concentration beginning with the first unit operating hour in which Hg emissions are required to be reported after the date and hour of the fuel switch.

* * * * *

(e) * * *

(1) The methodology may not be used for reporting Hg mass emissions at a common stack unless all of the units using the common stack are affected units and the units' combined potential to emit does not exceed 464 ounces of Hg per year times the number of units sharing the stack, in accordance with paragraphs (c) and (d) of this section. If the test results demonstrate that the units sharing the common stack qualify as low mass emitters, the default Hg concentration used for reporting Hg mass emissions at the common stack shall either be the highest value obtained in any test run or 0.50 μg/scm, whichever is greater.

(i) The initial emission testing required under paragraph (c) of this section may be performed at the common stack if the following conditions are met. Otherwise, testing of the individual units (or a subset of the units, if identical, as described in paragraph (c)(1)(iv) of this section) is required:

(A) The testing must be done at a combined load corresponding to the designated normal load level (low, mid, or high) for the units sharing the common stack, in accordance with section 6.5.2.1 of appendix A to this part;

(B) All of the units that share the stack must be operating in a normal, stable manner and at typical load levels during the emission testing. The coal combusted in each unit during the testing must be representative of the coal that will be combusted in that unit at the start of the Hg mass emission reduction program (preferably from the same source(s) of supply);

(C) If flue gas desulfurization and/or add-on Hg emission controls are used to reduce level the emissions exiting from the common stack, these emission controls must be operating normally during the emission testing and, for the purpose of establishing proper operation of the controls, the owner or operator shall record parametric data or SO_2 concentration data in accordance with § 75.58(b)(3)(i);

(D) When calculating E, the estimated maximum potential annual Hg mass emissions from the stack, substitute the maximum potential flow rate through the common stack (as defined in the monitoring plan) and the highest concentration from any test run (or 0.50 μg/scm, if greater) into Equation 1;

(E) The calculated value of E shall be divided by the number of units sharing the stack. If the result, when rounded to the nearest ounce, does not exceed 464 ounces, the units qualify to use the low mass emission methodology; and

(F) If the units qualify to use the methodology, the default Hg concentration used for reporting at the common stack shall be the highest value obtained in any test run or 0.50 μg/scm, whichever is greater; or

(ii) The retests required under paragraph (d)(4) of this section may also be done at the common stack. If this testing option is chosen, the testing shall be done at a combined load corresponding to the designated normal load level (low, mid, or high) for the units sharing the common stack, in accordance with section 6.5.2.1 of appendix A to this part. Provided that the required load level is attained and that all of the units sharing the stack are fed from the same on-site coal supply during normal operation, it is not necessary for all of the units sharing the stack to be in operation during a retest. However, if two or more of the units that share the stack are fed from different on-site coal supplies (e.g., one unit burns low-sulfur coal for compliance and the other combusts higher-sulfur coal), then either:

(A) Perform the retest with all units in normal operation; or

(B) If this is not possible, due to circumstances beyond the control of the owner or operator (e.g., a forced unit outage), perform the retest with the available units operating and assess the test results as follows. Use the Hg concentration obtained in the retest for reporting purposes under this part if the concentration is greater than or equal to the value obtained in the most recent test. If the retested value is lower than the Hg concentration from the previous test, continue using the higher value from the previous test for reporting purposes and use that same higher Hg concentration value in Equation 1 to determine the due date for the next retest, as described in paragraph (e)(1)(iii) of this section.

(iii) If testing is done at the common stack, the due date for the next scheduled retest shall be determined as follows:

(A) Substitute the maximum potential flow rate for the common stack (as defined in the monitoring plan) and the highest Hg concentration from any test run (or 0.50 μg/scm, if greater) into Equation 1;

(B) If the value of E obtained from Equation 1, rounded to the nearest ounce, is greater than 144 times the number of units sharing the common stack, but less than or equal to 464 times the number of units sharing the stack, the next retest is due in two QA operating quarters;

(C) If the value of E obtained from Equation 1, rounded to the nearest ounce, is less than or equal to 144 times the number of units sharing the common stack, the next retest is due in four QA operating quarters.

* * * * *

■ 38. Section 75.82 is amended by:

■ a. Adding paragraph (b)(3);

■ b. Removing the word ''or'' at the end of paragraph (c)(2);

■ c. Removing the period at the end of paragraph (c)(3), and adding in its place the phrase ''; or'';
■ d. Adding paragraph (c)(4);
■ e. Removing the word ''or'' at the end of paragraph (d)(1);
■ f. Removing the period at the end of paragraph (d)(2), and adding in its place the phrase ''; or''; and
■ g. Adding paragraph (d)(3).

The revisions and additions read as follows:

§ 75.82 Monitoring of Hg mass emissions and heat input at common and multiple stacks.

* * * * *

(b) * * *

(3) If the monitoring option in paragraph (b)(2) of this section is selected, and if heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator shall either:

(i) Apportion the common stack heat input rate to the individual units according to the procedures in § 75.16(e)(3); or

(ii) Install a flow monitoring system and a diluent gas (O_2 or CO_2) monitoring system in the duct leading from each affected unit to the common stack, and measure the heat input rate in each duct, according to section 5.2 of appendix F to this part.

(c) * * *

(4) If the monitoring option in paragraph (c)(1) or (c)(2) of this section is selected, and if heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator shall:

(i) Use the installed flow and diluent monitors to determine the hourly heat input rate at each stack (mmBtu/hr), according to section 5.2 of appendix F to this part; and

(ii) Calculate the hourly heat input at each stack (in mmBtu) by multiplying the measured stack heat input rate by the corresponding stack operating time; and

(iii) Determine the hourly unit heat input by summing the hourly stack heat input values.

(d) * * *

(3) If the monitoring option in paragraph (d)(1) or (d)(2) of this section is selected, and if heat input is required to be reported under the applicable State or Federal Hg mass emission reduction program that adopts the requirements of this subpart, the owner or operator shall:

(i) Use the installed flow and diluent monitors to determine the hourly heat input rate at each stack or duct (mmBtu/hr), according to section 5.2 of appendix F to this part; and

(ii) Calculate the hourly heat input at each stack or duct (in mmBtu) by multiplying the measured stack (or duct) heat input rate by the corresponding stack (or duct) operating time; and

(iii) Determine the hourly unit heat input by summing the hourly stack (or duct) heat input values.

■ 39. Section 75.84 is amended by:
■ a. Removing ''§ 75.53(e)(1)'' and ''§ 75.53(e)(2)'' and adding in their place ''§ 75.53(g)(1)'' and ''§ 75.53(g)(2)'', in paragraph (c)(3);
■ b. Removing the number ''45'' and adding in its place the number ''21'' in paragraphs (e)(1) and (e)(2);
■ c. Revising paragraph (f)(1) introductory text;
■ d. Removing ''§ 75.64(a)(1)'' and adding in its place ''§ 75.64(a)(3)'' in paragraph (f)(1)(i);
■ e. Removing the phrase ''paragraph (a)'' and adding in its place the phrase ''paragraphs (a) and (b)'' in paragraph (f)(1)(ii) introductory text; and
■ f. Revising paragraph (f)(1)(ii)(I).

The revisions read as follows:

§ 75.84 Recordkeeping and reporting.

* * * * *

(f) * * *

(1) *Electronic submission.* Electronic quarterly reports shall be submitted, beginning with the calendar quarter containing the compliance date in § 75.80(b), unless otherwise specified in the final rule implementing a State or Federal Hg mass emissions reduction program that adopts the requirements of this subpart. The designated representative for an affected unit shall report the data and information in this paragraph (f)(1) and the applicable compliance certification information in paragraph (f)(2) of this section to the Administrator quarterly, except as otherwise provided in § 75.64(a) for units in long-term cold storage. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Except as otherwise provided in § 75.64(a)(4) and (a)(5), each electronic report shall include the date of report generation and the following information for each affected unit or group of units monitored at a common stack:

* * * * *

(ii) * * *

(I) Supplementary RATA information required under § 75.59(a)(7), except that:

(*1*) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (i.e., Method 2F or 2G in appendices A–1 and A–2 to part 60 of this chapter), with or without wall effects adjustments;

(*2*) The applicable data elements under § 75.59(a)(7)(ii)(A) through (T) and under § 75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(*3*) The data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(*4*) The data under § 75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A–1 and A–2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

* * * * *

■ 40. Appendix A to Part 75 is amended by:
■ a. Revising paragraph (c) of section 2.1.1.1;
■ b. Revising paragraph (b)(2) of section 2.1.1.5;
■ c. Revising paragraph (b)(2) of section 2.1.2.5;
■ d. Adding a new fourth sentence after the third sentence of section 2.1.3;
■ e. Revising paragraph (3) of section 3.2;
■ f. Removing the phrase ''continuous emission monitoring system(s)'' and adding in its place the phrase ''monitoring component of a continuous emission monitoring system that is'' in section 3.5;
■ g. Adding the words ''that meet the definition for a NIST Traceable Reference Material (NTRM) provided in § 72.2.'' after the word ''gases'' in section 5.1.3;
■ h. Revising sections 5.1.4 and 5.1.9;
■ i. Redesignating section 6.1 as section 6.1.1 and adding a new heading for 6.1;
■ j. Adding section 6.1.2;
■ k. Revising the second and third sentences and adding a new fourth sentence to section 6.2, introductory text;
■ l. Revising section 6.2(g);
■ m. Adding paragraph (h) to section 6.2;
■ n. Adding a new fourth sentence to section 6.3.1, introductory text;
■ o. Revising the introductory text of section 6.4;

■ p. Revising paragraph (e) in section 6.5;

■ q. Removing the words ''that uses CEMS to account for its emissions and for each unit that uses the optional fuel flow-to-load quality assurance test in section 2.1.7 of appendix D to this part'' from paragraph (a) of section 6.5.2.1;

■ r. Adding the words ''or mmBtu/hr'' after the words ''klb/hr of steam production'', and by adding the words ''or mmBtu/hr of thermal output'' after the words ''thousands of lb/hr of steam load'' in paragraph (a)(1) of section 6.5.2.1;

■ s. Adding the words ''and units using the low mass emissions (LME) excepted methodology under § 75.19'' after the words ''(except for peaking units'' in the second sentence in paragraph (c) of section 6.5.2.1;

■ t. Adding the words ''and LME units'' after the words ''For peaking units'' in the third sentence in paragraph (d)(1) of section 6.5.2.1;

■ u. Revising paragraph (e) of section 6.5.2.1;

■ v. Revising paragraph (c) in section 6.5.6;

■ w. Removing all occurrences of the words ''section 3.2'' and adding in its place the words ''section 8.1.3'' in paragraph (b)(3) of section 6.5.6, paragraph (a) of section 6.5.6.2, and paragraph (a) of section 6.5.6.3;

■ x. Revising section 6.5.10;

■ y. Adding two sentences at the end of section 7.6.1;

■ z. Revising the terms R_{ref} and L_{avg}, in paragraph (a) of section 7.7;

■ aa. Revising the terms $(GHR)_{ref}$ and L_{avg}, in paragraph (c) of section 7.7; and

■ bb. Removing Figure 6 and adding in its place Figures 6a and 6b and revising A through F and adding G at the end of appendix A.

