ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72 and 75

[OAR–2005–0132; FRL–8208–1]

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing rule revisions that would 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 proposed 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 would not impose significant new requirements upon sources with regard to monitoring or quality assurance activities.

DATES: All public comments must be received on or before October 23, 2006.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2005–0132, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- *E-mail: a-and-r-docket@epa.gov.*
- *Fax:* (202) 566–1741.
- *Hand Delivery:* Air and Radiation Docket, Environmental Protection Agency, 1301 Constitution Avenue, NW., Room B–108, Washington, DC 20014. Such deliveries are accepted only during the Docket's normal hours of operation and special arrangements should be made for deliveries of boxed information.
- *Mail:* EPA Docket Center (EPA/DC), Environmental Protection Agency, Mailcode 6102T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460. Please include a total of two copies. We request that a separate copy also be sent to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**).

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2005–0132. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or e-mail. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *http://www.regulations.gov,* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment with a disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. *Docket:* All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air and Radiation Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., 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.

Submitting CBI. Do not submit this information to EPA through *http://www.regulations.gov* or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of the proposed rule is also available on the WWW through the Technology Transfer Network Web site (TTN Web). Following signature, a copy of the proposed 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.

Outline:

I. Detailed Discussion of Proposed 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 2009.

A. Rule Definitions

The proposed changes to Part 72 include adding a definition for ''long-term cold storage'' to mean ''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). *See* Section II.E.4 of this preamble for further discussion.

EPA also proposes to modify the definition of ''capacity factor'' so that the Agency can use the reported maximum hourly gross load, as currently reported in the electronic monitoring plan, to determine whether a unit qualifies for peaking unit status, by recalculating the capacity factor. This is important because the maximum hourly gross load can be greater than the nameplate capacity. Also, when using heat input to define capacity factor, the definition would be revised to refer to maximum rated hourly heat input rate, which is defined in § 72.2.

The proposed changes to § 72.2 would also modify the definition of ''EPA Protocol Gas,'' and add a definition of ''EPA Protocol Gas Verification Program'', to support the proposed calibration gas audit program. EPA is also proposing to expand the definition of ''excepted monitoring system'' to include the sorbent trap and low mass emissions (LME) excepted methodologies for Hg. Finally, today's proposed rule would add definitions of ''Air Emission Testing Body (AETB)'' and ''Qualified Individual'', to support the proposed stack tester accreditation program. See Sections II.H.2 and II.H.3 of this preamble for a discussion of these proposed programs.

B. General Monitoring Provisions

1. Update of Incorporation by Reference (§ 75.6)

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). Changes in § 75.6 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.

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

Today's proposed rule revisions would 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 would allow more representative, yet still conservatively high, SO_2 emissions data to be reported from oil-burning LME units. 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.

Today's proposed rule would also 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. The current rule simply states that 3 years (or 3 ozone seasons, if applicable) of quality-assured CEMS data may be used for this purpose, but it does not specify the acceptable level of QA required.

3. Default Moisture Value for Natural Gas

EPA is proposing to allow gas-fired boilers equipped with CEMS to use default moisture values in lieu of continuously monitoring the stack gas moisture content. Two default values are proposed: 14.0% H_2O under § 75.11(b), and 18.0% H_2O under § 75.12(b). The higher default value would apply only when Equation 19–3, 19–4, or 19–8 (from Method 19 in appendix A of Part 60) is used to determine the NO_X emission rate. These proposed default values are based on supplemental moisture data provided to the Agency in a December 13, 2004 petition from a gas-fired industrial source and moisture data collected during EPA's development of flow rate reference Methods 2F and 2G at two gas-fired facilities. (*See* Docket A–99–14; Items II–A–1 and II–A–7).

EPA selected the 10th and 90th percentile values from these data, rounded to the nearest whole number, as the proposed natural gas default moisture values. The selection of conservative 90th or 10th percentile values from representative moisture data sets is consistent with the approach that the Agency has approved in response to past petition under § 75.66 requesting to use site-specific default moisture values.

4. Expanded Use of Equation F–23

Today's proposed rule would 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. The current rule restricts the use of this equation to units equipped with SO_2 monitors and to hours when only fuel that meets the Part 72 definition of ''pipeline natural gas'' or ''natural gas'' is being combusted. EPA proposes to allow 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.

Section 75.11(e) would be re-titled as ''Special considerations during the combustion of gaseous fuels'', and the introductory text of the section would be revised, so that the section would no longer apply exclusively to units with SO_2 monitors. Rather, it would apply to units that use certified flow rate and diluent gas monitors to quantify heat input. Such units would be required to implement the provisions of either revised § 75.11(e)(1) or revised § 75.11(e)(3) when gaseous fuel is the only fuel combusted in the unit. Section 75.11(e)(2) would be removed and reserved, as the use of Appendix D methodology during gaseous fuel combustion is not appropriate for a unit that uses flow and diluent monitors to measure heat input. This is because only one heat input methodology is allowed for each unit.

Revised § 75.11(e)(1) would expand the use of Equation F–23 beyond natural gas combustion to include the combustion of any gaseous fuel that qualifies for a default SO_2 emission rate under Section 2.3.6(b) of Appendix D. The proposed revisions to § 75.11(e)(3) would be relatively minor. The option to use a certified SO_2 monitor during hours of gaseous fuel combustion would be retained.

A new paragraph (e)(4) would also be added to § 75.11(e). This new provision would allow Equation F–23 to 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. Similar petitions would also be accepted for the combustion of mixtures of these fuels and for the co-firing of these fuels with gaseous fuel.

EPA believes that expanding the use of Equation F–23 will benefit certain units that are subject to the Acid Rain Program or to the SO_2 provisions of the Clean Air Interstate Rule (CAIR). In particular, the requirement to operate and maintain an SO_2 CEMS could be waived for units that burn low-sulfur solid fuels such as wood waste. Also, for units that combust non-traditional gaseous fuels, Equation F–23 would provide an alternative way of quantifying SO_2 mass emissions that does not require either an SO_2 CEMS or a certified fuel flowmeter.

5. Calculation of NO_X Emission Rate—LME Units

According to §§ 75.58(f), 75.64(a)(4), and 75.64(a)(9), oil and gas-fired units in the Acid Rain Program that qualify to use the low mass emissions (LME) methodology in § 75.19 are required to report both NO_X mass emissions (lb or tons, as applicable) and NO_X emission rate (lb/mmBtu) on an hourly, quarterly and annual basis. However, the mathematics in § 75.19(c)(4)(ii) pertains only to NO_X mass emissions, not NO_X emission rate. This is most likely because the criterion for initial and on-going LME qualification is based on the total tons of NO_X emitted the calendar year, rather than on the NO_X emission rate.

Today's rule would re-title § 75.19(c)(4)(ii) as ''NO_X mass emissions and NO_X emission rate'', and would add a new subparagraph (D) to § 75.19 (c)(4)(ii), providing instructions for determining quarterly and cumulative NO_X emission rates for an 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. 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.

6. LME Units—Scope of Applicability

Today's rule would 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 would be 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 would be permitted. For example, the owner or operator of a qualifying LME unit in the Acid Rain Program would either be required to follow the provisions of § 75.19 for all parameters (*i.e.*, SO_2 and CO_2 mass emissions, NO_X emission rate, and unit heat input) or to monitor these parameters using a CEMS, Appendices D, E, and G, or a combination of these other methods. EPA has always intended for the LME methodology to be applied this way, but this was not explicitly stated in § 75.19 and in other sections of the rule. In fact, §§ 75.11(d)(3), 75.12(e)(3), and 75.13(d)(3)) suggest that mixing other monitoring methodologies with LME might not be prohibited. Today's rule would also make parallel revisions to these other sections, consistent with the changes to § 75.19(a)(1), to clarify the Agency's intent.

7. Use of maximum controlled NO_X emission rate when using bypass stacks

Today's proposed rule would revise § 75.17(d)(2) to allow for the calculation and use of a maximum controlled NO_X emission rate (MCR) 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. 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). EPA believes that this proposal would more fairly account for controlled emissions when unmonitored bypass stacks are used. The rule currently requires the use of the MER regardless of the operation and usage of add-on controls. When § 75.17(d)(2) was originally promulgated, EPA assumed that the add-on controls would be bypassed whenever a bypass stack is used. EPA is now aware that there are situations where this is not the case. An example would be 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 MEC, rather than the MER, would be the more appropriate NO_X emission rate to report for the bypass hour(s).

C. Certification Requirements

1. Alternative Monitoring System Certification

The proposed rule would 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 that alternative monitoring systems must meet in order to be certified.

2. Part 60 Reference Test Methods

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). Today's proposed rule would update, (as necessary), various section references to these reference methods, as well as specify certain options that are not to be applied to RATA testing under Part 75. Specifically, the following provisions are not permitted unless specific approval is granted by the Administrator of Part 75:

(1) § 7.1 of the revised EPA Method 7E allowing for use of prepared calibration gas mixtures that are produced in accordance with Method 205 in Appendix M of 40 CFR Part 51. EPA maintains that for RATA testing under Part 75, that reference gases be selected in accordance with § 5.1 of Appendix A of 40 CFR Part 75.

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

(3) § 8.6 of the revised EPA Method 7E allowing for the use of ''Dynamic Spiking'' as an alternative to the interference and system bias checks of the method. This proposed rule would allow for dynamic spiking to be conducted (optionally) as an additional quality assurance check for Part 75 applications.

3. Mercury Reference Methods

Today's proposed rule would add an alternative acceptance criterion for the results of mercury (Hg) emission data collected with the Ontario Hydro (OH) reference method and would allow the use of alternative reference methods for RATAs and for the low mass Hg emission testing described in § 75.81(c).

On May 18, 2005, EPA published the Clean Air Mercury Rule (CAMR). That rule requires coal-fired electric generating units (EGUs) to reduce Hg emissions, starting in 2010, and to continuously monitor Hg mass emissions according to Subpart I of Part 75, beginning in 2009.

Relative accuracy test audits (RATAs) of all continuous Hg monitoring systems are required under CAMR, and Hg emission testing is required for units seeking to qualify as low mass emitters under § 75.81(c). The principal reference method specified for the RATAs and the emission testing is the OH method. Alternatively, an instrumental method approved by the Administrator may be used. When the OH method is performed, § 75.22(a)(7) requires paired sampling trains for each test run, and the relative deviation (RD) of the results from the two trains must not exceed 10 percent.

As part of the May 18, 2005 rulemaking, EPA also promulgated revisions to Subpart Da of the New Source Performance Standards (NSPS) regulations, requiring continuous Hg emission monitoring for new coal-fired electric utility units constructed after January 1, 2004. Along with the Subpart Da revisions, a performance specification, PS–12A, for certifying the required continuous Hg monitors was published. PS–12A, like Part 75, requires RATA testing of all Hg monitoring systems, using paired reference method sampling trains; however, note that PS 12–A allows EPA Method 29 (from Appendix A–8 of 40 CFR Part 60) to be used as an alternative to the OH method, whereas Part 75 does not.

The principal acceptance criterion in Section 8.6.6.2 of PS 12–A for the data from the paired reference method trains (10 percent RD) is the same as in § 75.22(a)(7). However, PS 12–A includes an alternative acceptance criterion for sources with low Hg emissions. If the average Hg concentration during the RATA is 1.0 $\mu g/m^3$ or less, the RD specification is 20 percent. In view of this, today's proposed rule would revise § 75.22(a)(7), to include this same 20 percent alternative RD specification for low-emitters. This would harmonize the Part 60 and Part 75 RATA provisions for Hg monitors, thereby facilitating compliance for sources subject to both sets of regulations.

EPA is also proposing revisions to §§ 75.22(a)(7) and 75.81(c)(1) which would allow EPA Method 29 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). Method 29 is an established test procedure that uses atomic absorption spectroscopy to determine the concentration of various metals, including Hg, in the stack gas. This method is more familiar to emission testers than the OH method, and Method 29 data have been accepted for compliance purposes by the State. Method 29 and the OH method both measure the total vapor phase Hg in the effluent. The main difference between the two methods is that the OH method performs ''speciation'' of the vapor phase Hg, *i.e.*, it quantifies the elemental and ionic portions of the vapor phase Hg separately, whereas Method 29 does not. However, the CAMR rule does not require speciation of the vapor phase Hg. Therefore, Method 29 could be used instead of the OH method.

There would be two caveats on the use of Method 29. First, sources electing to use Method 29 would be required to use paired sampling trains (*i.e.*, two trains sampling the source effluent simultaneously), and the relative deviation specification in § 75.22(a)(7) would have to be met for each run. The test results for each valid run would be based on the Hg collected in the back half of each sampling train (*i.e.*, the impinger catch), and the results from the two trains would be averaged arithmetically.

Second, certain analytical and QA procedures in the OH method (ASTM D6784–02) would be followed instead of the corresponding procedures in Method 29. Specifically, testers would be required to replace the procedures in sections 7.5.33 and 11.1.3 of Method 29 with the corresponding procedures in sections 13.4.1.1 through 13.4.1.3 of ASTM D6784–02, and to perform the QA/QC procedures in section 13.4.2 of the OH method instead of the procedures in section 9.2.3 of Method 29. EPA believes that implementing these sections of the OH method in lieu of the corresponding Method 29 provisions will improve the quality of the data, because the analytical and QA/QC requirements of the OH method are more detailed and rigorous than those in Method 29.

EPA is also proposing to allow several of the sample recovery and preparation procedures in the OH method to be followed instead of the Method 29 procedures. In particular: (a) Sections 13.2.9.1 through 13.2.9.3 of the OH method could be followed instead of sections 8.2.8 and 8.2.9.1 of RM 29; (b) sections 13.2.10.1 through 13.2.10.4 of the OH method could be followed instead of sections 8.2.9.2 and 8.2.9.3 of RM 29; (c) section 8.3.4 of RM 29 could be replaced with section 13.3.4 or 13.3.6 of the OH method (as appropriate); and (d) section 8.3.5 of RM 29 could be replaced with section 13.3.5 or 13.3.6 of the OH method (as appropriate). Use of these alternative procedures would increase the accuracy of moisture content determinations (by using a gravimetric rather than a volumetric technique), and would eliminate of the need for two separate analyses of the $KMnO_4$ fraction.

Revisions to § 75.59 and to Sections 6.5.10 and 7.6.1 of Appendix A to Part 75 are also being proposed, for purposes of consistency with the proposed changes to §§ 75.22(a)(7) and 75.81(c)(1).

Finally, the Agency is soliciting comment on the use of sorbent traps for reference method testing. At the 2006 Electric Utility Environmental Conference (EUEC) in Tucson, Arizona, a stakeholder meeting was held to discuss mercury monitoring issues. Many of the participants expressed an interest in using portable sorbent trap monitoring systems for Hg reference method testing, as an alternative to the OH method. After much internal discussion, EPA believes that a sorbent trap system could potentially serve as an alternative reference method for Hg emission testing and RATA applications, if it can be adequately demonstrated that the method does not have an inherent measurement bias when compared to the OH method, and if sufficiently rigorous quality-assurance (QA) procedures are developed and followed when the system is used in the field. In view of this, EPA requests comment on how such a demonstration might be made and what QA procedures would be appropriate. In anticipation that a viable reference method using sorbent trap technology may be developed in the near future, the Agency is also proposing to add language to § 75.22(a)(7), which would allow an ''other suitable'' reference method approved by the Administrator to be used for Hg emission testing and RATAs.

D. Missing Data Substitution

1. Block Versus Step-Wise Approach

During periods of missing CEMS data, Part 75 requires substitute data to be reported. Special mathematical algorithms are used to determine the appropriate substitute data values. As the length of a missing data period increases, the percent monitor data availability (PMA) decreases, and the required substitute data values become increasingly conservative each time that a particular PMA ''cut point'' is reached. The cut points are 95%, 90%, and 80% PMA for all parameters except Hg. For Hg, the cut points are slightly lower, *i.e.*, at 90%, 80% and 70% PMA.

Historically, EPA's policy has required sources to use a ''block'' approach for missing data substitution. The 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 revised its missing substitution data policy. The revised policy guidance (*see* ''Part 75 Emission Monitoring Policy Manual'', Question 15.5) allows 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.

Part 75 is not clear about which of the two methods should be used for missing data substitution. Today's proposed rule would revise the text of certain paragraphs in §§ 75.33 and 75.32(b), to clarify that the stepwise, hour-by-hour method (which is the least stringent approach) is the preferred one. The Agency favors this approach because it prevents sources from being penalized by the retroactive application of more stringent missing data algorithms to hours where the hourly PMA merits the use of less conservative algorithms. EPA intends that only the new stepwise, hour-by-hour method be used after January 1, 2009, or whenever emissions data are to be submitted in XML–format. Until this time, either method will be accepted.

2. Substitute Data Values for Controlled Units

For units with add-on emission controls, § 75.34(a)(3) provides that the designated representative (DR) may petition the Administrator under § 75.66 to report alternative substitute data values in certain instances. Specifically, when the percent monitor data availability (PMA) for SO_2 or NO_X is below 90.0 percent, the DR may petition to replace the maximum emission rate recorded in the last 720 quality-assured monitor operating hours with the maximum controlled emission rate recorded during that same lookback period, for each missing data hour in which the add-on controls are documented to be operating properly. Until recently, this petition provision applied only to units with add-on SO_2 or NO_X emission controls. However, revisions to Part 75 on May 18, 2005, extended it to include units with add-on Hg controls (*see* § 75.38(c)).

For several reasons, EPA believes it is appropriate to revise § 75.34(a)(3). First, the 720 hour lookback is only appropriate for SO_2 and Hg. For NO_X, the lookback should be 2,160 hours and should also be load-based. Second, for SO_2, Hg, and NO_X concentration monitoring systems, the terms ''maximum emission rate'' and ''maximum controlled emission rate'' are not appropriate and should be replaced by ''maximum concentration'' and ''maximum controlled concentration'', respectively. Third, the petition provision, as written, applies to all PMA values below 90.0 percent (that was the intent when it was originally written), but in light of subsequent revisions to Part 75, it should be restricted to a narrower range of PMA values. Fourth, and most important, after more than ten years of implementing the Acid Rain Program, EPA no longer believes that special petitions are necessary to use maximum controlled values for missing data substitution, 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.

At the time the petition provision in § 75.34(a)(3) was written, there were only three missing data tiers in existence, *i.e.*, for PMA values: (1) ≥ 95.0 percent; (2) ≥ 90.0 percent, but < 95.0 percent: and (3) < 90.0 percent. The provision was associated with the third tier (PMA < 90.0 percent), for which the required substitute data value is the maximum value recorded in a specified lookback period. However, on May 26, 1999, EPA added a fourth CEMS missing data tier to Part 75. The May 1999 rule revisions did not change the missing data algorithms for the third tier, but the PMA ''cut off'' point for the third tier was set at 80.0 percent, and below 80.0 percent PMA, reporting of the maximum potential concentration (MPC) or the maximum potential NO_X emission rate (MER) was required for a missing data period of any length.

Today's proposed rule would 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 is also proposing 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 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 (*see* Appendix A, section 2.1.2.1(b)), except that the MEC, rather than the MPC, would be used in the calculation.

Finally, today's proposed rule would 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).

EPA believes that for missing data hours in which the emission controls are working properly, these proposed rule revisions will prevent gross overestimation of emissions during hours when the source is operating its emission controls in a manner that is protective of the environment. When the emission controls are working properly, there can be as much as a tenfold difference between the MPC, MER, or maximum value in a lookback period and the actual source emissions. The proposed alternative substitute data values in §§ 75.34(a)(3) and (a)(5), though much closer to the actual emissions, would still be conservatively high and would provide the owner or operator with a strong incentive to keep the CEMS operational. The Agency also believes that the proposed alternative data substitution methodology in § 75.34(a)(5) ensures that the substitute data values for the fourth tier will always be higher than the corresponding substitute data values for the third tier.

3. Substitute Data Values for Hg

EPA is also proposing to revise the Hg missing data procedures. First, for Hg CEMS, the text of § 75.38(a) would be amended to make it consistent with Table 1 in § 75.33. Proposed § 75.38(a) clarifies that the percent monitor data availability (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 proposes to completely revise the missing data provisions in § 75.39 for sorbent trap monitoring systems. In the current rule, the missing data routines for sorbent trap systems are substantially different from those for Hg CEMS. At the time of publication of the Part 75 Hg monitoring provisions, the Agency believed that a different approach to missing data substitution was appropriate for sorbent traps, because unlike the Hg CEMS, a sorbent trap system does not provide real-time hourly average emissions data. Consequently, EPA prescribed a 12-month missing data ''lookback'' period for the sorbent trap systems. That is, the substitute data values are based on a lookback through the previous 12 months of sorbent trap sample results, instead of looking back through 720 quality-assured monitor operating hours, as is done for the Hg CEMS.

EPA has reconsidered the sorbent trap missing data methodology and has concluded that it is unnecessarily complex and will likely be difficult to implement and audit. In view of this, the Agency proposes to amend the missing data procedures for sorbent trap systems, to make them the same as for Hg CEMS. Section 75.39 would be revised to require that the initial missing data procedures of § 75.31(b) and the standard Hg missing data provisions of § 75.38 be followed for sorbent trap systems. EPA believes that this missing data approach can work because for the purposes of Part 75 reporting, the average Hg concentration measured by a sorbent trap system is ''back-filled'' into each hour of the data collection period to simulate hour-by-hour concentration measurements (*see* § 75.57(j)(1)(iii)). Thus, 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, the required missing data lookbacks through 720 hours of quality-assured data could be done on the sorbent trap data stream, although in some cases, because of the flat-line effect, when the 720 hours of data are arranged in rank order, the 90th percentile, 95th percentile, and maximum values in the lookback might be identical.

Finally, a new paragraph ''(f)'' would be added to § 75.39 to address the case in which the owner or operator elects to use a primary Hg CEMS and a redundant backup sorbent trap system (or vice-versa). In that case, separate Hg concentration data streams would be recorded and maintained for the two systems. For reporting purposes, data from the primary monitoring system would be reported whenever that system is able to provide quality-assured data (*see* § 75.10(e)), and quality-assured data from the redundant backup system (if available) could be reported during primary monitoring system outages. However, when both the primary and redundant backup monitoring systems are down and quality-assured data from a reference method or approved alternative monitoring system are also unavailable, proposed § 75.39(f) would require the appropriate substitute data values to be derived from a lookback through the previous 720 hours of quality-assured data reported in the electronic quarterly report, irrespective of the source of those data, *i.e.*, whether they were from the primary system, the redundant backup system, a reference method, or an approved alternative monitoring system.

4. Correction of Cross-References

For sources in the NO_X Budget Program that report emissions data only during the ozone season (*i.e.*, May through September), the quality assurance requirements for the continuous emission monitoring systems are found in § 75.74(c). In §§ 75.74(c)(3)(xi) and (c)(3)(xii), data validation rules are provided for situations in which required quality-assurance tests of the CEMS are due by the end of the second or third calendar quarter, but are not completed on time. In some cases, these rule provisions require the use of missing data substitution, and refer to the ''appropriate missing data routine in § 75.31, § 75.33 or § 75.37''. These references to specific missing data sections are inadequate, because they only cover initial missing data (for all parameters) and the standard missing data procedures for NO_X , flow rate, and moisture. Sections 75.34 through 75.36 are not referenced, which address missing data substitution for units with add-on emission controls and for diluent gas (O_2 or CO_2) data used for heat input rate determination. Many NO_X Budget Program units are equipped with add-on NO_X emission controls, and a great number use data from a CO_2 or O_2 monitor to determine the hourly heat input rate. In view of this, today's rule would revise §§ 75.74(c)(3)(xi) and (c)(3)(xii) by replacing each of the cross-references to specific missing data sections with a more general reference to the entire block of CEMS missing data sections, *i.e.*, §§ 75.31 through 75.37.

E. Recordkeeping and Reporting

1. Revisions to the General Monitoring Plan Recordkeeping Requirements

EPA proposes to revise the monitoring plan recordkeeping requirements in § 75.53, to accommodate its new, re-engineered XML reporting format, which will replace the current electronic data reporting (EDR) format in 2009. The Subpart H monitoring plan record keeping provisions in § 75.73(c)(3) (for sources reporting NO_X mass emissions) and the Subpart I monitoring plan record keeping provisions in § 75.84 (for sources reporting Hg mass emissions) would be similarly revised to reflect the transition to XML format.