The revisions and additions read as follows:

Appendix A to Part 75—Specifications and Procedures

* * * * *

2. Equipment Specifications

2.1.1.1 Maximum Potential Concentration

* * * * *

(c) When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D3177–02 (Reapproved 2007), Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke; ASTM D4239–02, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods; ASTM D4294–98, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry; ASTM D1552–01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method); ASTM D129–00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method); ASTM D2622–98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, for sulfur content of solid or liquid fuels; ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke; ASTM D240–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter; or ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke (all incorporated by reference under § 75.6 of this part).

* * * * *

2.1.1.5 * * *

(b) * * *

(2) For units with two SO_2 spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the SO_2 concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded follow the procedures in paragraph (b)(1) of this section).

* * * * *

2.1.2.5 * * *

(b) * * *

(2) For units with two NO_X spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and its most recent calibration error test and linearity check have not expired. However, if either of these quality assurance tests has expired and the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the NO_X concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded, follow the procedures in paragraph (b)(1) of this section).

* * * * *

2.1.3 CO_2 and O_2 Monitors

* * * An alternative CO_2 span value below 6.0 percent may be used if an appropriate technical justification is included in the hardcopy monitoring plan.

* * * * *

3.2 * * *

(3) For the linearity check and the 3-level system integrity check of an Hg monitor, which are required, respectively, under § 75.20(c)(1)(ii) and (c)(1)(vi), the measurement error shall not exceed 10.0 percent of the reference value at any of the three gas levels. To calculate the measurement error at each level, take the absolute value of the difference between the reference value and mean CEM response, divide the result by the reference value, and then multiply by 100. Alternatively, the results at any gas level are acceptable if the absolute value of the difference between the average monitor response and the average reference value, *i.e.*, $|R - A|$ in Equation A–4 of this appendix, does not exceed 0.8 $\mu g/m^3$. The principal and alternative performance specifications in this section also apply to the single-level system integrity check described in section 2.6 of appendix B to this part.

* * * * *

5.1 *Reference Gases*

* * * * *

5.1.4 EPA Protocol Gases

(a) An EPA Protocol Gas is a calibration gas mixture prepared and analyzed according to Section 2 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121 or such revised procedure as approved by the Administrator (EPA Traceability Protocol).

(b) An EPA Protocol Gas must have a specialty gas producer-certified uncertainty (95-percent confidence interval) that must not be greater than 2.0 percent of the certified concentration (tag value) of the gas mixture. The uncertainty must be calculated using the statistical procedures (or equivalent statistical techniques) that are listed in Section 2.1.8 of the EPA Traceability Protocol.

(c) On and after January 1, 2009, a specialty gas producer advertising calibration gas certification with the EPA Traceability Protocol or distributing calibration gases as ''EPA Protocol Gas'' must participate in the EPA Protocol Gas Verification Program (PGVP) described in Section 2.1.10 of the EPA Traceability Protocol or it cannot use ''EPA'' in any form of advertising for these products, unless approved by the Administrator. A specialty gas producer not participating in the PGVP may not certify a calibration gas as an EPA Protocol Gas, unless approved by the Administrator.

(d) A copy of EPA–600/R–97/121 is available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA, 703–605–6585 or *http://www.ntis.gov,* and from *http://www.epa.gov/ttn/emc/news.html* or *http://www.epa.gov/appcdwww/tsb/index.html.*

* * * * *

5.1.9 Mercury Standards

For 7-day calibration error tests of Hg concentration monitors and for daily calibration error tests of Hg monitors, either NIST-traceable elemental Hg standards (as defined in § 72.2 of this chapter) or a NIST-traceable source of oxidized Hg (as defined in § 72.2 of this chapter) may be used. For linearity checks, NIST-traceable elemental Hg standards shall be used. For 3-level and single-point system integrity checks under § 75.20(c)(1)(vi), sections 6.2(g) and 6.3.1 of this appendix, and sections 2.1.1, 2.2.1 and 2.6 of appendix B to this part, a NIST-traceable source of oxidized Hg shall be used.

Alternatively, other NIST-traceable standards may be used for the required checks, subject to the approval of the Administrator. Notwithstanding these requirements, Hg calibration standards that are not NIST-traceable may be used for the tests described in this section until December 31, 2009. However, on and after January 1, 2010, only NIST-traceable calibration standards shall be used for these tests.

* * * * *

6.1 *General Requirements*

* * * * *

6.1.2 *Requirements for Air Emission Testing Bodies*

(a) On and after January 1, 2009, any Air Emission Testing Body (AETB) conducting relative accuracy test audits of CEMS and sorbent trap monitoring systems under this part must conform to the requirements of ASTM D7036–04 (incorporated by reference under § 75.6 of this part). This section is not applicable to daily operation, daily calibration error checks, daily flow interference checks, quarterly linearity checks or routine maintenance of CEMS.

(b) The AETB shall provide to the affected source(s) certification that the AETB operates in conformance with, and that data submitted to the Agency has been collected in accordance with, the requirements of ASTM D7036–04 (incorporated by reference under § 75.6 of this part). This certification may be provided in the form of:

(1) A certificate of accreditation of relevant scope issued by a recognized, national accreditation body; or

(2) A letter of certification signed by a member of the senior management staff of the AETB.

(c) The AETB shall either provide a Qualified Individual on-site to conduct or shall oversee all relative accuracy testing carried out by the AETB as required in ASTM D7036–04 (incorporated by reference under § 75.6 of this part). The Qualified Individual shall provide the affected source(s) with copies of the qualification credentials relevant to the scope of the testing conducted.

* * * * *

6.2 *Linearity Check (General Procedures)*

* * * Notwithstanding these requirements, if the SO_2 or NO_X span value for a particular monitor range is ≤ 30 ppm, that range is exempted from the linearity check requirements of this part, for initial certification, recertification, and for on-going quality-assurance. For units with two measurement ranges (high and low) for a particular parameter, perform a linearity check on both the low scale (except for SO_2 or NO_X span values ≤ 30 ppm) and the high scale. Note that for a NO_X-diluent monitoring system with two NO_X measurement ranges, if the low NO_X scale has a span value ≤ 30 ppm and is exempt from linearity checks, this does not exempt either the diluent monitor or the high NO_X scale (if the span is > 30 ppm) from linearity check requirements.

* * * * *

(g) For Hg monitors, follow the guidelines in section 2.2.3 of this appendix in addition to the applicable procedures in section 6.2 when performing the system integrity checks described in § 75.20(c)(1)(vi) and in sections 2.1.1, 2.2.1 and 2.6 of appendix B to this part.

(h) For Hg concentration monitors, if moisture is added to the calibration gas during the required linearity checks or system integrity checks, the moisture content of the calibration gas must be accounted for. Under these circumstances, the dry basis concentration of the calibration gas shall be used to calculate the linearity error or measurement error (as applicable).

* * * * *

6.3.1 *Gas Monitor 7-day Calibration Error Test*

* * * Also for Hg monitors, if moisture is added to the calibration gas, the added moisture must be accounted for and the dry-basis concentration of the calibration gas shall be used to calculate the calibration error.

* * * * *

6.4. *Cycle Time Test*

Perform cycle time tests for each pollutant concentration monitor and continuous emission monitoring system while the unit is operating, according to the following procedures. Use a zero-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. For Hg monitors, the calibration gas used for this test may either be the elemental or oxidized form of Hg. To determine the downscale cycle time, measure the concentration of the flue gas emissions until the response stabilizes. Record the stable emissions value. Inject a zero-level concentration calibration gas into the probe tip (or injection port leading to the calibration cell, for in situ systems with no probe). Record the time of the zero gas injection, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of the zero gas until the response stabilizes. Record the stable ending calibration gas reading. Determine the downscale cycle time as the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending zero gas reading. Then repeat the procedure, starting with stable stack emissions and injecting the high-level gas, to determine the upscale cycle time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable stack emissions value and the stable ending high-level gas reading. Use the following criteria to assess when a stable reading of stack emissions or calibration gas concentration has been attained. A stable value is equivalent to a reading with a change of less than 2.0 percent of the span value for 2 minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. Alternatively, the reading is considered stable if it changes by no more than 0.5 ppm, 0.5 $\mu g/m^3$ (for Hg), or 0.2% CO_2 or O_2 (as applicable) for two minutes. (Owners or operators of systems which do not record data in 1-minute or 3-minute intervals may petition the Administrator under § 75.66 for alternative stabilization criteria). For monitors or monitoring systems that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible cycle time. Refer to Figures 6a and 6b in this appendix for example calculations of upscale and downscale cycle times. Report the slower of the two cycle times (upscale or downscale) as the cycle time for the analyzer. Prior to January 1, 2009 for the NO_X-diluent continuous emission monitoring system test, either record and report the longer cycle time of the two component analyzers as the system cycle time or record the cycle time for each component analyzer separately (as applicable). On and after January 1, 2009, record the cycle time for each component analyzer separately. For time-shared systems, perform the cycle time tests at each probe locations that will be polled within the same 15-minute period during monitoring system operations. To determine the cycle time for time-shared systems, at each monitoring location, report the sum of the cycle time observed at that monitoring location plus the sum of the time required for all purge cycles (as determined by the continuous emission monitoring system manufacturer) at each of the probe locations of the time-shared systems. For monitors with dual ranges, report the test results for each range separately. Cycle time test results are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of the cycle times exceed 15 minutes. The status of emissions data from a monitor prior to and during a cycle time test period shall be determined as follows:

* * * * *

6.5 * * *

(e) Complete each single-load relative accuracy test audit within a period of 168 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter). Notwithstanding this requirement, up to 336 consecutive unit or stack operating hours may be taken to complete the RATA of a Hg monitoring system, when ASTM 6784–02 (incorporated by reference under § 75.6 of this part) or Method 29 in appendix A–8 to part 60 of this chapter is used as the reference method. For 2-level and 3-level flow monitor RATAs, complete all of the RATAs at all levels, to the extent practicable, within a period of 168 consecutive unit (or stack) operating hours; however, if this is not possible, up to 720 consecutive unit (or stack) operating hours may be taken to complete a multiple-load flow RATA.

* * * * *

6.5.2.1 * * *

(e) The owner or operator shall report the upper and lower boundaries of the range of operation for each unit (or combination of units, for common stacks), in units of megawatts or thousands of lb/hr or mmBtu/hr of steam production or ft/sec (as applicable), in the electronic monitoring plan required under § 75.53. Except for peaking units and LME units, the owner or operator shall indicate, in the electronic monitoring plan, the load level (or levels) designated as normal under this section and shall also indicate the two most frequently used load levels.

* * * * *

6.5.6 * * *

(c) For Hg monitoring systems, use the same basic approach for traverse point selection that is used for the other gas monitoring system RATAs, except that the stratification test provisions in sections 8.1.3 through 8.1.3.5 of Method 30A shall apply, rather than the provisions of sections 6.5.6.1 through 6.5.6.3 of this appendix.

6.5.10 *Reference Methods*

The following methods are from appendix A to part 60 of this chapter or have been published by ASTM, and are the reference methods for performing relative accuracy test audits under this part: Method 1 or 1A in appendix A–1 to part 60 of this chapter for siting; Method 2 in appendices A–1 and A–2 to part 60 of this chapter or its allowable alternatives in appendix A to part 60 of this chapter (except for Methods 2B and 2E in appendix A–1 to part 60 of this chapter) for stack gas velocity and volumetric flow rate; Methods 3, 3A or 3B in appendix A–2 to part 60 of this chapter for O_2 and CO_2; Method 4 in appendix A–3 to part 60 of this chapter for moisture; Methods 6, 6A or 6C in appendix A–4 to part 60 of this chapter for SO_2; Methods 7, 7A, 7C, 7D or 7E in appendix A–4 to part 60 of this chapter for NO_X, excluding the exceptions of Method 7E in appendix A–4 to part 60 of this chapter identified in § 75.22(a)(5); and for Hg, either ASTM D6784–02 (the Ontario Hydro Method) (incorporated by reference under § 75.6 of this part), Method 29 in appendix A–8 to part 60 of this chapter, Method 30A, or Method 30B When using Method 7E in appendix A–4 to part 60 of this chapter for measuring NO_X concentration, total NO_X, both NO and NO_2, must be measured.

* * * * *

7.6 *Bias Test and Adjustment Factor*

* * * * *

7.6.1 * * * To calculate bias for a Hg monitoring system when using the Ontario Hydro Method or Method 29 in appendix A–8 to part 60 of this chapter, ''d'' is, for each data point, the difference between the average Hg concentration value (in $\mu g/m^3$) from the paired Ontario Hydro or Method 29 in appendix A–8 to part 60 of this chapter sampling trains and the concentration measured by the monitoring system. For sorbent trap monitoring systems, use the average Hg concentration measured by the paired traps in the calculation of ''d''.

* * * * *

7.7 * * *

(a) * * *

R_{ref} = Reference value of the flow-to-load ratio, from the most recent normal-load flow RATA, scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr of steam output).

* * * * *

L_{avg} = Average unit load during the normal-load flow RATA, megawatts, 1000 lb/hr of steam, or mmBtu/hr of thermal output.

* * * * *

(c) * * *

$(GHR)_{ref}$ = Reference value of the gross heat rate at the time of the most recent normal-load flow RATA, Btu/kwh, Btu/lb steam load, or Btu heat input/mmBtu steam output.

* * * * *

L_{avg} = Average unit load during the normal-load flow RATA, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

Figure 6a. Upscale Cycle Time Test

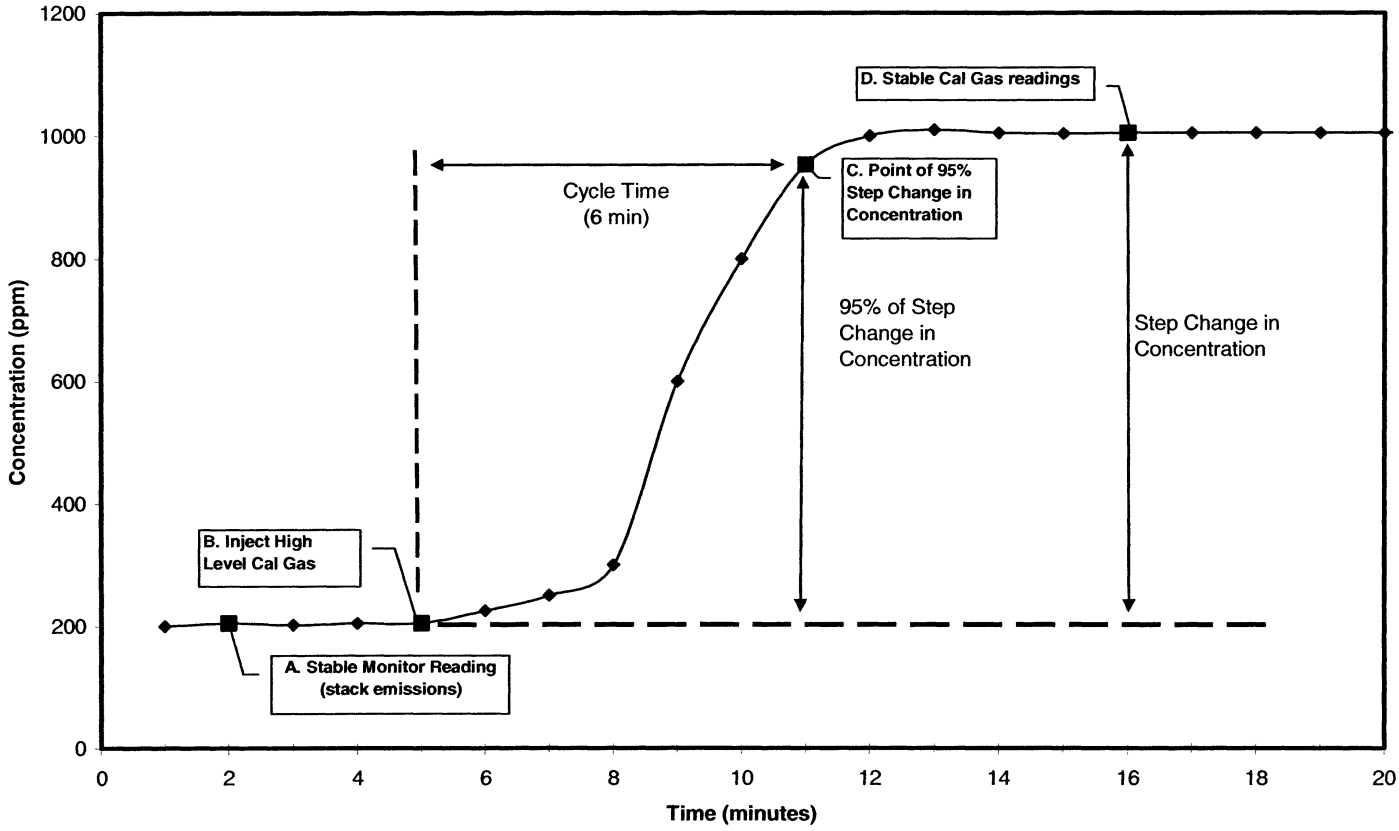
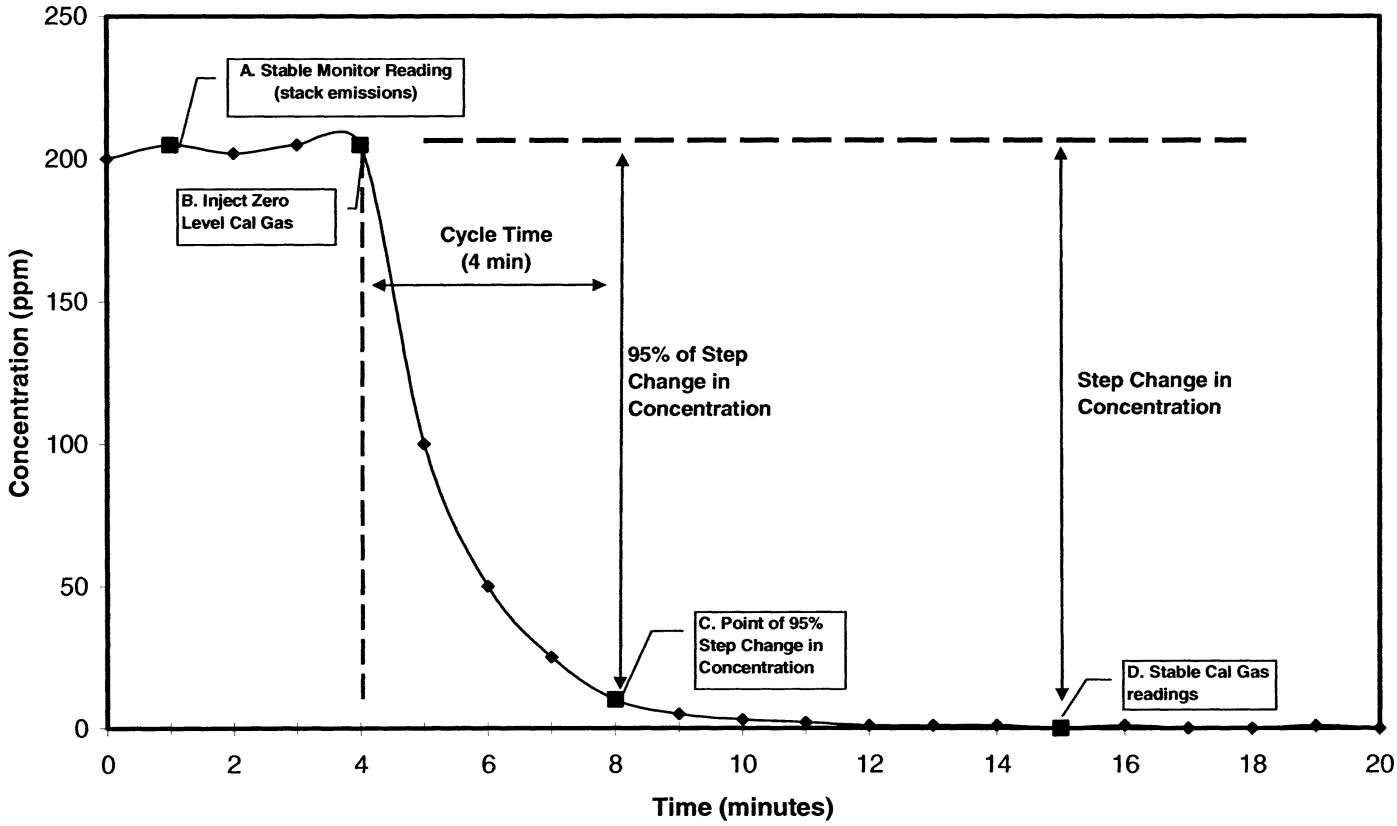