EPA proposes 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. Proposed § 75.53(a)(1) would require all affected units to follow the provisions of paragraphs (g) and (h) instead of the existing recordkeeping requirements of paragraphs (e) and (f), on and after January 1, 2009. However, early implementation of the XML format would be allowed or, in some cases, required. In 2008, existing sources would be allowed to choose between the EDR format and XML, and new sources reporting for the first time in 2008 would be required to use XML.

Table 1 summarizes the data elements or requirements in § 75.53 that would be removed, replaced or added as a result of transitioning from the current EDR to XML EDR format.

TABLE 1.—MONITORING PLAN CHANGES ASSOCIATED WITH XML FORMAT

Data element(s) or requirement(s)	Proposed action(s)	Comments
• Facility short name • Unit program classification • Unit boiler type • Date of commence operation (Subpart H units) • Date of commence commercial operation (Acid Rain units) • Unit retirement date • Program code • Reporting frequency • Program participation date • State regulation code • State or local agency code • EIA cross-reference information.	Remove	These data elements would be collected and maintained through the Certificate of Representation form, the CAMD Business System, or internally by EPA.
• Recording and reporting of information associated with monitoring system certification, recertification, and other events.	Relocate	Relocate the requirement to record and report this information to § 75.59, the quality-assurance recordkeeping section.
• Fuel classification for boiler • Primary/secondary control indicator • Type of fuel associated with each monitoring methodology • Primary/secondary methodology indicator • Appendix E correlation curve segment data.	Remove	These data elements are deemed unnecessary for the new XML reporting format.

TABLE 1.—MONITORING PLAN CHANGES ASSOCIATED WITH XML FORMAT—Continued

Data element(s) or requirement(s)	Proposed action(s)	Comments
• Component status • Formula status • Submission status of fuel flowmeter data.	Replace	In § 75.53(g), use activation date/hour and deactivation date/hour instead of status codes to better track updates to monitoring components, formulas, and fuel flowmeter information.
• Indicator of exemption from multi-load flow RATAs • Shape of stack or duct cross-section • Stack/duct material of construction • Flag to indicate that a monitored location is a duct • Indicator of non-load based units.	Add	These new data elements are needed to properly assess specific Part 75 quality assurance/quality control (QA/QC) requirements and exemptions.
• Analyzer range code • Moisture measurement basis.	Add	Provide the measurement range (high, low, dual) and moisture basis (wet or dry) for each CEMS component type (SO_2, NO_X, CO_2, etc.)
• Provide the monitoring methodologies for each individual unit. • Represent bypass stack monitoring as a separate methodology.	Replace	For each parameter, associate the monitoring methodology with the monitored lcoation (unit, stack or duct). Integrate bypass stack monitoring with other methodologies. Only one monitoring methodology per paramter would be allowed.
• For dual-range applications, indicate the trigger point at which the component switches from the normal measurement scale to the secondary scale.	Add	Many times data begin to be recorded on the high scale at a certain ''trigger point'', before the full-scale of the low range is reached. EPA needs this information to determine when certain QA tests of the high-scale are required.
• Require operating range and normal load information to be reported for units with CEMS and units using optional fuel flow-to-load ratio test.	Revise	In § 75.53(g), require operating range and maximum load information for all affected units. Require normal load determination for all except peaking units. Separate the date of historical load analysis from activation date of the operating range and load information.
• Duct width at test section • Duct depth at test section • WAF • Method of determining WAF • WAF effective date and hour • WAF no longer effective date and hour • WAF determination date • Number of WAF test runs • Number of Method 1 traverse points in WAF test • Number of test ports in WAF test • Number of Method 1 traverse points in reference flow RATA.	Add	Add data elements to § 75.53(e) and (g), describing monitoring plan requirements for units with rectangular ducts that apply a wall effects adjustment factor (WAF) to their flow rate data. (*See* Section II.E.2 for further discussion.)

2. Discussion of Wall Effects Adjustment Requirements for Rectangular Ducts

In 1999, EPA published a new reference method, Method 2H, in Appendix A of 40 CFR Part 60. Method 2H allows the owner or operator of a unit with an installed flow monitor to correct the measured gas flow rates for velocity decay near the stack wall (*i.e.,* ''wall effects''). Applying Method 2H greatly reduces the possibility of over-reporting SO_2 and NO_X mass emissions, which are directly proportional to the stack flow rate. However, Method 2H applies only to circular stacks. Consequently, Acid Rain and NO_X Budget Program units with flow monitors installed on rectangular stacks or ducts (estimated at about 10 percent of the affected units with flow monitors) were unable to benefit from the use of a wall effects adjustment factor (WAF).

To remedy this situation, a wall effects correction method for rectangular stacks and ducts was developed. The method, known as CTM–041, has been adopted as a conditional test method by EPA. A conditional test method differs from a reference method in that it is not in the Code of Federal Regulations, but it is recognized as having technical merit. Sources interested in using a conditional method in a particular program must obtain permission from the regulatory agency administering the program.

Since 2004, when CTM–041 was adopted as a conditional EPA test method, many Acid Rain and NO_X Budget Program sources have requested (and received) permission from EPA to use it for Part 75 monitoring. As a condition of these approvals, the sources were asked to report the essential wall effects information in their quarterly electronic data reports (EDRs). However, EPA had not developed the necessary electronic record types (RTs) to accommodate the rectangular duct WAF information. Therefore, the Agency issued guidance, instructing the sources to use existing EDR record type 910 to report the WAF data. But record 910, unlike the other EDR record types, has no fixed data elements or fields. This created problems when the WAF information began to be reported. Even though detailed examples were provided in the EPA guidance, a significant portion of the WAF data were being entered into the wrong columns of the 910 records, making it difficult to perform electronic audits of the information.

In view of this, EPA created two new EDR record types, RT 532 and RT 617, to handle the rectangular duct WAF data. Record type 532, which is a monitoring plan record, summarizes the results of each WAF determination. Record type 617 is a quality-assurance record and is submitted along with the results of each flow RATA performed at a rectangular stack or duct, when EPA Method 2 is used and a wall effects correction is applied.

The Agency provided a mechanism (the ''Monitoring Data Checking'' (MDC) Software) by which a source could create the new EDR records and add them to the quarterly report, without having to upgrade the data acquisition and handling system (DAHS). To date, use of the new record types has been voluntary, and the affected sources have been cooperative. Nevertheless, today's rule would make mandatory the recording and reporting of the key rectangular duct WAF data elements using these record types. The proposed requirements to record and report the results of the WAF determinations in the monitoring plan are found in §§ 75.53(e) and (g) and in § 75.64. For a discussion of the proposed requirement to record and report the RATA support data, see Section II.E.5.k, below.

3. Revisions to General Recordkeeping Provisions for Specific Situations

Today's proposed rule would make a series of modifications to § 75.58 to support the new XML data structure. These are summarized in Table 2.

TABLE 2.—PROPOSED CHANGES TO THE GENERAL RECORDKEEPING REQUIREMENTS IN § 75.58

Data element(s) or requirement(s)	Proposed action(s)	Comments
• For Appendix D units, report ID numbers of formulas used to calculate SO_2 mass emissions and heat input rate.	Add to § 75.58(c)	This would be required on and after January 1, 2009.
• For Appendix E units, report the heat input rate formula ID for each unit operating hour.	Add to § 75.58(d)	This would be required on and after January 1, 2009.
• For LME units that combust more than one type of fuel, report the fuel type that produces the highest NO_X emission rate.	Revise § 75.58(f)	Report the fuel type that produces the highest emission rate for each parameter individually (*i.e.,* for SO_2, NO_X, and CO_2, as applicable).
• For LME units under § 75.19(c)(1)(iv)(C)(9), indicate whether unit is operating at base or peak load, each hour.	Add to § 75.58(f)	This flag is needed to ensure that the proper NO_X emission factor is being applied.
• For LME units, flag each hour in which multiple fuels are combusted.	Add to § 75.58(f)	This flag is needed to ensure that the proper emission factors are used for multiple-fuel hours.
• For LME units using long-term fuel flow, report the component and system ID codes.	Revise § 75.58(f)	Require only the system ID. Long-term fuel flow systems have only one component.

4. Proposed Revisions to the QA/QC Recordkeeping Provisions

EPA is proposing to make a series of revisions and additions to the quality assurance and quality control recordkeeping provisions in § 75.59, in support of the XML data format. These are summarized in Table 3.

TABLE 3.—PROPOSED CHANGES TO THE QA/QC RECORDKEEPING PROVISIONS OF § 75.59

Data element(s) or requirement(s)	Proposed action(s)	Comments
• Describe each recertification event, and the date and type of each recertification test.	Revise § 75.59(a)(8)	Expand to include events that require certification and diagnostic testing. Add requirement to report conditional data validation begin date (if applicable). Corresponds to current EDR record type 556.
• Record component and system ID codes for daily calibrations, 7-day calibration error tests, cycle time tests, linearity checks, flow monitor leak checks and interference tests, and fuel flowmeter accuracy tests.	Revise §§ 75.59(a) and (b)	Require only the component ID for these tests. This requirement would be effective on and after January 1, 2009. The cycle time test for NO_X-diluent systems would be simplified.
• Record the test number and reason for test, for daily calibrations and 7-day calibration error tests.	Revise § 75.59(a)(1)(viii)	Clarify that test number and reason for test code apply only to 7-day calibration error tests, not to daily calibrations.
• Report the span value with the results of each linearity check.	Remove from § 75.59(a)(3)(ii)	The span value in the monitoring plan records will be used to evaluate the linearity checks.
• Provide an on-line or off-line indicator flag for all calibration error tests.	Add to § 75.59(a)(1)	This flag is needed to properly assess the hour-by-hour quality-assurance status of CEMS following calibration error tests.
• For flow-to-load tests of multiple stack configurations, indicate whether separate reference ratios are calculated for each stack.	Add, as § 75.59(a)(4)(vii)(M)	This addition is needed for consistency with the flow-to-load test reporting instructions (current EDR record type 605).
• Report sufficient information to validate all grace period claims.	Remove and reserve § 75.59(a)(12)(iii).	EPA's checking software no longer needs this information to evaluate grace periods.
• Record the component and system ID codes for each fuel flow-to-load ratio test.	Revise § 75.59(b)(4)(i)(A)	On and after January 1, 2009, record only the system ID for these tests.
• Report Appendix E correlation curve test data on a monitoring system basis.	Revise § 75.59(b)(5)	On and after January 1, 2009, report this data on a component basis.
• Report the type(s) of fuel(s) combusted during each run of an Appendix E correlation curve test.	Remove § 75.59(b)(5)(i)(H)	This information is not needed in the new XML format and would not be reported after December 31, 2008.
• Report the monitoring system ID code with reference fuel flow-to-load ratio test data.	Add, as § 75.59(b)(4)(ii)(N)	This requirement is consistent with the reporting instructions for the reference fuel flow-to-load ratio (current EDR record type 629).