Figure 6b. Downscale Cycle Time Test



A. To determine the upscale cycle time (Figure 6a), measure the flue gas emissions until the response stabilizes. Record the stabilized value (see section 6.4 of this appendix for the stability criteria).

B. Inject a high-level calibration gas into the port leading to the calibration cell or thimble (Point B). Allow the analyzer to stabilize. Record the stabilized value.

C. Determine the step change. The step change is equal to the difference between the final stable calibration gas value (Point D) and the stabilized stack emissions value (Point A).

D. Take 95% of the step change value and add the result to the stabilized stack emissions value (Point A). Determine the time at which 95% of the step change occurred (Point C).

E. Calculate the upscale cycle time by subtracting the time at which the calibration gas was injected (Point B) from the time at which 95% of the step change occurred (Point C). In this example, upscale cycle time = (11 − 5) = 6 minutes.

F. To determine the downscale cycle time (Figure 6b) repeat the procedures above, except that a zero gas is injected when the flue gas emissions have stabilized, and 95% of the step change in concentration is subtracted from the stabilized stack emissions value.

G. Compare the upscale and downscale cycle time values. The longer of these two times is the cycle time for the analyzer.

■ 41. Appendix B to Part 75 is amended by:

■ a. Adding section 1.1.4;

■ b. Revising section 2.1.1;

■ c. Revising paragraph (2) of section 2.1.1.2;

■ d. Revising paragraph (2) of section 2.1.5.1;

■ e. Adding paragraph (3) to section 2.1.5.1;

■ f. Adding a new fourth sentence to paragraph (e) of section 2.2.3;

■ g. Revising the terms ''R_h'' and ''L_h'' in paragraph (a) of section 2.2.5;

■ h. Revising the terms ''$(GHR)_h$'' and ''L_h'' in paragraph (a)(2) of section 2.2.5;

■ i. Removing the word ''five'' and adding in its place the word ''twenty'', and by removing the word ''years'' and adding in its place the word ''quarters'', in paragraph (c)(4) of section 2.3.1.3;

■ j. Revising paragraphs (d) and (g) of section 2.3.2;

■ k. Revising paragraphs (a)(2) and (c) of section 2.3.3;

■ l. Adding paragraph (d) to section 2.3.3;

■ m. Revising section 2.6;

■ n. Revising Figure 1; and

■ o. Revising Figure 2.

The revisions and additions read as follows:

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Assurance/Quality Control Program

* * * * *

1.1.4 The requirements in section 6.1.2 of appendix A to this part shall be met by any Air Emissions Testing Body (AETB) performing the semiannual/annual RATAs described in section 2.3 of this appendix and the Hg emission tests described in §§ 75.81(c) and 75.81(d)(4).

* * * * *

2. Frequency of Testing

* * * * *

2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-basis O_2 analyzers) according to the procedures in section 6.3.1 of appendix A to this part, and perform the daily calibration error test of each flow monitoring system according to the procedure in section 6.3.2 of appendix A to this part. When two measurement ranges (low and high) are required for a particular parameter, perform sufficient calibration error tests on each range to validate the data recorded on that range, according to the criteria in section 2.1.5 of this appendix.

* * * * *

2.1.1.2 * * *

(2) For each monitoring system that has passed the off-line calibration demonstration, off-line calibration error tests may be used on a limited basis to validate data, in accordance with paragraph (2) in section 2.1.5.1 of this appendix.

* * * * *

2.1.5.1 * * *

(2) For a monitor that has passed the off-line calibration demonstration, a combination of on-line and off-line calibration error tests may be used to validate data from the monitor, as follows. For a particular unit (or stack) operating hour, data from a monitor may be validated using a successful off-line calibration error test if: (a) An on-line calibration error test has been passed within the previous 26 unit (or stack) operating hours; and (b) the 26 clock hour data validation window for the off-line calibration error test has not expired. If either of these conditions is not met, then the data from the monitor are invalid with respect to the daily calibration error test requirement. Data from the monitor shall remain invalid until the appropriate on-line or off-line calibration error test is successfully completed so that both conditions (a) and (b) are met.

(3) For units with two measurement ranges (low and high) for a particular parameter, when separate analyzers are used for the low and high ranges, a failed or expired calibration on one of the ranges does not affect the quality-assured data status on the other range. For a dual-range analyzer (i.e., a single analyzer with two measurement scales), a failed calibration error test on either the low or high scale results in an out-of-control period for the monitor. Data from the monitor remain invalid until corrective actions are taken and ''hands-off'' calibration error tests have been passed on both ranges. However, if the most recent calibration error test on the high scale was passed but has expired, while the low scale is up-to-date on its calibration error test requirements (or vice-versa), the expired calibration error test does not affect the quality-assured status of the data recorded on the other scale.

* * * * *

2.2.3 * * *

(e) * * * For a dual-range analyzer, ''hands-off'' linearity checks must be passed on both measurement scales to end the out-of-control period. * * *

* * * * *

2.2.5 * * *

(a) * * *

R_h = Hourly value of the flow-to-load ratio, scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr thermal output).

* * * * *

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

* * * * *

(2) * * *

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam load, or 1000 mmBtu heat input/mmBtu thermal output.

* * * * *

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output; must be within + 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

* * * * *

2.3.2 * * *

(d) For single-load (or single-level) RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The subsequent RATA shall not be commenced until the monitor has successfully passed a calibration error test in accordance with section 2.1.3 of this appendix. Notwithstanding these requirements, when ASTM D6784–02 (incorporated by reference under § 75.6 of this part) or Method 29 in appendix A–8 to part 60 of this chapter is used as the reference method for the RATA of a Hg CEMS, if a calibration error test of the CEMS is failed during a RATA test period, any test run(s) completed prior to the failed calibration error test need not be repeated; however, the RATA may not continue until a subsequent calibration error test of the Hg CEMS has been passed. For multiple-load (or multiple-level) flow RATAs, each load level (or operating level) is treated as a separate RATA (*i.e.,* when a calibration error test is failed prior to completing the RATA at a particular load level (or operating level), only the RATA at that load level (or operating level) must be repeated; the results of any previously-passed RATA(s) at the other load level(s) (or operating level(s)) are unaffected, unless re-linearization of the monitor is required to correct the problem that caused the calibration failure, in which case a subsequent 3-load (or 3-level) RATA is required), except as otherwise provided in section 2.3.1.3(c)(5) of this appendix.

* * * * *

(g) Data validation for failed RATAs for a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions), a NO_X pollutant concentration monitor, and a NO_X-diluent monitoring system shall be done according to paragraphs (g)(1) and (g)(2) of this section:

(1) For a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) which also serves as the diluent component in a NO_X-diluent monitoring system, if the CO_2 (or O_2) RATA is failed, then both the CO_2 (or O_2) monitor and the associated NO_X-diluent system are considered out-of-control, beginning with the hour of completion of the failed CO_2 (or O_2) monitor RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B).

(2) This paragraph (g)(2) applies only to a NO_X pollutant concentration monitor that serves both as the NO_X component of a NO_X concentration monitoring system (to measure NO_X mass emissions) and as the NO_X component in a NO_X-diluent monitoring system (to measure NO_X emission rate in lb/mmBtu). If the RATA of the NO_X concentration monitoring system is failed, then both the NO_X concentration monitoring system and the associated NO_X-diluent monitoring system are considered out-of-control, beginning with the hour of completion of the failed NO_X concentration RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.7 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B).

* * * * *

2.3.3 RATA Grace Period

(a) * * *

(2) A required 3-load flow RATA has not been performed by the end of the calendar quarter in which it is due; or

* * * * *

(c) If, at the end of the 720 unit (or stack) operating hour grace period, the RATA has not been completed, data from the monitoring system shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the CEMS remain invalid until the hour of completion of a subsequent hands-off RATA. The deadline for the next test shall be either two QA operating quarters (if a semiannual RATA frequency is obtained) or four QA operating quarters (if an annual RATA frequency is obtained) after the quarter in which the RATA is completed, not to exceed eight calendar quarters.

* * * * *

(d) When a RATA is done during a grace period in order to satisfy a RATA requirement from a previous quarter, the deadline for the next RATA shall determined as follows:

(1) If the grace period RATA qualifies for a reduced, (i.e., annual), RATA frequency the deadline for the next RATA shall be set at three QA operating quarters after the quarter in which the grace period test is completed.

(2) If the grace period RATA qualifies for the standard, (i.e., semiannual), RATA frequency the deadline for the next RATA shall be set at two QA operating quarters after the quarter in which the grace period test is completed.

(3) Notwithstanding these requirements, no more than eight successive calendar quarters shall elapse after the quarter in which the grace period test is completed, without a subsequent RATA having been conducted.

* * * * *

2.6 *System Integrity Checks for Hg Monitors*

For each Hg concentration monitoring system (except for a Hg monitor that does not have a converter), perform a single-point system integrity check weekly, i.e., at least once every 168 unit or stack operating hours, using a NIST-traceable source of oxidized Hg. Perform this check using a mid- or high-level gas concentration, as defined in section 5.2 of appendix A to this part. The performance specifications in paragraph (3) of section 3.2 of appendix A to this part must be met, otherwise the monitoring system is considered out-of-control, from the hour of the failed check until a subsequent system integrity check is passed. If a required system integrity check is not performed and passed within 168 unit or stack operating hours of last successful check, the monitoring system shall also be considered out of control, beginning with the 169th unit or stack operating hour after the last successful check, and continuing until a subsequent system integrity check is passed. This weekly check is not required if the daily calibration assessments in section 2.1.1 of this appendix are performed using a NIST-traceable source of oxidized Hg.

* * * * *

FIGURE 1 TO APPENDIX B OF PART 75.—QUALITY ASSURANCE TEST REQUIREMENTS

Test	Basic QA test frequency requirements *				
	Daily *	Weekly	Quarterly *	Semi-annual *	Annual
Calibration Error Test (2 pt.)	✔				
Interference Check (flow)	✔				
Flow-to-Load Ratio			✔		
Leak Check (DP flow monitors)			✔		
Linearity Check or System Integrity Check ** (3 pt.)			✔		
Single-point System Integrity Check **		✔			
RATA (SO_2, NO_X, CO_2, O_2, H_2O) [1]				✔	
RATA (All Hg monitoring systems)					✔
RATA (flow) [1 2]				✔	

* "Daily" means operating days, only. "Weekly" means once every 168 unit or stack operating hours. "Quarterly" means once every QA operating quarter. "Semiannual" means once every two QA operating quarters. "Annual" means once every four QA operating quarters.

** The system integrity check applies only to Hg monitors with converters. The single-point weekly system integrity check is not required if daily calibrations are performed using a NIST-traceable source of oxidized Hg. The 3-point quarterly system integrity check is not required if a linearity check is performed.

[1] Conduct RATA annually (i.e., once every four QA operating quarters), if monitor meets accuracy requirements to qualify for less frequent testing.

[2] For flow monitors installed on peaking units, bypass stacks, or units that qualify for single-level RATA testing under section 6.5.2(e) of this part, conduct all RATAs at a single, normal load (or operating level). For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-load and 2-load (or single-level and 2-level) RATAs may be done if a monitor is on a semiannual frequency. A single-load (or single-level) RATA may be done in lieu of a 2-load (or 2-level) RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥85.0 percent of the time. A 3-level RATA is required at least once every five calendar years and whenever a flow monitor is re-linearized, except for flow monitors exempted from 3-level RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.

FIGURE 2 TO APPENDIX B OF PART 75.—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM

RATA	Semiannual [W] (percent)	Annual [W]
SO_2 or NO_X [Y]	7.5% <RA ≤10.0% or ±15.0 ppm [X]	RA ≤ 7.5% or ±12.0 ppm [X].
SO_2-diluent	7.5% <RA ≤10.0% or ±0.030 lb/mmBtu [X]	RA ≤7.5% or ±0.025 lb/mmBtu =G5X.
NO_X-diluent	7.5% <RA ≤10.0% or ±0.020 lb/mmBtu [X]	RA ≤ 7.5% or ±0. 015 lb/mmBtu [X].
Flow	7.5% < RA ≤ 10.0% or ±2.0 fps [X]	RA ≤ 7.5% or ±1.5 fps [X].
CO_2 or O_2	7.5% < RA ≤ 10.0% or ±1.0% CO_2/O_2 [X]	RA ≤ 7.5% or ±0.7% CO_2/O_2 [X].
Hg [X]	N/A	RA < 20.0% or ± 1.0 μg/scm [X].
Moisture	7.5% <RA ≤10.0% or ±1.5% H_2O [X]	RA ≤7.5% or ±1.0% H_2O [X].

[W] The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.

[X] The difference between monitor and reference method mean values applies to moisture monitors, CO_2, and O_2 monitors, low emitters of SO_2, NO_X, or Hg, or and low flow, only. The specifications for Hg monitors also apply to sorbent trap monitoring systems.

[Y] A NO_X concentration monitoring system used to determine NO_X mass emissions under § 75.71.

■ 42. Appendix D to Part 75 is amended by:

■ a. Revising section 2.1.5.1;

■ b. Removing all "±" symbols from paragraph (c) of section 2.1.6.1;

■ c. Revising the R_{base} and L_{avg} variable definitions in paragraph (a) of section 2.1.7.1;

■ d. Revising the terms "$(GHR)_{base}$" and "L_{avg}" in paragraph (c) of section 2.1.7.1;

■ e. Revising the terms "R_h" and "L_h" in paragraph (a) of section 2.1.7.2;

■ f. Revising the terms "$(GHR)_h$" and "L_h" in paragraph (c) of section 2.1.7.2;

■ g. Removing "D4177–82 (Reapproved 1990)" and adding in its place "D4177–95 (Reapproved 2000)", in the first sentence of section 2.2.3;

■ h. Removing "D4057–88 'Standard Practice for Manual Sampling of Petroleum and Petroleum Products' (incorporated by reference under § 75.6)" and adding in its place, "ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products

(incorporated by reference under § 75.6 of this part)'', in sections 2.2.4.1 and 2.2.4.2, and in paragraph (c) of section 2.2.4.3;

■ i. Revising sections 2.2.5, 2.2.6, and 2.2.7;

■ j. Revising paragraphs (a)(2) and (e) of section 2.3.1.4;

■ k. Revising section 2.3.3.1.2;

■ l. Revising section 2.3.4;

■ m. Adding two sentences at the end of section 2.3.4.1;

■ n. Revising paragraphs (b)(2) and (c) of section 2.3.7;

■ o. Revising section 3.2.2; and

■ p. Revising section 3.5.1.

The revisions and additions read as follows:

Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units.

* * * * *

2. Procedure

* * * * *

2.1.5.1 Use the procedures in the following standards to verify flowmeter accuracy or design, as appropriate to the type of flowmeter: ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi; ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters; American Gas Association Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition), and Part 3: Natural Gas Applications (August 1992 edition) (excluding the modified flow-calculation method in part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April 1996); ASME–MFC–5M–1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters; ASME MFC–6M–1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters; ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles; ISO 8316: 1987(E) Measurement of Liquid Flow in Closed Conduits-Method by Collection of the Liquid in a Volumetric Tank; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4—Proving Systems, Section 2—Pipe Provers (Provers Accumulating at Least 10,000 Pulses), Second Edition, March 2001, and Section 5—Master-Meter Provers, Second Edition, May 2000; American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005; or ASME MFC–9M–1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method, for all other flowmeter types (all incorporated by reference under § 75.6 of this part). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document such procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit, and submit a petition signed by the designated representative under § 75.66(c). If the flowmeter accuracy exceeds 2.0 percent of the upper range value, the flowmeter does not qualify for use under this part.

* * * * *

2.1.7.1

(a) * * *

Where:

R_{base} = Value of the fuel flow rate-to-load ratio during the baseline period; 100 scfh/MWe, 100 scfh/klb per hour steam load, or 100 scfh/mmBtu per hour thermal output for gas-firing; (lb/hr)/MWe, (lb/hr)/klb per hour steam load, or (lb/hr)/mmBtu per hour thermal output for oil-firing.

* * * * *

L_{avg} = Arithmetic average unit load during the baseline period, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

* * * * *

(c) * * *

Where:

$(GHR)_{base}$ = Baseline value of the gross heat rate during the baseline period, Btu/kwh, Btu/lb steam load, or 1000mmBtu heat input/mmBtu thermal output.

* * * * *

L_{avg} = Average (mean) unit load during the baseline period, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

* * * * *

2.1.7.2

(a) * * *

Where:

R_h = Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, (lb/hr)/1000 lb/hr of steam load, 100 scfh/(mmBtu/hr of steam load), or (lb/hr)/(mmBtu/hr thermal output).

* * * * *

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

* * * * *

(c) * * *

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh, Btu/lb steam load, or mmBtu heat input/mmBtu thermal output.

* * * * *

L_h = Hourly unit load, megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output.

* * * * *

2.2.5 For each oil sample that is taken on-site at the affected facility, split and label the sample and maintain a portion (at least 200 cc) of it throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. This requirement does not apply to oil samples taken from the fuel supplier's storage container, as described in section 2.2.4.3 of this appendix. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129–00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), ASTM D1552–01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), ASTM D2622–98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, ASTM D4294–98, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry, or ASTM D5453–06, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence (all incorporated by reference under § 75.6 of this part). Alternatively, the oil samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.6 Where the flowmeter records volumetric flow rate rather than mass flow rate, analyze oil samples to determine the density or specific gravity of the oil. Determine the density or specific gravity of the oil sample in accordance with ASTM D287–92 (Reapproved 2000), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), ASTM D1217–93 (Reapproved 1998), Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, ASTM D1481–93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, ASTM D1480–93 (Reapproved 1997), Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, ASTM D1298–99, Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, or ASTM D4052–96 (Reapproved 2002), Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter (all incorporated by reference under § 75.6 of this part). Alternatively, the oil samples may be analyzed for density or specific gravity by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, ASTM D4809–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), or ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke (all incorporated by reference under § 75.6 of this part) or any other procedures listed in section 5.5 of appendix F of this part. Alternatively,

the oil samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

* * * * *

2.3.1.4 * * *

(a) * * *

(2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of pipeline natural gas in § 72.2 of this chapter, except where the results of at least 100 daily (or more frequent) total sulfur samples are provided by the fuel supplier. In that case you may opt to convert these data to monthly averages and then if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if ≥ 98 percent of the 100 (or more) samples have a total sulfur content of 0.5 grains/100 scf or less and if the GCV or percent methane requirement is also met; or