TABLE 3.—PROPOSED CHANGES TO THE QA/QC RECORDKEEPING PROVISIONS OF § 75.59—Continued

Data element(s) or requirement(s)	Proposed action(s)	Comments
• For LME units, indicate which test runs are used to calculate fuel-and-unit-specific NO_X emission rates.	Add, as § 75.59(d)(1)(xiii)	This requirement is consistent with the reporting instructions for NO_X emission testing of LME units (current EDR version 2.2, record type 650).
• For LME units, multiply the tested NO_X emission rate by 1.15, if applicable.	Revise § 75.59(d)(2)(iii) and add new §§ 75.59(d)(2)(vi) and (vii).	This requirement applies only to turbines that operate only at base or peak load. Consistent with the reporting instructions (current EDR version 2.2, record type 650), reporting of an hourly base or peak load indicator and the default NO_X emission rate for peak load operation would be required.
• Record the date and hour of completion of all required DAHS verifications, whether for initial certification, recertification, or other events.	Add § 75.59(f)	This requirement would be effective on and after January 1, 2009. EPA needs this information to properly establish provisional certification or recertification dates. Proposed changes to § 75.63(a)(2)(iii) would allow this information to be reported electronically as part of the certification or recertification application.
• Record the appropriate reference method data elements for Hg emission tests of low-emitting units.	Add § 75.59(e)	For periodic testing of low mass emission units, recording of the reference method data elements in either § 75.59(a)(7)(vii), (viii), or (x) would be required, depending on which reference method is used for the testing.
• Monitoring system ID • Test number • Operating level • RATA end date and time • Number of Method 1 traverse points • Wall effects adjustment factor	Add, as § 75.59(a)(7)(ix)	Recording of certain data elements and test results would be required for units with rectangular ducts/stacks that apply a wall effects adjustment factor (WAF) to correct their flow rate data. These data elements would be required for each flow RATA.
• Percent CO_2 and O_2 in the stack gas, dry basis • Moisture content of the stack gas (percent H_2O) • Average stack gas temperature (°F) • Dry gas volume metered (dscm) • Percent isokinetic • Particulate Hg collected in the front half of the sampling train, corrected for the front-half blank value (µg) • Total vapor phase Hg collected in the back half of the sampling train, corrected for the back-half blank value (µg)	Add, as § 75.59(a)(7)(x)	Recording of certain data elements would be required when using Method 29 for the RATA of a Hg monitoring system. These data elements would be required for each RATA run.

5. Other Reporting Issues

a. Long-Term Cold Storage and Deferred Units

The proposed changes to Part 75 would clarify the issue of ''long-term cold storage (LTCS)''. First, as previously noted, a 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, a new paragraph, (a)(7), would be added to § 75.61. Proposed § 75.61(a)(7) would require the owner or operator to provide notifications when a unit is placed in LTCS and when the unit re-commences operation. Third, § 75.20(b) would be modified to require 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 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. Finally, EPA notes that these proposed LTCS provisions are not intended to apply to periods of non-operation of units that are ''on-call'' and available for dispatch.

EPA also proposes 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 scope of § 75.4(d) would be broadened beyond the Acid Rain Program to include units in a State or Federal pollutant mass emissions reduction program that adopts 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 revisions to §§ 75.4(d) and 75.61(a)(3) are deemed necessary because the CAIR and CAMR rules do not address deferred units.

Revised § 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, 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.

Today's proposed rule would revise the notification requirements of § 75.61(a)(3) to be consistent with the changes to § 75.4(d). For planned unit outages, the owner or operator would be required to provide notice of shutdown at least 21 days prior to the compliance date. For unplanned outages, notice would be provided within 7 days after the shutdown. For both planned and unplanned outages, notice of the date on which the unit is expected to resume operation would be provided at least 21 days prior to that date. Proposed § 75.61(a)(3) also includes provisions to address situations in which there are changes to any of the planned or projected dates.

b. Notice of Initial Certification Deadline

EPA proposes to revise § 75.61(8) 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 and whether the unit is new or newly-affected, this date will be the earlier of 90 unit operating days or 180 calendar days after the unit: (a) Commences commercial operation; (b) commences operation; or (c) becomes an affected unit. 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.

c. Monitoring Plan Submittal Deadline

Today's proposed rule would change 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. This proposed revision would synchronize the initial monitoring plan submittal with the initial test notice (*see* proposed changes to §§ 75.62(a)(1) and (2), §§ 75.73(e)(1) and (2) for Subpart H units, and §§ 75.84(e)(1) and (e)(2) for Subpart I units).

EPA also proposes to remove the requirement in § 75.62(a)(1) that the 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. However, this flexibility would only be available to sources reporting in the new XML–EDR format under the re-engineered data submission process. Until re-engineering of the data systems is complete, EPA will continue to collect and process all electronic monitoring plan data submitted in quarterly reports in the current EDR format.

d. EPA Form 7610–14

For each certification and recertification application, §§ 75.63(a)(1) and (a)(2) require hardcopy EPA form 7610–14 to be submitted to the Administrator along with the certification or recertification test results in EDR format. However, significant upgrades to EPA's data systems have been made in recent years, and Form 7610–14 is no longer needed to process the applications. Therefore, §§ 75.63(a)(1)(i)(A) and (a)(2)(i) would be revised to remove the requirement to submit Form 7610–14 to the Administrator.

e. LME Applications

EPA is proposing to remove the requirement from § 75.63(a)(1)(ii)(A) for a hardcopy LME certification application to be submitted to the Administrator. Only the electronic portion of the application, including the monitoring plan and LME qualification records, would be sent to EPA. The hardcopy portion of the LME application would be sent to the State and to the EPA Regional Office.

f. Reporting Test Data for Diagnostic Events

EPA proposes 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 flexibility in the reporting of diagnostic test results would only be available to sources reporting in the new XML–EDR format under the re-engineered data submission process. Until re-engineering of the data systems is complete, EPA will continue to collect and process all diagnostic test results submitted in quarterly reports in the current EDR format.

g. Modifications to § 75.64

As part of its data systems re-engineering effort, EPA proposes to revise § 75.64(a) to incorporate language describing the transition from the current reporting requirements of paragraphs (a)(1), (a)(2) and (a)(8) through (a)(15) to the new requirements of paragraphs (a)(3) through (a)(15). Note that only the requirements of paragraphs (a)(1) and (a)(2) of the current rule would be replaced, by the requirements of paragraphs (a)(3) through (a)(7). Proposed paragraphs (a)(3) through (a)(7) better describe the separation of the monitoring plan and quality assurance test information from the quarterly emissions report. Current paragraphs (a)(3) through (a)(7) and (a)(9) through (a)(11) would remain unchanged, but would be renumbered as paragraphs (a)(8) through (a)(15). Current paragraph (a)(8) would be removed.

h. Steam Load Reporting

Historically, Part 75 has required units that produce electrical or thermal output to report unit load either in megawatts or in thousands of pounds per hour of steam. Today's proposed rule would add a third option, *i.e.*, to report load 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. Certain units in these programs (*e.g.*, industrial boilers) do not produce electrical output and would have to report thermal output instead. In the current rule, steam load is expressed only in thousands of pounds per hour, which does not provide the necessary thermal output information. EPA therefore proposes to add text to the following sections of Part 75, describing the new thermal output reporting option: §§ 75.16(e)(3), 75.57(b)(3), 75.59(b)(4)(ii); Appendix A, Sections 7.7(a) and 7.7(c); Appendix B, Sections 2.2.5(a) and 2.2.5(a)(2); Appendix D, Sections 2.1.7.1(a), 2.1.7.1(c), 2.1.7.2(a), and 2.1.7.2(c); and Appendix E, Section 2.4.1.

i. Test Notification Requirements—Hg Low Mass Emission Units

Section 75.61(a)(5) of the current rule requires the owner or operator or the designated representative to provide 21-day advance notice for various periodic quality-assurance tests. In particular, this notice 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) for the semiannual or annual relative accuracy tests of CEMS, and for re-tests of both Appendix E peaking units and low mass emissions (LME) units.

Under Subpart I of Part 75, certain low-emitting units covered by 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. Today's proposed rule would expand § 75.61(a)(5) and add corresponding introductory text to § 75.61(a)(1) to require the owner or operator or the designated representative to provide 21 day notice of these periodic Hg emission tests to EPA and to the State.

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

Sections 75.60(b)(6) and (b)(7) of the current rule 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. Today's rule would 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 mercury emission tests required under § 75.81(d)(4) for low-emitting units covered by CAMR. The time frame for submitting these Hg emission test results would be the same as for the RATAs and Appendix E re-tests.

k. Wall Effects Adjustment Factors

As previously discussed in Section II.E.2 of this preamble, today's rule would require sources with flow monitors installed on rectangular stacks or ducts to report the results of wall effects adjustment factor (WAF) determinations in the monitoring plan, whenever Conditional Method CTM–041 is used to adjust the measured stack gas flow rates for the effects of velocity decay near the stack wall.

For sources with flow monitors installed on circular stacks, reporting of wall effects information is currently required when Method 2H is used in conjunction with Method 2, 2F or 2G (*see* §§ 75.64(a)(2)(xiii), 75.73(f)(1)(ii)(K) and 75.84(f)(1)(ii)(I)). The wall effects data elements that must be reported are found in §§ 75.59(a)(7)(ii) and (a)(7)(iii). These data are not reported in the monitoring plan, but 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, today's rule would revise the text of §§ 75.64(a)(2)(xiii), 75.73(f)(1)(ii)(K) and 75.84(f)(1)(ii)(I) and would add RATA support data elements to a new paragraph, (vii), in § 75.59(a)(7). EPA believes that these proposed changes will 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.

F. Subpart H (NO_X Mass Emissions)

1. Subpart H Diluent Monitoring Systems

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''. Today's proposed rule would revise the text of § 75.71(a)(2) accordingly.

2. Identifying a NO_X Mass Methodology

EPA is proposing to revise § 75.72 to clarify that only one NO_X mass emissions methodology may be identified in the monitoring plan at any given time. Designation of primary and secondary NO_X mass calculation methodologies would no longer be allowed. 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.

Although it is possible with the current EDR format to identify multiple methodologies for a parameter, this was intended for ARP applications, not for NO_X mass emission measurement. Multiple methodology records for SO_2 are sometimes necessary when a bypass stack is used. However, as discussed in Section II.E.1 of this preamble, the reporting of monitoring methodologies is being restructured as part of EPA's re-engineering effort. Bypass stack methods are being integrated with other monitoring methods and will no longer be considered stand-alone methodologies.

3. Reporting of Subpart H Facility Information

Consistent with the proposed revisions to § 75.64, EPA proposes 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.

4. Linearity Check Requirements for Ozone Season-Only Reporters

For Subpart H sources that report emissions data on an ozone season-only (OSO) basis, today's proposed rule would 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). Currently, OSO reporters are 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.

Since the beginning of the NO_X Budget Program, there have been a number of instances where sources have performed pre-season linearity checks in April, but have not done the required in-season linearity checks in May or June. In some cases, this has resulted in CEMS out-of-control periods and has required the use of missing data substitution. These sources apparently believed that the April tests were sufficient to satisfy both the pre-season and second quarter linearity check requirements because for year-round reporters, linearity checks are required only once per quarter.

The current rule also requires OSO reporters 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 not well-understood by the affected sources. It is also difficult for the Agency to assess compliance with the provision, since sources are not required to report the results of any off-season calibration error tests done prior to April. Further, when pre-season linearity checks are done several months before the ozone season, the quality of the data at the start of the ozone season is somewhat questionable.

In view of these considerations, today's proposed rule would revise § 75.74(c)(2) to restrict the time period in which pre-season linearity checks may be conducted. EPA proposes to require the pre-season linearity checks to be done in the month of April. All references to performing the pre-season linearity checks at other times would be deleted, along with the requirement to keep the off-season daily calibration error tests in a format suitable for inspection.

Today's proposed rule would also revise § 75.74(c)(2)(i)(D) by removing the conditional grace period provision and adding a cross-reference to proposed § 75.74(c)(3)(ii)(E), which addresses data validation. If the April linearity check is not completed prior to the start of the ozone season, 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. Proposed § 75.74(c)(3)(ii)(E) would allow a probationary calibration error test to be done, to begin a period of conditional data validation. Then, the linearity check would be done ''hands-off'' within a 168 unit operating hour period following the calibration error test. If the linearity check is passed within the allotted time, the conditionally valid data would be considered quality-assured, back to the hour of the probationary calibration error test. If the linearity check is failed, all data from the monitor would be invalidated back to the beginning of the ozone season and would remain invalid until a linearity check is passed. If the linearity check is done after the 168-hour period expires, data validation would be done according to § 75.20(b)(3)(viii), subject to the restrictions of § 75.74(c)(3)(xii).

Today's proposed rule would 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. Related Section 75.74(c)(3)(viii) would be removed and reserved. 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, proposed § 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 the linearity check is performed and passed in the third quarter, before the 168 operating hour window expires, then that 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.

EPA believes that the proposed linearity check schedule for OSO reporters would ensure that the gas monitors' response is linear throughout the ozone season and would simplify the regulation by reducing the number of required linearity checks from three to two (and in some cases, one) per season.