* * * * *

(e) If a fuel qualifies as pipeline natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as pipeline natural gas based on fuel sampling and analysis, on-going sampling of the fuel's sulfur content is required annually and whenever the fuel supply source changes. For the purposes of this paragraph (e), sampling ''annually'' means that at least one sample is taken in each calendar year. If the results of at least 100 daily (or more frequent) total sulfur samples have been provided by the fuel supplier since the last annual assessment of the fuel's sulfur content, the data may be used as follows to satisfy the annual sampling requirement for the current year. If this option is chosen, all of the data provided by the fuel supplier shall be used. First, convert the data to monthly averages. Then, if, for each month, the average total sulfur content is 0.5 grains/100 scf or less, and if the GCV or percent methane requirement is also met, the fuel qualifies as pipeline natural gas. Alternatively, the fuel qualifies as pipeline natural gas if the analysis of the 100 (or more) total sulfur samples since the last annual assessment shows that ≥ 98 percent of the samples have a total sulfur content of 0.5 grains/100 scf or less and if the GCV or percent methane requirement is also met. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

* * * * *

2.3.3.1.2 Use one of the following methods when using manual sampling (as applicable to the type of gas combusted) to determine the sulfur content of the fuel: ASTM D1072–06, Standard Test Method for Total Sulfur in Fuel Gases by Combustion and Barium Chloride Titration, ASTM D4468–85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, or ASTM D3246–96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, (all incorporated by reference under § 75.6 of this part). Alternatively, the gas samples may be analyzed for percent sulfur by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

* * * * *

2.3.4 Gross Calorific Values for Gaseous Fuels

Determine the GCV of each gaseous fuel at the frequency specified in this section, using one of the following methods: ASTM D1826–94 (Reapproved 1998), ASTM D3588–98, ASTM D4891–89 (Reapproved 2006), GPA Standard 2172–96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (all incorporated by reference under § 75.6 of this part). Use the appropriate GCV value, as specified in section 2.3.4.1, 2.3.4.2, or 2.3.4.3 of this appendix, in the calculation of unit hourly heat input rates. Alternatively, the gas samples may be analyzed for heat content by any consensus standard method prescribed for the affected unit under part 60 of this chapter.

2.3.4.1 GCV of Pipeline Natural Gas

* * * If multiple GCV samples are taken and analyzed in a particular month, the GCV values from all samples shall be averaged arithmetically to obtain the monthly GCV. Then, apply the monthly average GCV value as described in paragraph (c) in section 2.3.7 of this appendix.

* * * * *

2.3.7 * * *

(b) * * *

(2) For natural gas, if only one sample is taken, apply the results beginning at the date on which the sample was taken. If multiple samples are taken and averaged, apply the results beginning at the date on which the last sample used in the annual assessment was taken;

* * * * *

(c) For monthly samples of the fuel GCV:

(1) If the actual monthly value is to be used in the calculations and only one sample is taken, apply the results starting from the date on which the sample was taken. If multiple samples are taken and averaged, apply the monthly average GCV value to the entire month; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value to all hours in each month of the quarter unless a higher value is obtained in a monthly GCV sample (or, if multiple samples are taken and averaged, if the monthly average exceeds the assumed value). In that case, if only one monthly sample is taken, use the sampled value, starting from the date on which the sample was taken. If multiple samples are taken and averaged, use the average value for the entire month in which the assumed value was exceeded. Consider the sample (or, if applicable, monthly average) results to be the new assumed value. Continue using the new assumed value unless and until one of the following occurs (as applicable to the reporting option selected): The assumed value is superseded by a higher value from a subsequent monthly sample (or by a higher monthly average); or the assumed value is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or both the calendar year in which the new sampled value (or monthly average) exceeded the assumed value and the subsequent calendar year have elapsed.

* * * * *

3.2.2 Convert density, specific gravity, or API gravity of the oil sample to density of the oil sample at the sampling location's temperature using ASTM D1250–07, Standard Guide for Use of the Petroleum Measurement Tables (incorporated by reference under (§ 75.6 of this part).

* * * * *

3.5.1 Hourly SO_2 Mass Emissions from the Combustion of all Fuels. Determine the total mass emissions for each hour from the combustion of all fuels using Equation D–12 (On and after January 1, 2009, determine the total mass emission rate (in lbs/hr) for each hour from the combustion of all fuels by dividing Equation D–12 by the actual unit operating time for the hour):

$$M_{So2-hr} = \sum_{all-fuels} SO2_{rate-1}\, t_i \qquad \text{(Eq. D-12)}$$

Where:

MSO_2-hr = Total mass of SO_2 emissions from all fuels combusted during the hour, lb.

SO_2 rate − I = SO_2 mass emission rate for each type of gas or oil fuel combusted during the hour, lb/hr.

ti = Time each gas or oil fuel was combusted for the hour (fuel usage time), fraction of an hour (in equal increments that can

range from one hundredth to one quarter of an hour, at the option of the owner or operator).

* * * * *

■ 43. Appendix E to part 75 is amended by:

■ a. Adding a new sentence to the end of section 2.1;

■ b. Revising the seventh sentence of section 2.1.2.1;

■ c. Revising sections 2.1.2.2 and 2.1.2.3;

■ d. Removing the phrase ''(MWge or steam load in 1000 lb/hr)'' and adding in its place the phrase ''(MWge or steam load in 1000 lb/hr, or mmBtu/hr thermal output)'', in section 2.4.1;

■ e. Revising section 2.5.2; and

■ f. Adding section 2.5.2.4.

The revisions and additions read as follows:

Appendix E to Part 75—Optional NO_X Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

* * * * *

2.1 *Initial Performance Testing*

* * * The requirements in section 6.1.2 of appendix A to this part shall be met by any Air Emissions Testing Body (AETB) performing O_2 and NO_X concentration measurements under this appendix, either for units using the excepted methodology in this appendix or for units using the low mass emissions excepted methodology in § 75.19.

* * * * *

2.1.2.1 * * * Use a minimum of 12 sample points, located according to Method 1 in appendix A–1 to part 60 of this chapter.

* * * * *

2.1.2.2 For stationary gas turbines, sample at a minimum of 12 points per run at each load level. Locate the sample points according to Method 1 in appendix A–1 to part 60 of this chapter. For each fuel or consistent combination of fuels (and, optionally, for each combination of fuels), measure the NO_X and O_2 concentrations at each sampling point using methods 7E and 3A in appendices A–4 and A–2 to part 60 of this chapter. For diesel or dual fuel reciprocating engines, select the sampling site to be as close as practicable to the exhaust of the engine.

2.1.2.3 Allow the unit to stabilize for a minimum of 15 minutes (or longer if needed for the NO_X and O_2 readings to stabilize) prior to commencing NO_X, O_2, and heat input measurements. Determine the measurement system response time according to sections 8.2.5 and 8.2.6 of method 7E in appendix A–4 to part 60 of this chapter. When inserting the probe into the flue gas for the first sampling point in each traverse, sample for at least one minute plus twice the measurement system response time (or longer, if necessary to obtain a stable reading). For all other sampling points in each traverse, sample for at least one minute plus the measurement system response time (or longer, if necessary to obtain a stable reading). Perform three test runs at each load condition and obtain an arithmetic average of the runs for each load condition. During each test run on a boiler, record the boiler excess oxygen level at 5 minute intervals.

* * * * *

2.5.2 Substitute missing NO_X emission rate data using the highest NO_X emission rate tabulated during the most recent set of baseline correlation tests for the same fuel or, if applicable, combination of fuels, except as provided in sections 2.5.2.1, 2.5.2.2, 2.5.2.3, and 2.5.2.4 of this appendix.

* * * * *

2.5.2.4 Whenever 20 full calendar quarters have elapsed following the quarter of the last baseline correlation test for a particular type of fuel (or fuel mixture), without a subsequent baseline correlation test being done for that type of fuel (or fuel mixture), substitute the fuel-specific NO_X MER (as defined in § 72.2 of this chapter) for each hour in which that fuel (or mixture) is combusted until a new baseline correlation test for that fuel (or mixture) has been successfully completed. For fuel mixtures, report the highest of the individual MER values for the components of the mixture.

* * * * *

■ 44. Appendix F to Part 75 is amended by:

■ a. Removing the second and third sentences from the introductory text of section 2;

■ b. Removing the phrase ''method 19 in appendix A of part 60 of this chapter'' and adding in its place the phrase ''Method 19 in appendix A–7 to part 60 of this chapter'', in the last sentence of section 3.1 and in the last sentence of section 3.2;

■ c. Adding the phrase '', or (if applicable) in the equations in Method 19 in appendix A–7 to part 60 of this chapter'' after the words ''of this appendix'', in section 3.3;

■ d. Removing the second and third sentences from section 3.3.4;

■ e. Adding sections 3.3.4.1 and 3.3.4.2;

■ f. Revising Table 1;

■ g. Revising the text preceding Equation F–7a, in section 3.3.6;

■ h. Revising section 3.3.6.1;

■ i. Revising section 3.3.6.2;

■ j. Revising sections 3.3.6.3 and 3.3.6.4;

■ k. Adding section 3.3.6.5;

■ l. Adding the words ''either measured directly with a CO_2 monitor or calculated from wet-basis O_2 data using Equation F–14b,'' after the words ''wet basis,'' in the first sentence of the C_h variable definition, and by removing the second and third sentences from the C_h variable definition, in section 4.1;

■ m. Revising section 4.4.1;

■ n. Removing the second and third sentences from the $\%CO_{2w}$ variable definition in 5.2.1;

■ o. Removing the second and third sentences from the $\%CO_{2d}$ variable definition in 5.2.2;

■ p. Removing the second and third sentences from the $\%O_{2w}$ variable definition, and by adding a new sentence at the end of the paragraph, in section 5.2.3;

■ q. Removing the second and third sentences from the $\%O_{2d}$ variable definition, in section 5.2.4;

■ r. Revising the definition of ''GCV_o'' in paragraph (a) of section 5.5.1;

■ s. Revising the definition of ''GCV_g'' in section 5.5.2;

■ t. Revising section 5.5.3.1;

■ u. Revising section 5.5.3.2;

■ v. Removing the phrase ''as measured by ASTM D3176–89, D1989–92, D3286–91a, or D2015–91, Btu/lb'' and adding in its place the phrase ''as measured by ASTM D3176–89 (Reapproved 2002), or ASTM D5865–01a, Btu/lb. (incorporated by reference under § 75.6 of this part).'' in the definition of the GCV_c variable in Equation F–21;

■ w. Removing the word ''lb/hr'' and adding in its place the phrase ''lb/hr, or mmBtu/hr'' in the definition of the SF variable in Equation F–21b;

■ x. Revising the heading and text of section 7;

■ y. Adding the words ''of this appendix'' after the words ''section 8.1, 8.2, or 8.3'' and after the words ''section 8.4'' in the introductory text for section 8;

■ z. Revising sections 8.1 and 8.1.1;

■ aa. Revising section 8.2;

■ bb. Adding sections 8.2.1 and 8.2.2;

■ cc. Revising section 8.3;

■ dd. Revising section 8.4; and

■ ee. Adding section 10.