5. RATA Requirements for Ozone Season Only Reporters

For OSO reporters, Part 75 requires, 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. Section 75.74(c)(2)(ii) states that this requirement can be 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. For example, if a RATA was performed inside the ozone season, in the 3rd quarter of last year, the window of data validation for the test would extend through the 3rd quarter of this year, provided that the RATA results show that the CEMS qualifies for an ''annual'' RATA frequency. However, if a ''semiannual'' test frequency is obtained, the data validation window would expire at the end of the first quarter of this year, and the RATA could not be used to validate data in the current ozone season. Therefore, a pre-season RATA would be required.

The rule further requires each CEMS to be operated, calibrated and maintained in the time period extending from the completion of the RATA, through April 30. This means that if the RATA being used for data validation in the current ozone season was performed during the last ozone season, the CEMS would have to be operated, calibrated and maintained for the entire off-season from October 1 through April 30. Compliance with this type of requirement is difficult for EPA to assess, as previously explained in paragraph 4 of this section. Also, 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. If it were discovered during an audit that this O&M requirement had not been met, a facility could incur substantial data loss. Further, if a CEMS is not maintained in a manner consistent with normal operating practices for an extended period of time following a RATA that was done long before the ozone season, the results of that RATA may not be a true indicator of the CEMS data quality at the start of the ozone season.

In view of these considerations, EPA is proposing to restrict the window of time in which pre-season RATAs may be performed. 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. This restriction would prohibit RATAs done in the previous year from being used to validate data in the current ozone season.

Section 75.74(c)(2)(ii)(F) would be revised to address data validation. The proposed data validation rules for RATAs would be similar to those proposed for linearity checks, *i.e.*, a period of conditional data validation (720 operating hours) would be allowed when the pre-season RATA is not completed by the April 30 deadline. Consistent with these revisions, today's proposed rule would delete the data validation and conditional grace period provisions in §§ 75.74(c)(2)(ii)(G) and (c)(2)(ii)(H) and would remove and reserve §§ 75.74(c)(3)(vi), (vii), and (viii).

Note that EPA is not modifying the provisions of § 75.74(c)(3)(xii), which allows the results of required quality assurance tests that are completed early in the fourth quarter, within a window of conditional data validation, to be submitted with the electronic data report for the third quarter. This provision provides sources with a ''last chance'' opportunity to complete the required quality assurance tests before the final ozone season reports for the NO_X Budget program are due.

6. Determining Peaking Status for Ozone Season Only Reporters

EPA proposes 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. This clarification is supported by Question 27.1 in the ''Part 75 Emissions Monitoring Policy Manual''.

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

Today's rule would correct an organizational error in Subpart H of Part 75. Section 75.72(f), which describes ozone season NO_X mass calculations for units using the low mass emission (LME) methodology under § 75.19, would be removed, and its basic content 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.

G. Subpart I (Hg Mass Emissions)

1. Heat Input Provisions for Common and Multiple Stacks

Subpart I of Part 75 provides the basic procedures for monitoring Hg mass emissions and heat input from affected units under CAMR. However, due to an apparent oversight, the heat input monitoring provisions for certain monitoring configurations were inadvertently omitted from the final rule. In particular, the heat input methodology for common stacks shared by affected and non-affected units, and the methodology for multiple stack or duct configurations are missing. Today's rule would 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.

2. Low Mass Emission Alternative

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) allows 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 is implied that the periodic retests for common stack configurations would also have to be done at the unit level. EPA is reconsidering this approach, for two reasons: (1) With respect to the initial certification testing, it appears to be overly restrictive for at least one particular configuration; and (2) the Agency believes that for the retests it may be unnecessarily difficult and costly to implement.

Therefore, with one exception (discussed below), EPA is proposing 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 option, the 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 rule would allow 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. In 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, the only way to measure the controlled Hg concentration from the individual units would be to operate them one at a time rather than concurrently. EPA believes that for many such configurations, this manner of unit operation is abnormal and potentially problematic. Therefore, the revisions to § 75.81(e) would allow both the initial and ongoing low mass emission testing to be done at the common stack in cases where the individual unit effluent gas streams are combined together upstream of a control device that removes Hg 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 be ''normal'', as defined in Section 6.5.2.1 of Appendix A.

Today's proposed rule would also revise § 75.81(c)(1), to clarify the time frame in which to perform the initial certification testing for the low mass emission option. The current 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.

This approach to implementing the low mass emission alternative should work reasonably well, provided that the certification test date is close in time to the compliance date. However 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. It also raises questions about which default emission rate to use for the initial reporting. In view of these considerations, EPA is proposing 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 proposes to amend § 75.81(d)(4) to address the emission testing requirements when the fuel supply is changed. Revised § 75.81(d)(4) would require additional Hg retesting within 720 unit operating hours, following a change in the fuel supply. The results of this retest would be applied retrospectively, back to the time of the fuel switch. Section 75.81(c)(1) would also be revised 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 Agency believes these rule provisions are necessary to ensure that the default Hg concentration used for Part 75 reporting is representative of the fuel being combusted in the unit. However, note that the proposed revisions only address 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. Cases 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, are not addressed. In view of this, EPA also solicits comments and suggestions on how to apply the Hg low mass emitter option in these situations (*i.e.*, what emission testing and reporting requirements might be appropriate).

3. Harmonization of Subpart I With Other Proposed Rule Revisions

Subpart I of Part 75 also contains a recordkeeping and reporting section (§ 75.84). Section 75.84 contains a few stand-alone provisions, but for the most part, it 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.

As discussed in detail in Section E of this preamble, today's rule would make substantial revisions to the monitoring plan, recordkeeping and reporting sections of Part 75, in support of EPA's data systems re-engineering effort. To make Subpart I consistent with these proposed revisions and with the other proposed changes in today's rule, a number of minor adjustments would also be made to the text of §§ 75.84(c)(3), (e)(1), (e)(2), and (f)(1).

H. Appendix A

1. CO_2 Span Values

EPA proposes 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.

2. Protocol Gas Audit Program

EPA is responsible for implementing air quality programs that rely on accurate calibration gases. Under these programs, calibration gases are used to calibrate EPA reference methods which, in turn, are used to perform stack tests or to calibrate installed pollutant continuous emissions monitoring systems (CEMs) that are used by regulated sources to report emissions to EPA. If the reference methods are low by 20%, then emissions may be underreported by 20%. Calibration gases are also used to ensure that ambient air quality analyzers provide accurate results. Accurate calibrations gases are critical in helping to ensure that the Clean Air Act-mandated emission reductions are achieved.

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. These audits had two goals, to provide a quality check for gas vendors and to connect users with gas vendors. One notable result in the most recent five consecutive years of audits is a steady, significant reduction in failure rate of the calibration gases, from about 27% in 1992 down to 5% in 1996. In 2003, EPA conducted a ''surprise'' audit of 14 national specialty gas producers and found that the failure rate had risen to 11%.

Today's proposed rule would require that EPA Protocol Gases being used for 40 CFR Part 75 purposes be obtained from those specialty gas producers who participate in the audit program. Under the proposed rule, only audit participants may market these gas standards as ''EPA Protocol Gases'', although there will be no requirement for participants' audited standards to meet an accuracy acceptance criterion. The costs of the audits will be borne by the gas producers who elect to participate in the audits. Although it may take several years to revise all of the EPA monitoring regulations in 40 CFR Parts 58 and 60, today's proposed rule would ensure that under Part 75, any specialty gas producers who do not participate in the program will not have a price advantage (due to the lack of audit program costs) over those producers who do participate. An EPA-maintained web site will list the participants and the audit results, which will provide calibration gas users with detailed information about the quality of EPA Protocol Gases.

To clarify the calibration gas requirements in section 5.1 of appendix A to this part, a definition for ''specialty gas producer'' has been added to section 72.2. EPA believes that most of the gas standards and reference materials identified in section 5.1 of appendix A of this part are expensive and not used in practice by Part 75 affected units. Therefore, today's proposed rule also deletes several calibration gas options and definitions, and consolidates the remaining calibration gas descriptions under section 5.1 of appendix A to this part.

EPA is also requesting 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 EPA Protocol gases be within 2 percent of the certified tag values.

3. Requirements for Air Emission Testing Bodies

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. When the proper test procedures are not followed, this can adversely affect the quality of the emissions data, and, in some cases, may call into question a unit's compliance with the requirement to hold allowances covering its emissions. In view of this, today's proposed rule would 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. ASTM D7036–04 covers testing and calibration performed using standard methods, non-standard methods and methods developed by the AETB.

Proposed Section 6.1.2 of Appendix A and revisions to Section 2.1 of Appendix E and to Section 1 of Appendix B would make it clear that this requirement applies 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.

ASTM D7036–04 would be incorporated by reference in § 75.6(a)(45), and a definition of ''Air Emission Testing Body'' would be added to § 72.2.

4. Linearity Requirements for Dual-Span Applications

Section 6.2 in Appendix A and Section 2.2 in Appendix B require the owner or operator of affected units with installed gas monitors to perform periodic linearity checks of the monitors. The basic linearity check requirements are to perform the test for initial certification and then, for ongoing quality assurance (QA), to repeat the test quarterly. In the original Part 75 regulations (published on January 11, 1993), there were no exceptions to these requirements.

However, in May 1999, EPA revised the linearity check provisions of Part 75 as follows. First, Section 6.2 of Appendix A was revised to exempt SO_2 and NO_X span values of 30 ppm or less from performing linearity checks. Second, revisions to Section 2.2 of Appendix B reduced the ongoing linearity check requirement from once per calendar quarter to once every ''QA operating quarter'' (*i.e.*, a calendar quarter in which the unit operates for at least 168 hours).

Since the May 1999 revisions became effective, the regulated sources appear to have understood the ''QA operating quarter'' concept in Section 2.2 of Appendix B, but there has been some confusion about the meaning of the linearity exemption in Appendix A. 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. The misunderstanding appears to center around two sentences in Section 6.2. The first sentence states that ''Notwithstanding these requirements, if the SO_2 or NO_X span value for a particular range is $\leq$ 30 ppm, that range is exempted from the linearity test requirements of this part.'' Since the phrase ''of this part'' refers to Part 75, this seems to exempt ranges of 30 ppm or less from all Part 75 linearity requirements, including initial certification and ongoing QA. However, the second sentence states that ''For units using emission controls and other units using both a high and a low span, perform a linearity check on both the low- and high-scales for initial certification.'' Thus, for dual span applications, this statement appears to require linearity checks of both measurement scales for initial certification regardless of the span values, which does not harmonize with the 30 ppm exemption.

EPA believes that the key to understanding and reconciling these rule texts is the chronological order of the two sentences. The second sentence is from the original 1993 rule and the first sentence was added in 1999. Therefore, the 30 ppm linearity check exemption in the first sentence takes precedence over the low scale linearity check requirement of the second, and there is no actual contradiction. However, to eliminate any doubt as to the Agency's intended meaning, today's rule would 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.

5. Dual Span Applications—Data Validation

Today's proposed rule would revise Sections 2.1.1.5 (b)(2) and 2.1.2.5(b)(2) of Appendix A 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. The changes would be consistent with the proposed revisions to Appendix B (*see* Section II.I.3, below).

In the current rule, Sections 2.1.1.5(b)(2) and 2.1.2.5(b)(2) of Appendix A provide instructions for reporting SO_2 and NO_X concentration data when the full-scale range of the monitor is exceeded. For single-range applications, a value of 200 percent of the maximum potential concentration (MPC) must be reported when a full-scale exceedance occurs. For dual range applications, if the low range is exceeded, no special reporting is 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 the MPC must be reported.

EPA believes that for dual range applications, 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'', are too general and do not adequately address the possible scenarios associated with dual range monitoring. Today's rule would 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 have to be reported until the expired high-range test is redone or until the data return to the low scale.

These revisions would clarify that when the low range is up-to-date on its QA tests but the high range is not, the QA statuses of the two ranges are evaluated separately and may be different. However, as explained in greater detail in Section II.I.3, below, the QA statuses of the low and high ranges are not necessarily independent when a calibration error test or a linearity check on one of the ranges is failed.

6. Cycle Time Test—Stability Criteria

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 ''upscale'' portion of the test consists of injecting a zero-level calibration gas, allowing the reading to stabilize, recording it, and then stopping the calibration gas flow, waiting until a stable reading of the source emissions is obtained, and recording it. The ''downscale'' portion of the test is performed in like manner, except that a high-level calibration gas is used instead of the zero-level gas.

Section 6.4 currently specifies criteria for determining when a stable 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 are quite stringent and can be very difficult to meet. For example, if the span value of a NO_X analyzer is 10 ppm and the average measured source emissions are 3 ppm, the source emissions would have to remain constant within about 0.2 ppm for the specified amount of time to meet the stability criteria.

In recent years, hundreds of new combustion turbines (CTs) have been built. The vast majority are subject to Part 75, are equipped with NO_X monitoring systems, and have NO_X permit limits less than 10 ppm. Therefore, the 0.2 ppm cycle time stability criterion in the example above is realistic and applies to many of these new CTs. To provide a measure of relief for these low-emitting sources, today's rule would 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. EPA believes these alternative stability criteria are needed to ensure that minor temporal variations in the concentration of the source effluent do not cause testers to overestimate the amount of time it takes to achieve stable readings, resulting in ''false positive'' failures of the cycle time test.

7. System Integrity and Linearity Checks of Hg CEMS

Subpart I of Part 75 includes certification test procedures and performance specifications for Hg CEMS. 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, states 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 is provided. Today's proposed rule would restructure paragraph (3) of Section 3.2 (as described in the next paragraph) and add the necessary mathematical procedure.

EPA is also proposing to make the linearity and system integrity check specifications for Hg monitors the same. The principal linearity error specification in Section 3.2(3)(i) is currently 10.0 percent of the reference gas tag value at each calibration concentration, when calculated according to Equation A–4. The alternative specification in Section 3.2(3)(ii) allows an absolute difference of up to 1.0 μg/m³ between the average reference gas and monitor values at each calibration gas level. Today's proposed rule would replace the principal linearity error specification with a specification of 5.0 percent of the span value, and would lower the alternative specification to 0.6 μg/m³. Further, the same 0.6 μg/m³ alternative specification would be added to the rule for the system integrity check.

The reason for making these changes is that nearly all Hg monitors are equipped with a converter and measure the total vapor phase Hg (*i.e.*, oxidized plus elemental) as elemental Hg. Therefore, 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. Because the current linearity specifications are less stringent than the specification for the system integrity check, EPA proposes to revise and restructure paragraph (3) in Section 3.2 of Appendix A, to make the performance specifications the same for linearity checks and system integrity checks of Part 75 Hg monitors (this includes both the 3-level and single-level system integrity checks). The alternative performance specification is deemed necessary for low (10 μg/m³ Hg span values, where the principal specification of 5.0% of span may be overly stringent.

8. Correction of Hg Calibration Gas Concentrations for Moisture

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 may be added to the calibration gas. This creates a potential source of error in the calculations, if the Hg monitoring system measures on a dry basis. In view of this, EPA proposes 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 if the Hg monitor measures on a dry basis. The proposed revisions would also require the calibration gas concentration to be converted to a dry basis for purposes of the calibration error calculations.

Parallel language would be added 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. The Agency believes that adoption of these proposed revisions will prevent many ''false positive'' failures of Hg monitor calibration error tests, linearity checks, and system integrity checks.

9. Correction of Cross-References

Today's proposed rule would 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 refers 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. Also, the references in Sections 6.5.6(b)(3) and 6.5.6.3 of Appendix A to Section 3.2 of 40 CFR Part 60, Appendix B, Performance Specification No. 2 (PS2) are incorrect. The correct section number in PS2 is 8.1.3, not 3.2.

I. Appendix B

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

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''. However, as written, the rule actually allows more than five years (20 calendar quarters) to elapse between 3-load flow RATAs. For instance, if a 3-load flow RATA was performed in the1st quarter of 2001 and the next one is done in the 4th quarter of 2006, the rule requirement would be met, but there would be 23 calendar quarters between the successive tests.

In light of this, EPA is proposing 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 the other 5-year testing requirements in Part 75, *i.e.*, for Appendix E and LME units. It is also consistent with the maximum allowable interval between successive accuracy tests of Appendix D fuel flowmeters.

EPA is also proposing to revise the RATA grace period provisions in Section 2.3.3. In recent years many new combustion turbines have been built and most of them have NO_X-diluent CEMS. A great number of these turbines have been operated infrequently due to the high price of natural gas. Because of this, a unit may go for a very long period of time without performing a RATA of the NO_X monitoring system because the unit seldom, if ever, has a ''QA operating quarter'' (so the extended deadline for the next RATA is often 8 calendar quarters from the previous test), and then it may be several quarters or even years before the allowable 720 operating hour grace period expires.

The grace period provisions in Section 2.3.3 were proposed in 1998 and promulgated in May 1999, before the influx of new, infrequently-operated combustion turbines. Consequently, these rule provisions are often very difficult to track and apply to such units. Therefore, EPA proposes to modify the grace period methodology so that it is more understandable and user-friendly, particularly in cases where a unit seldom operates.

Today's proposal would move the requirements for determining the deadline for the next RATA after a grace period test from paragraph (c) of Section 2.3.3 to a new paragraph (d). Paragraph (c) currently addresses both RATA deadlines and the data validation requirements for the case where a RATA is not completed by the end of the 720 operating hour grace period. Creating a new paragraph (d) would make Section 2.3.3 clearer, by treating the RATA deadline requirement as a distinct and separate issue.

Proposed paragraph (d) would change the methodology for determining RATA deadlines without changing the end result. The intent of Section 2.3.3 has 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. For instance, if the source did not return to its original RATA schedule, the grace period could be used to extend the interval between successive annual RATAs from four QA operating quarters to five.

The current language in Section 2.3.3 works well enough for base load units that operate most of the time. For these units, the grace period almost invariably begins and ends within one calendar quarter of the RATA deadline, making it easy to return to the original RATA schedule. For instance, suppose that a base load unit is on a 2nd quarter RATA schedule and a grace period RATA is done in the 3rd quarter. If annual frequency is obtained, the deadline for the next RATA is reckoned from the 2nd quarter, when the RATA was due, rather than the 3rd quarter when the grace period test was actually done. Therefore, the next RATA would be required in the 2nd quarter of the following year, *i.e.,* ''back on schedule''. However, for infrequently operated 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 is proposing a simplified 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 expressed as a certain number of QA operating quarters after the quarter of the grace period RATA, rather than referring back to the quarter in which the RATA was originally due (which could have been several quarters in the past).

The deadline for the next RATA would be determined by first establishing whether the grace period RATA qualifies for the standard (semiannual) RATA frequency or the reduced (annual) frequency. If the grace period RATA does not qualify for the annual frequency, the deadline for the next RATA would be simply set at two QA operating quarters after the quarter of the grace period test. If the RATA qualifies for the annual frequency then the deadline for the next RATA would be set at three QA operating quarters after the quarter of the grace period test. There would be one exception to these rules. Regardless of the number of QA operating quarters that have elapsed following the grace period test, the interval between a grace period RATA and the deadline for the next required RATA could be no greater than eight calendar quarters. This provision is consistent with Section 2.3.1.1(a) of Appendix B.

Finally, EPA is proposing to amend paragraph (c) of Section 2.3.3, to clarify that when a RATA is performed after the expiration of a grace period, the ''clock'' is reset, and the next RATA would simply be due in two QA operating quarters (for semiannual frequency) or four QA operating quarters (for annual frequency), not to exceed eight calendar quarters.

EPA believes that the proposed revisions to Section 2.3.3 of Appendix B would greatly simplify implementation of the grace period provisions and would enhance the Agency's ability to track RATA deadlines and to provide meaningful feedback to the affected sources.

2. RATA Requirement for Shared Components

Today's proposed rule would 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. An example would be a coal-fired source that is subject to both the Acid Rain and NO_X Budget Programs, for which the owner or operator elects to use a NO_X concentration system to quantify NO_X mass emissions, while using the NO_X-diluent system to satisfy the Acid Rain Program requirement to monitor and report NO_X emission rate in lb/mmBtu. In such cases, 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. Successful RATAs of both monitoring systems would be required to get them back in-control.

3. AETB Requirements

Appendix B would be further revised 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.

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

Today's rule would 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).

Section 2.1.1 of Appendix B would be revised to require that sufficient calibration error tests be performed on the low and high monitor ranges to validate the data recorded on each range. The provisions of Section 2.1.5 of Appendix B would be used to determine whether ''sufficient'' calibration error tests have been done. A new paragraph (3) would also be added 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. In the case where 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 has expired, this would have no effect on the QA status of the other range.

In the current rule, Section 2.2.3(e) in Appendix B states that when linearity checks are performed on both scales of a dual-range analyzer, an out-of-control period occurs if either of the two linearity checks is failed or aborted due to a problem with the monitor. However, it is not clear whether only one range or both ranges must be retested to get back in-control. Today's rule would revise Section 2.2.3(e) to require ''hands-off'' linearity checks of both ranges of a dual-range analyzer whenever a linearity check on either range is failed or aborted (unless, of course, a particular range is exempted from linearity checks under Section 6.2 of Appendix A).

5. Off-Line Calibration Error Tests

Part 75 requires calibration error tests of all CEMS to be done while the unit is combusting fuel (*see* Appendix B, Section 2.1.1 and Appendix A, Sections 6.3.1 and 6.3.2). However, 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. Today's rule would 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.

The Agency believes that main reason why there have been so many questions about the use of off-line calibration error tests is that paragraph (2) of Section 2.1.1.2 is not clear. Paragraph (2) states that ''a successful on-line calibration error test of the monitoring system must be completed no later than 26 unit operating hours after each off-line calibration error test used for data validation.'' This statement can be easily misinterpreted. It could be understood to mean that a single off-line calibration error test can be used to validate 26 unit operating hours of data, regardless of the number of clock hours it takes to accumulate the 26 unit operating hours. However, this is not the intended meaning because it would directly contradict the statement, in Section 2.1.5 of Appendix B, that the window of data validation from a passed calibration error test extends for only 26 clock hours.

To clarify EPA's intent regarding the use of off-line calibration error tests to validate CEM data, today's rule would revise Sections 2.1.1.2 and 2.1.5.1 of Appendix B. First, paragraph (2) in Section 2.1.1.2 would be revised to state that sources may make limited use of off-line calibrations if the off-line calibration demonstration has been performed and passed. Revised 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. The sequence of consecutive valid hours would be considered broken whenever a unit operating hour is not contained within the 26 clock hour data validation window of a passed off-line calibration error test.

6. Weekly System Integrity Check—Data Validation

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, Section 2.6 does not explain the consequences of either failing the test or failing to perform the test on schedule. Today's rule would add data validation rules for the weekly system integrity check to Section 2.6 of Appendix B. If the test is failed, it would trigger an out-of-control period until a subsequent system integrity check is passed. Also, 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.

Today's rule would also correct a typographical error in Section 2.6 of Appendix B. The performance specification for the weekly system integrity check is incorrectly referenced in the current rule as Section 3.2 (c)(3) of Appendix A. The correct citation is Appendix A, Section 3.2, paragraph (3)(iii).

7. Correction of Hg Units of Measure—Figure 2

Today's rule would correct a minor error in the units of measure for Hg concentration in Figure 2 of Appendix B. The units of micrograms per dry standard cubic meter (μg/dscm) would be changed to micrograms per standard cubic meter (μg/scm). This change is necessary because not all Hg monitoring systems measure Hg concentration on a dry basis.

J. Appendix D

1. Update of Incorporation by Reference

As discussed in Section II.B.1of this preamble, EPA proposes to update the list of test methods, sampling and analysis procedures, and other items that are incorporated by reference in Part 75. As such, this proposal also includes the necessary updates to the references in Appendix D.

EPA is also proposing 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.

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

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 in the monitoring plan for the unit 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, 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, each one must meet the 0.5 gr/100 scf total sulfur limit.