The revisions and additions read as follows:

Appendix F to Part 75—Conversion Procedures.

* * * * *

3.3.4 * * *

3.3.4.1 For boilers, a minimum concentration of 5.0 percent CO_2 or a maximum concentration of 14.0 percent O_2 may be substituted for the measured diluent gas concentration value for any operating hour in which the hourly average CO_2 concentration is < 5.0 percent CO_2 or the hourly average O_2 concentration is > 14.0 percent O_2. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 or a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values for any operating hour in which the hourly average CO_2 concentration is < 1.0 percent CO_2 or the hourly average O_2 concentration is > 19.0 percent O_2.

3.3.4.2 If NO_X emission rate is calculated using either Equation 19–3 or 19–5 in Method 19 in appendix A–7 to part 60 of this chapter, a variant of the equation shall be used whenever the diluent cap is applied. The modified equations shall be designated as Equations 19–3D and 19–5D, respectively.

Equation 19–3D is structurally the same as Equation 19–3, except that the term ''$\%O_{2w}$'' in the denominator is replaced with the term ''$\%O_{2dc} \times [(100 - \% H_2O)/100]$'', where $\%O_{2dc}$ is the diluent cap value. The numerator of Equation 19–5D is the same as Equation 19–5; however, the denominator of Equation 19–5D is simply ''$20.9 - \%O_{2dc}$'', where $\%O_{2dc}$ is the diluent cap value.

* * * * *

TABLE 1.—F- AND F_c-FACTORS [1]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–99 [2]):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1] Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.
[2] Incorporated by reference under § 75.6 of this part.

* * * * *

3.3.6 Equations F–7a and F–7b may be used in lieu of the F or F_c factors specified in Section 3.3.5 of this appendix to calculate a site-specific dry-basis F factor (dscf/mmBtu) or a site-specific F_c factor (scf CO_2/mmBtu), on either a dry or wet basis. At a minimum, the site-specific F or F_c factor must be based on 9 samples of the fuel. Fuel samples taken during each run of a RATA are acceptable for this purpose. The site-specific F or F_c factor must be re-determined at least annually, and the value from the most recent determination must be used in the emission calculations. Alternatively, the previous F or F_c value may continue to be used if it is higher than the value obtained in the most recent determination. The owner or operator shall keep records of all site-specific F or F_c determinations, active for at least 3 years. (Calculate all F- and F_c factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury).

* * * * *

3.3.6.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke, (solid fuels), ASTM D5291–02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, (liquid fuels) or computed from results using ASTM D1945–96 (Reapproved 2001), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, or ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography, (gaseous fuels) as applicable. (All of these methods are incorporated by reference under § 75.6 of this part.)

3.3.6.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke, and ASTM D240–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, or ASTM D4809–00, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) for oil; and ASTM D3588–98, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, or ASTM D1826–94 (Reapproved 1998), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, for gaseous fuels, as applicable. (All of these methods are incorporated by reference under § 75.6 of this part).

3.3.6.3 For affected units that combust a combination of a fuel (or fuels) listed in Table 1 in section 3.3.5 of this appendix with any fuel(s) not listed in Table 1, the F or F_c value is subject to the Administrator's approval under § 75.66.

3.3.6.4 For affected units that combust combinations of fuels listed in Table 1 in section 3.3.5 of this appendix, prorate the F or F_c factors determined by section 3.3.5 or 3.3.6 of this appendix in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \qquad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where,

X_i = Fraction of total heat input derived from each type of fuel (*e.g.*, natural gas, bituminous coal, wood). Each X_i value shall be determined from the best available information on the quantity of fuel combusted and the GCV value, over a specified time period. The owner or operator shall explain the method used to calculate X_i in the hardcopy portion of the monitoring plan for the unit. The X_i values may be determined and updated either hourly, daily, weekly, or monthly. In all cases, the prorated F-factor used in the emission calculations shall be determined using the X_i values from the most recent update.

F_i or $(F_c)_i$ = Applicable F or Fc factor for each fuel type determined in accordance with Section 3.3.5 or 3.3.6 of this appendix.

n = Number of fuels being combusted in combination.

3.3.6.5 As an alternative to prorating the F or Fc factor as described in section 3.3.6.4 of this appendix, a ''worst-case'' F or F_c factor may be reported for any unit operating hour.

The worst-case F or F_c factor shall be the highest F or F_c value for any of the fuels combusted in the unit.

* * * * *

4. Procedure for CO_2 Mass Emissions

* * * * *

4.4.1 If the owner or operator elects to use data from an O_2 monitor to calculate CO_2 concentration, the appropriate F and F_C factors from section 3.3.5 of this appendix shall be used in one of the following equations (as applicable) to determine hourly average CO_2 concentration of flue gases (in percent by volume) from the measured hourly average O_2 concentration:

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9} \qquad \text{(Eq. F-14a)}$$

Where:

CO_{2d} = Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.

F, F_C = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

O_{2d} = Hourly average O_2 concentration during unit operation, percent by volume, dry basis.

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \%H_2O}{100} \right) - O_{2w} \right] \qquad \text{(Eq. F-14b)}$$

Where:

CO_{2w} = Hourly average CO_2 concentration during unit operation, percent by volume, wet basis.

O_{2w} = Hourly average O_2 concentration during unit operation, percent by volume, wet basis.

F, F_c = F-factor or carbon-based FC-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

$\%H_2O$ = Moisture content of gas in the stack, percent.

For any hour where Equation F–14a or F–14b results in a negative hourly average CO_2 value, 0.0% CO_{2w} shall be recorded as the average CO_2 value for that hour.

* * * * *

5. Procedures for Heat Input

* * * * *

5.2.3 * * * For any operating hour where Equation F–17 results in an hourly heat input rate that is ≤ 0.0 mmBtu/hr, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

* * * * *

5.5.1 (a) * * *

GCV_o = Gross calorific value of oil, as measured by ASTM D240–00, ASTM D5865–01a, or ASTM D4809–00 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (all incorporated by reference under (§ 75.6 of this part).

* * * * *

5.5.2 * * *

GCV_g = Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826–94 (Reapproved 1998), ASTM D3588–98, ASTM D4891–89 (Reapproved 2006), GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Btu/100 scf (all incorporated by reference under § 75.6 of this part).

* * * * *

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in appendix A to part 60 of this chapter and use ASTM D2234–00, Standard Practice for Collection of a Gross Sample of Coal, (incorporated by reference under § 75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling. (When performing coal sampling solely for the purposes of the missing data procedures in § 75.36, use of ASTM D2234–00 is optional, and coal samples may be taken weekly.)

5.5.3.2 All ASTM methods are incorporated by reference under § 75.6 of this part. Use ASTM D2013–01, Standard Practice for Preparing Coal Samples for Analysis, for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke. On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods under §§ 75.23 and 75.66.

* * * * *

7. Procedures for SO_2 Mass Emissions, Using Default SO_2 Emission Rates and Heat Input Measured by CEMS

The owner or operator shall use Equation F–23 to calculate hourly SO_2 mass emissions in accordance with § 75.11(e)(1) during the combustion of gaseous fuel, for a unit that uses a flow monitor and a diluent gas monitor to measure heat input, and that qualifies to use a default SO_2 emission rate under section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. Equation F–23 may also be applied to the combustion of solid or liquid fuel that meets the definition of very low sulfur fuel in § 72.2 of this chapter, combinations of such fuels, or mixtures of such fuels with gaseous fuel, if the owner or operator has received approval from the Administrator under § 75.66 to use a site-specific default SO_2 emission rate for the fuel or mixture of fuels.

$$E_h = (ER)(HI) \qquad \text{(Eq. F-23)}$$

Where:

E_h = Hourly SO_2 mass emission rate, lb/hr.

ER = Applicable SO_2 default emission rate for gaseous fuel combustion, from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, or other default SO_2 emission rate for the combustion of very low sulfur liquid or solid fuel, combinations of such fuels, or mixtures of such fuels with gaseous fuel, as approved by the Administrator under § 75.66, lb/mmBtu.

HI = Hourly heat input rate, determined using the procedures in section 5.2 of this appendix, mmBtu/hr.

8. Procedures for NO_X Mass Emissions

* * * * *

8.1 The own or operator may use the hourly NO_X emission rate and the hourly heat input rate to calculate the NO_X mass emissions in pounds or the NO_X mass emission rate in pounds per hour, (as required by the applicable reporting format), for each unit or stack operating hour, as follows:

8.1.1 If both NO_X emission rate and heat input rate are monitored at the same unit or stack level (e.g., the NO_X emission rate value and the heat input rate value both represent all of the units exhausting to the common stack), then (as required by the applicable reporting format) either:

(a) Use Equation F–24 to calculate the hourly NO_X mass emissions (lb).

$$M_{(NOx)_h} = ER_{(NOx)_h} HI_h t_h \qquad \text{(Eq. F-24)}$$

Where:

$M_{(NO_X)_h}$ = NO_X mass emissions in lbs for the hour.

$ER_{(NO_X)_h}$ = Hourly average NO_X emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from Method 19 in

appendix A–7 to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_X emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_X emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack; or

(b) Use Equation F–24a to calculate the hourly NO_X mass emission rate (lb/hr).

$$E_{(NOx)_h} = ER_{(NOx)_h} HI_h \qquad \text{(Eq. F-24a)}$$

Where:

$E_{(NOx)h}$ = NO_X mass emissions rate in lbs/hr for the hour.