The criteria for documenting the total sulfur content of PNG were promulgated on June 12, 2002, and the annual total sulfur requirement became effective on January 1, 2003. Since then, EPA has learned that many suppliers of natural gas regularly sample the total sulfur content of the gas (in many cases, daily) and will 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 approached EPA, asking 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. Thus far, the Agency has addressed these requests on a case-by-case basis. Generally, in cases where the number of total sulfur samples far exceeds the requirements of Appendix D, EPA has allowed the sources to reduce the data to monthly averages. Then, if all of the monthly averages are below the 0.5 gr/100 scf , the fuel would be allowed to continue using the 0.0006 lb/mmBtu default SO_2 emission rate.

EPA believes that the current rule requirements for documenting the sulfur content of pipeline natural gas are too restrictive and need to be revised. For example, a source that takes only one or perhaps a handful of sulfur samples each year is allowed to use the 0.0006 lb/mmBtu default emission rate without question if all samples have ≤ 0.5 gr/100 scf of total sulfur. However, a source with hundreds of total sulfur sample results could possibly be disqualified from using the default emission rate if one sample exceeded the 0.5 gr/100 scf limit. To correct this inequitable situation, today's rule would revise Sections 2.3.1.4(a)(2) and (e) of Appendix D.

For the initial documentation that the gas meets the 0.5 gr/100 scf total sulfur limit, proposed Section 2.3.1.4(a)(2) would allow sources whose fuel suppliers have provided them with at least 100 daily (or more frequent) total sulfur samples from the previous 12 months to reduce the data to monthly averages. 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 have a total sulfur content of 0.5 gr/100 scf or less, the fuel would qualify as pipeline natural gas.

The 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 at least 100 total sulfur samples from the past 12 months are provided by the fuel supplier, 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 is also proposing to clarify the 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, revised Section 2.3.4.1 would require that a 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, whenever Section 2.3.7(c) of Appendix D requires the results of a monthly GCV sample to be applied ''starting from the date on which the sample was taken'', the owner or operator would apply the monthly average GCV value, starting from the latest date of any of the individual GCV samples used to calculate the monthly average. EPA believes that monthly averaging of the available GCV samples will ensure that representative robust GCV values are used in the Appendix D heat input calculations.

3. Requirement To Split Oil Samples

For affected units that combust fuel oil and use the Appendix D ''excepted'' 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 (if necessary) density of the oil. There are four basic oil sampling options described in Section 2.2: (a) Daily sampling; (b) flow proportional sampling (composite sample, up to 7 days); (c) sampling from a unit's storage tank after each addition of oil to the tank; and (d) sampling of each fuel lot (either upon receipt of the lot or sampling from supplier's storage tank prior to delivery). Regardless of which sampling option is selected, 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.

EPA believes that the requirement to split and maintain oil samples should only apply to samples that are taken at the affected facility. Today's rule would revise Section 2.2.5 of Appendix D to limit this requirement to samples that are taken on-site. Therefore, sources using the fourth sampling option in Section 2.2 of Appendix D, *i.e.*, sampling from each fuel lot, would no longer be required to split and maintain oil samples in the case where the samples are taken off-site, from the fuel supplier's storage container.

K. Appendix E

1. AETB Requirements

EPA proposes 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 an LME unit, would have to conform to ASTM D7036–04.

2. Reporting Data When the Correlation Curve Expires

For oil and gas-fired peaking units using the Appendix E ''excepted'' 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. Ordinarily, when data from a Part 75 monitoring system become invalid, missing data substitution procedures are applied. Section 2.5 of Appendix E contains missing data provisions that address the following situations: (a) When the monitored QA parameters are unavailable or invalid; (b) when the measured heat input rate is higher than the highest heat input rate on the correlation curve; (c) when NO_X emission controls are either not operating or not documented to be working properly; and (d) when emergency fuel is burned.

Conspicuously absent from Section 2.5 is a missing data procedure to follow when a correlation curve expires. To address this deficiency, today's rule would 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 when a baseline correlation curve expires. The MER would continue to be reported until a new correlation curve is generated.

L. Appendix F

1. NO_X Mass Calculations

EPA proposes to revise the manner in which NO_X mass data are collected under the XML–EDR format that will be required in 2009 as part of EPA's effort to re-engineer the Agency's data collection systems. Under the current reporting requirements, sources are required to report hourly NO_X mass emissions (lb) and then to sum these hourly records and divide by 2000 lb/ton to determine the quarterly NO_X mass emissions (tons). This is inconsistent with the manner in which SO_2 and CO_2 mass emissions data are reported and aggregated. For SO_2 and CO_2, the hourly values are reported as mass emission rates (lb/hr). The quarterly cumulative mass emissions are calculated by multiplying each reported hourly mass emission rate by the corresponding unit or stack operating time, summing these products, and then dividing the sum by 2000 lb/ton to get tons of SO_2 or CO_2.

Today's proposed rule seeks to harmonize the reporting formats by requiring the reporting of hourly NO_X mass emission rate (lb/hr) instead of hourly NO_X mass emission (lb), when the source transition from the current EDR reporting format to the XML–EDR reporting format. As previously discussed, sources may use either the existing EDR format or the new XML–EDR reporting format in 2008, but will be required to use the new XML-reporting format, only, in 2009.

Requiring the reporting of hourly NO_X mass emission rate (lb/hr) necessitates the modification of Equations F–24, and F–27 in Appendix F of Part 75 and the removal of Equation F–26. However, since the current EDR reporting format will continue to be supported through 2008, EPA must retain these equations in the rule until the transition to XML–EDR is complete. Therefore, EPA is proposing to revise Section 8 of Appendix F, by adding Equation F–24a for the reporting of hourly NO_X mass emission rate (lb/hr). Equation F–24a is a modified version of F–24, in which the operating time variable is removed. The use of Equation F–24a would be mandatory in the new XML–EDR format. Likewise, Equation F–27a would be added, which is a modified form of Equation F–27 that includes the operating time variable. In the XML–EDR format, cumulative NO_X mass emissions would be calculated using Equation F–27a.

Since both EDR reporting formats currently in use (*i.e.*, EDR versions 2.1 and 2.2) require reporting of hourly NO_X mass emissions (lb), the current versions of Equations F–24 and F–27 would remain in the rule. However, these equations would no longer be applicable in 2009, when the use of XML–EDR format is required for all affected sources.

Today's proposal also would revise Section 8.2 of Appendix F, by splitting it into two subsections, 8.2.1 and 8.2.2. Section 8.2 of the current rule describes 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. Section 8.2 cross-references other parts of the rule, rather than showing the actual equations used. Today's proposed rule would add Equation F–26a to proposed subsection 8.2.1 and Equation F–26b to proposed subsection 8.2.2, clearly showing how the NO_X mass emission rate is calculated on a wet and dry basis. Equation F–26 in Section 8.3 would be re-numbered as Equation F–26c. Proposed Equations F–26a and F–26b are currently used by sources to calculate NO_X mass emissions under Subpart H of Part 75. These equations are represented in the EDR reporting instructions, as Equations N–1 and N–2 respectively. EPA believes that it is appropriate to add these equations to the rule at this time.

2. Use of the Diluent Cap

Today's proposed rule would restrict the use of the diluent cap to NO_X emission rate calculations. The original purpose for implementing the diluent cap was to keep calculated NO_X emission rates from approaching infinity during periods of unit startup and shutdown, where the diluent gas (CO_2 or O_2) concentration is close to the level in the ambient air. However, the current rule allows 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 are also allowed to use the cap value for some of these calculations and not others. This 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, today's proposed rule would remove all of the references in Sections 4 and 5 of Appendix F which allow the diluent cap to be used for other parameters besides NO_X emission rate

3. Negative Emission Values

EPA proposes 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 proposes to require 0.0% CO_2 to be reported as the average CO_2 value for that hour. Third, EPA proposes 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.

4. Calculation of Stack Gas Moisture Content

Today's proposed rule would add Equation F–31 to a new Section 10 of Appendix F. This equation is used to calculate stack gas moisture values from wet and dry oxygen measurements, as described in Appendix A, Section 6.5.7(a). The equation is currently represented in the EDR reporting instructions as Equation M–1.

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

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 neither specifies how much fuel sampling data is required to develop a site-specific F-factor, nor how often the F-factor must be updated.

To address this issue, today's rule would 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.

6. Prorated F-Factors

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 requires 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 fails to specify 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.

Through the years, in response to inquiries about this, EPA has advised sources to use the best available auxiliary process data, such as fuel feed rates and measured GCV values, to provide heat input estimates for calculating the prorated F-factor, but no official Agency policy guidance has been issued. To correct this situation, today's rule would revise the definition of ''X_i'' (the fraction of the total heat input derived from each fuel) in the Equation F–8 nomenclature. The revised definition 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.

7. Default F-Factors

EPA proposes 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 are 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. These F-factors are needed because petroleum coke and tires are being used as a fuel by a number of units. EPA is also proposing 9,819 dscf/mmBtu for F_d and 1,840 scf CO_2/mmBtu for F_c as F-factors for sub-bituminous coal. These F-factors were calculated using Part 75, Appendix F, Equations F–7a and F–7b and representative composition and gross calorific value (GCV) data for each fuel.

8. Revisions to Equation F–23

Consistent with the proposed changes to § 75.11(e), expanding the applicability of Equation F–23 (which are discussed in detail in Section II.B.4 of this preamble), modifications would be made to Section 7 of Appendix F (introductory text), and to the Equation F–23 nomenclature.

M. Appendix G

Consistent with the changes to other parts of the rule, EPA proposes 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.

N. Appendix K

Today's proposed rule 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, the current rule requires the use of paired sorbent traps 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 of Appendix K specify consequences of varying severity. As discussed in the following paragraphs, EPA has reconsidered these rule provisions and has concluded that some of the consequences are too lenient while others are unnecessarily harsh. The Agency is therefore proposing to revise them to make them more consistent and equitable.

Section 75.15(h) currently provides a measure of relief to the affected sources whenever one of the paired traps is accidentally lost, damaged, or broken and cannot be analyzed. In such cases, the owner or operator is allowed 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 the rule does not require any adjustment of the data to compensate for the loss of one of the samples. In view of this, EPA is proposing 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 is also proposing 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 current rule does not say what to do if this criterion is not met. Rather, Table K–1 indicates that the appropriate consequences are to be determined on a ''case-by-case'' basis. EPA has reconsidered this approach and is proposing to revise it, because it opens the door to inconsistent application of the sorbent trap monitoring methodology. Therefore, Table K–1 would be revised 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 single trap adjustment factor of 1.222 is applied to the measured Hg concentration.

Appendix K currently requires that the data from a sorbent trap monitoring system be invalidated whenever the relative deviation between the Hg concentrations measured by the paired traps is greater than 10 percent. EPA proposes 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. EPA is also proposing, for consistency with the proposed changes § 75.22(a) (which are discussed in Section II.C.3 of this preamble), to revise Table K–1 to include an alternative relative deviation specification of 20 percent for paired sorbent traps, where low effluent concentrations of Hg ($\leq 1\ \mu g/m^3$) are encountered.

Today's proposed rule would add two new paragraphs, (k) and (l), to § 75.15. Proposed § 75.15(k) would require 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 require a diagnostic RATA of the sorbent trap system whenever the size of the sorbent traps or the type of sorbent material is changed. Data from the modified sorbent trap system would not be 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. EPA is proposing to add these requirements because the relative accuracy and bias of a sorbent trap monitoring system are dependent upon both the trap design and the type of sorbent material used.

Finally, today's proposed rule would revise section 7.2.3 of Appendix K to require that the sample flow rate through a sorbent trap monitoring system must be zero when the unit is not operating. This clarification is needed to prevent the system from sampling ambient air during periods when the combustion unit is off-line. Sampling ambient air when the unit is not in operation would artificially lower the Hg concentrations measured by the sorbent traps, resulting in under-reporting of Hg mass emissions.

II. Administrative Requirements

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 proposed 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 2203.01. The information requirements are based on the proposed 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 existing Part 75 rule requirements are covered by existing ICRs for the Acid Rain Program (EPA ICR number 1633.13; OMB control number 2060–0258), the NO_X SIP Call (EPA ICR number 1857.03; OMB number 2060–0445), and the Clean Air Interstate Rule (EPA ICR number 2152.01). The separate ICR for the proposed 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 proposed 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.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this rule, which includes this ICR, under Docket ID number OAR–2005–0132. Submit any comments related to the ICR for this proposed rule to EPA and OMB.