$ER_{(NOx)h}$ = Hourly average NO_X emission rate for hour h, lb/mmBtu, from section 3 of this appendix, from Method 19 in appendix A–7 to part 60 of this chapter, or from section 3.3 of appendix E to this part. (Include bias-adjusted NO_X emission rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

HI_h = Hourly average heat input rate for hour h, mmBtu/hr. (Include bias-adjusted flow rate values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

* * * * *

8.2 Alternatively, the owner or operator may use the hourly NO_X concentration (as measured by a NO_X concentration monitoring system) and the hourly stack gas volumetric flow rate to calculate the NO_X mass emission rate (lb/hr) for each unit or stack operating hour, in accordance with section 8.2.1 or 8.2.2 of this appendix (as applicable). If the hourly NO_X mass emissions are to be reported in lb, Equation F–26c in section 8.3 of this appendix shall be used to convert the hourly NO_X mass emission rates to hourly NO_X mass emissions (lb).

8.2.1 When the NO_X concentration monitoring system measures on a wet basis, first calculate the hourly NO_X mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F–26a. (Include bias-adjusted flow rate or NO_X concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(NOx)_h} = K\ C_{hw} Q_h \qquad \text{(Eq. F-26a)}$$

Where:

$E_{(NOx)h}$ = NO_X mass emissions rate in lb/hr.

K = 1.194 x 10^{-7} for NO_X, (lb/scf)/ppm.

C_{hw} = Hourly average NO_X concentration during unit operation, wet basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

8.2.2 When NO_X mass emissions are determined using a dry basis NO_X concentration monitoring system and a wet basis flow monitoring system, first calculate hourly NO_X mass emission rate (in lb/hr) during unit (or stack) operation, using Equation F–26b. (Include bias-adjusted flow rate or NO_X concentration values, where the bias-test procedures in appendix A to this part shows a bias-adjustment factor is necessary.)

$$E_{(NO_X)_h} = K\ C_{hd} Q_h \frac{(100 - \%H_2O)}{(100)} \qquad \text{(Eq. F-26b)}$$

Where:

$E_{(NOx)h}$ = NO_X mass emissions rate, lb/hr.

K = 1.194 x 10^{-7} for NO_X, (lb/scf)/ppm.

C_{hd} = Hourly average NO_X concentration during unit operation, dry basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

8.3 When hourly NO_X mass emissions are reported in pounds and are determined using a NO_X concentration monitoring system and a flow monitoring system, calculate NO_X mass emissions (lb) for each unit or stack operating hour by multiplying the hourly NO_X mass emission rate (lb/hr) by the unit operating time for the hour, as follows:

$$M_{(NO_X)_h} = E_h t_h \qquad \text{(Eq. F-26c)}$$

Where:

$M_{(NOx)h}$ = NO_X mass emissions for the hour, lb.

E_h = Hourly NO_X mass emission rate during unit (or stack) operation from Equation F–26a in section 8.2.1 of this appendix or Equation F–26b in section 8.2.2 of this appendix (as applicable), lb/hr.

t_h = Unit operating time or stack operating time (as defined in § 72.2 of this chapter) for hour ''h'', in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

8.4 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_X mass emissions, in tons:

(a) When hourly NO_X mass emissions are reported in lb., use Eq. F–27.

$$M_{(NO_X)_{time\ period}} = \frac{\sum_{h=1}^{p} M(NO_X)_h}{2000} \qquad \text{(Eq. F-27)}$$

Where:

$M_{(NOx)time\ period}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(NOx)h}$ = NO_X mass emissions in lb for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

(b) When hourly NO_X mass emission rate is reported in lb/hr, use Eq. F–27a.

$$M_{(NO_X)_{time\ period}} = \frac{\sum_{h=1}^{p} E_{(NO_X)_h} t_h}{2000} \qquad \text{(Eq. F-27a)}$$

Where:

$M_{(NO_X)_{time\ period}}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$E_{(NO_X)_h}$ = NO_X mass emission rate in lb/hr for the hour.

p = The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

t_h = Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

* * * * *

10. Moisture Determination From Wet and Dry O_2 Readings

If a correction for the stack gas moisture content is required in any of the emissions or heat input calculations described in this appendix, and if the hourly moisture content is determined from wet- and dry-basis O_2 readings, use Equation F–31 to calculate the percent moisture, unless a ''K'' factor or other mathematical algorithm is developed as described in section 6.5.7(a) of appendix A to this part:

$$\%H_2O = \frac{(O_{2d} - O_{2w})}{O_{2d}} \times 100 \qquad \text{(Eq. F-31)}$$

Where:

% H_2O = Hourly average stack gas moisture content, percent H_2O

O_{2d} = Dry-basis hourly average oxygen concentration, percent O_2

O_{2w} = Wet-basis hourly average oxygen concentration, percent O_2

■ 45. Appendix G to Part 75 is amended by:

■ a. Revising section 2.1.2;

■ b. Removing ''D3174–89 'Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal' '' and by adding in its place, ''D3174–00, Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal'' in section 2.2.1; and

■ c. Removing ''D3178–89 (1997), 'Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke' '' and adding in its place ''D5373–02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke'' in section 2.2.2.

The revisions read as follows:

Appendix G to Part 75—Determination of CO_2 Emissions.

* * * * *

2.1.2 Determine the carbon content of each fuel sample using one of the following methods: ASTM D3178–89 (Reapproved 2002) or ASTM D5373–02 (Reapproved 2007) for coal; ASTM D5291–02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, ultimate analysis of oil, or computations based upon ASTM D3238–95 (Reapproved 2000) and either ASTM D2502–92 (Reapproved 1996) or ASTM D2503–92 (Reapproved 1997) for oil; and computations based on ASTM D1945–96 (Reapproved 2001) or ASTM D1946–90 (Reapproved 2006) for gas (all incorporated by reference under § 75.6 of this part).

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■ 46. Appendix K to Part 75 is amended by:

■ a. Removing the words ''(see §§ 75.11(b) and 75.12(b))'' and adding in its place the words ''(see § 75.11(b))'' in section 5;

■ b. Adding a sentence to the end of section 7.2.3;

■ c. Removing the words ''or § 75.12(b)'' and ''or § 75.12,'' from section 7.2.4;

■ d. Revising Table K–1 of section 8; and

■ e. Adding the words ''or in Table K–1'' following the words ''§ 75.15(h)'' in the second sentence of section 11.8.

The revisions and additions read as follows:

Appendix K to Part 75—Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems

* * * * *

7.2.3 * * * The sample flow rate through a sorbent trap monitoring system during any hour (or portion of an hour) in which the unit is not operating shall be zero.

* * * * *

TABLE K–1.—QUALITY ASSURANCE/QUALITY CONTROL CRITERIA FOR SORBENT TRAP MONITORING SYSTEMS

QA/QC test or specification	Acceptance criteria	Frequency	Consequences if not met
Pre-test leak check	≤4% of target sampling rate	Prior to sampling	Sampling shall not commence until the leak check is passed.
Post-test leak check	≤4% of average sampling rate	After sampling	** See *Note*, below.
Ratio of stack gas flow rate to sample flow rate.	No more than 5% of the hourly ratios or 5 hourly ratios (whichever is less restrictive) may deviate from the reference ratio by more than ± 25%.	Every hour throughout data collection period.	** See *Note*, below.
Sorbent trap section 2 breakthrough.	≤5% of Section 1 Hg mass	Every sample	** See *Note*, below.
Paired sorbent trap agreement	≤10% Relative Deviation (RD) if the average concentration is > 1.0 μg/m³. ≤ 20% RD if the average concentration is ≤ 1.0 μg/m³. Results are also acceptable if absolute difference between concentrations from paired traps is ≤ 0.03 μg/m³.	Every sample	Either invalidate the data from the paired traps or report the results from the trap with the higher Hg concentration.
Spike Recovery Study	Average recovery between 85% and 115% for each of the 3 spike concentration levels.	Prior to analyzing field samples and prior to use of new sorbent media.	Field samples shall not be analyzed until the percent recovery criteria has been met
Multipoint analyzer calibration	Each analyzer reading within ± 10% of true value and $r^2 \geq 0.99$.	On the day of analysis, before analyzing any samples.	Recalibrate until successful.

TABLE K–1.—QUALITY ASSURANCE/QUALITY CONTROL CRITERIA FOR SORBENT TRAP MONITORING SYSTEMS—Continued

QA/QC test or specification	Acceptance criteria	Frequency	Consequences if not met
Analysis of independent calibration standard.	Within ± 10% of true value	Following daily calibration, prior to analyzing field samples.	Recalibrate and repeat independent standard analysis until successful.
Spike recovery from section 3 of sorbent trap.	75–125% of spike amount	Every sample	** See *Note*, below.
RATA	RA ≤ 20.0% *or* Mean difference ≤ 1.0 μg/dscm for low emitters.	For initial certification and annually thereafter.	Data from the system are invalidated until a RATA is passed.
Gas flow meter calibration	Calibration factor (Y) within ± 5% of average value from the most recent 3-point calibration.	At three settings prior to initial use and at least quarterly at one setting thereafter. For mass flow meters, initial calibration with stack gas is required.	Recalibrate the meter at three orifice settings to determine a new value of Y.
Temperature sensor calibration	Absolute temperature measured by sensor within ± 1.5% of a reference sensor.	Prior to initial use and at least quarterly thereafter.	Recalibrate. Sensor may not be used until specification is met.
Barometer calibration	Absolute pressure measured by instrument within ± 10 mm Hg of reading with a mercury barometer.	Prior to initial use and at least quarterly thereafter.	Recalibrate. Instrument may not be used until specification is met.

** Note: If both traps fail to meet the acceptance criteria, the data from the pair of traps are invalidated. However, if only one of the paired traps fails to meet this particular acceptance criterion and the other sample meets all of the applicable QA criteria, the results of the valid trap may be used for reporting under this part, provided that the measured Hg concentration is multiplied by a factor of 1.111. When the data from both traps are invalidated and quality-assured data from a certified backup monitoring system, reference method, or approved alternative monitoring system are unavailable, missing data substitution must be used.

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