See **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after August 22, 2006, a comment to OMB is best assured of having its full effect if OMB receives it by September 21, 2006. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

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 proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; or (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 proposed 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. The proposed rule revisions represent minor changes to existing monitoring requirements used in EPA emission trading programs. 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 proposed revisions is 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.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under 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 proposed 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 in the private sector in any one year. Thus, today's proposed 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 would 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 would clarify certain issues that have been raised during ongoing implementation of the existing rule and would 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 proposed modifications to Part 75, but the rule revisions and the impact on the States would not be 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 proposed rule does not have federalism implications. This proposed rule 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 proposed rule revisions represent minor adjustments to existing regulations. The revisions primarily would 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 would clarify certain issues that have been raised during ongoing implementation of the existing rule and would 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 proposed modifications to Part 75, but the rule revisions and the impact on the States would not be significant. Thus, Executive Order 13132 does not apply to this proposed rule. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

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 proposed rule does not have tribal implications, as specified in Executive Order 13175. The proposed action makes minor revisions to existing rule requirements. Thus, Executive Order 13175 does not apply to this proposed rule. The EPA specifically solicits additional comment on the proposed rule from tribal officials.

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 ''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.

This proposed rule is not subject to the Executive Order because it is not economically significant as defined in Executive Order 12866, and because the Agency does not have reason to believe the proposed revisions to certain monitoring and reporting requirements implicate any environmental health or safety risks, including any specific risks that present a disproportionate risk to children. The public is invited to submit or identify peer-reviewed studies and data, of which the agency may not be aware, that are relevant to the environmental health or safety risks to children that could be implicated by this proposed action.

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

This proposed rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 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 proposed rule includes updated information on a number of voluntary consensus standards previously included in 40 CFR Part 75, as well as the proposed addition of certain other voluntary consensus standards. The EPA welcomes comments on this aspect of the proposed rulemaking and specifically invites the public to identify other potentially applicable voluntary consensus standards and to explain why such standards should be used in this regulation.

List of Subjects in 40 CFR Parts 72 and 75

Environmental protection, Acid rain, Administrative practice and procedure, Air pollution control, Carbon dioxide, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: August 4, 2006.

Stephen L. Johnson,

Administrator.

For the reasons set forth in the preamble, EPA proposes to amend chapter I of title 40 of the Code of Federal Regulations 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. In the definition of ''Capacity factor'', by adding the words ''(or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity)'' after the word ''capacity'' in paragraph (1), by removing the word ''design'' and adding in its place the words ''rated hourly'' in paragraph (2), and by adding the word ''rate'' after the new phrase ''rated hourly heat input'' in paragraph (2);

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'', ''Qualified Individual'', and ''Specialty gas producer''; and

f. Removing the definitions for ''Calibration gas'', ''Gas manufacturer's intermediate standard (GMIS)'', ''NIST/EPA-approved certified reference material or NIST/EPA-approved CRM'', ''NIST traceable reference material (NTRM)'', ''Research gas material (RGM)'', ''Research gas mixture (RGM)'', ''Standard reference material or SRM'', ''Standard reference material-equivalent compressed gas primary reference material (SRM-equivalent PRM)'', and ''Zero air material''.

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.

* * * * *

EPA protocol gas * * * 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 shut down 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).

* * * * *

Qualified Individual means an individual who meets the requirements as described in ASTM D7036–04.

* * * * *

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, 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, (d), 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 shutdown 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'' and adding in its place ''D240–00'', in paragraph (a)(2);

c. Removing ''D287–82 (Reapproved 1987)'' and adding in its place ''D287–92 (2000)e1'', in paragraph (a)(3);

d. Removing ''D388–92'' and adding in its place ''D388–99e1'', in paragraph (a)(4);

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

f. Adding the phrase ''(1999)'' at the end of ''D1072–90'', in paragraph (a)(6);

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

h. Adding the phrase ''(1997)e1'' at the end of D1250–80, and by removing the phrase ''(Reapproved 1990)'', in paragraph (a)(8);

i. Removing the phrase ''D1298–85 (Reapproved 1990)'' and adding in its place ''D1298–99'', in paragraph (a)(9);

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

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

l. Removing ''D1552–90'' and adding in its place ''D1552–01'', in paragraph (a)(12);

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

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

o. Adding the phrase ''(2000)'' 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'', in paragraph (a)(17);

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

s. Removing ''D2234–89'' and adding in its place ''D2234–00e1'', in paragraph (a)(19);

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

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

v. Removing ''D2503–82 (Reapproved 1987)'' and adding in its place ''D2503–92 (1997)'', in paragraph (a)(22);

w. Removing ''D2622–92'' and adding in its place ''D2622–98'', in paragraph (a)(23);

x. Removing ''D3174–89'' and adding in its place ''D3174–00'', in paragraph (a)(24);

y. Adding the phrase ''(1997)e1'' after ''D3176–89'', in paragraph (a)(25);

z. Adding the phrase ''(1997)'' after ''D3177–89'', in paragraph (a)(26);

aa. Adding the phrase ''(1997)'' after ''D3178–89'', in paragraph (a)(27);

bb. Removing ''D3238–90'' and adding in its place ''D3238–95 (2000)e1'', in paragraph (a)(28);

cc. Removing ''D3246–81 (Reapproved 1987)'' and adding in its place ''D3246–96'', in paragraph (a)(29);

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

ee. Removing ''D3588–91'' and adding in its place ''D3588–98'', in paragraph (a)(31);

ff. Removing ''D4052–91'' and adding in its place ''D4052–96 (2002)e1'', in paragraph (a)(32);

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

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

ii. Removing ''D4239–85'' and adding in its place ''D4239–02'', in paragraph (a)(35);

jj. Removing ''D4294–90'' and adding in its place ''D4294–98'', in paragraph (a)(36);

kk. Removing the phrase ''(Reapproved 1989)'' and adding in its place the phrase ''(2000)'', in paragraph (a)(37);

ll. Adding the phrase ''(2001)'' after ''D4891–89'', in paragraph (a)(39);

mm. Removing ''D5291–92'' and adding in its place ''D5291–01'', in paragraph (a)(40);

nn. Adding the phrase ''(1997)'' after ''D5373–93'', in paragraph (a)(41);

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

pp. Adding new paragraphs (a)(45), (a)(46), (a)(47), and (a)(48);

qq. Removing the phrase ''with September 1990 Errata'' and adding in its place the phrase ''(Reaffirmed 1995)'', in paragraph (b)(1);

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

ss. Adding the phrase ''(Reaffirmed 2001)'' after ''ASME–MFC–5M–1985'', in paragraph (b)(3);

tt. Removing the phrase ''1987 with June 1987 Errata'' and adding in its placethe number ''1998'' at the end of ''MFC–6M-'', in paragraph (b)(4);

uu. Removing the date ''1992'' and adding in its place the date ''2001'' in the parenthetical, in paragraph (b)(5);

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 ''1996'' at the end of ''GPA Standard 2172-'', in paragraph (d)(1);

xx. Removing the number ''90'' and adding in its place the number ''1999'' at the end of ''GPA Standard 2261-'', in paragraph (d)(2);

yy. Adding the phrase ''(1st edition)'' after the date ''December 1994'', removing the phrase ''April 1992 (reaffirmed January 1997)'' and adding in its place the phrase ''June 2001'', adding the phrase ''(Reaffirmed September 2000)'' after the date ''September 1995'', adding the phrase ''(1st Edition)'' after the date ''June 1996'', adding the phrase ''(1st Edition)'' after the date ''April 1995'', and adding the phrase ''(1st Edition)'' after the date ''March 1997'', in paragraph (f)(1);

zz. Adding the phrase ''Manual of Measurement Standards, Chapter 4:'' after the phrase ''(API)'', adding the phrase ''(Provers Accumulating at Least 10,000 Pulses), Measurement Coordination (Second Edition, March 2001)'', after the words ''Conventional Pipe Provers'', adding the phrase ''(First Edition)'' after the words ''Small Volume Provers'', adding the phrase ''Measurement Coordination (Second Edition, May 2000)'' after the phrase ''Master-Meter Provers,'' and removing the phrase ''from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993)'', in paragraph (f)(3); and

aaa. 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 Liquified 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 D5865–01ae1, ''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.

* * * * *

(f) * * *

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22—Testing Procedures: 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 paragraph (e) introductory text, (e)(1) and (e)(3) introductory text;

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

f. 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 75.15 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 paragraphs (k) and (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 1.222.

* * * * *

(k) When a sorbent trap monitoring system is tested for relative accuracy, both the size of the sorbent traps and the type of sorbent material used by the traps shall be the same as for daily operation of the system.

(l) Whenever the size of the sorbent traps or the type of sorbent material used by the traps is changed, the owner or operator shall conduct a diagnostic RATA of the sorbent trap monitoring system. The modified system shall not be used to report Hg emissions under this part until the RATA has been performed and passed. Notwithstanding this requirement, Hg concentrations measured by the modified system during a successful RATA may be reported as quality-assured data under this part.

10. 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. Replacing both occurrences of the phrase ''steam flow'' with 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.

* * * * *

11. 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 emissions are controlled, 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)'' in and by

using the NO_X MEC instead of the NO_X MPC.

12. Section 75.19 is amended by:

a. Revising paragraph (a)(1);

b. Revising paragraph (c)(1)(i);

c. 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);

d. Adding the word ''add-on'' before the first instance of the phrase ''NO_X controls'', in paragraph (c)(1)(iv)(H)(*3*);

e. Adding the phrase ''(1st Edition)'' after the date ''December 1994'', replacing the phrase ''April 1992 (reaffirmed January 1997)'' with the date ''June 2001'' after the phrase ''Stationary Tanks by Automatic Tank Gauging,'', adding the phrase ''(Reaffirmed September 2000)'' after the date ''September 1995'', adding the phrase ''(1st Edition)'' after the date ''June 1996'', adding the phrase ''(1st Edition)'' after the date ''April 1995'', and adding the phrase ''(1st Edition)'' after the date ''March 1997'', in paragraph (c)(3)(ii)(B)(*2*);

f. Removing the words ''from Table LM–1 of this section'' from the first sentence of paragraph (c)(4)(i)(A);

g. Revising the heading to paragraph (c)(4)(ii); and

h. 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. 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 SO_2 emission rate for each such fuel.

* * * * *

(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.

* * * * *

13. 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

* * * * *

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

15. Section 75.22 is amended by revising paragraphs (a)(5) and (a)(7) to read as follows:

§ 75.22 Reference test methods.

(a) * * *

(5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E, as applicable, are the reference methods for determining SO_2 and NO_X pollutant concentrations. Alternatively, Method 20 may be used as the reference method for relative accuracy test audits of NO_X CEMS installed on combustion turbines. (Methods 6A and 6B may also be used to determine SO_2 emission rate in lb/mmBtu.) Methods 7, 7A, 7C, 7D, or 7E 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 exceptions or options of method 7E:

(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) 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;

(iii) 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.

* * * * *

(7) ASTM D6784–02, ''Standard Test Method for Elemental, Oxidized, Particle-Bound, and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources'' (also known as the Ontario Hydro Method)(incorporated by reference, *see* § 75.6) is the reference method for determining Hg concentration. 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 shall be followed instead of the procedures in sections 7.5.33 and 11.1.3 of Method 29, and the QA/QC

procedures in section 13.4.2 of ASTM D6784–02 shall be performed instead of the procedures in section 9.2.3 of Method 29. The tester may also opt to use the sample recovery and preparation procedures in ASTM D6784–02 instead of the Method 29 procedures, as follows: sections 8.2.8 and 8.2.9.1 of Method 29 may be replaced with sections 13.2.9.1 through 13.2.9.3 of ASTM D6784–02 ; sections 8.2.9.2 and 8.2.9.3 of Method 29 may be replaced with sections 13.2.10.1 through 13.2.10.4 of ASTM D6784–02; section 8.3.4 of Method 29 may be replaced with section 13.3.4 or 13.3.6 of ASTM D6784–02 (as appropriate); and section 8.3.5 of Method 29 may be replaced with section 13.3.5 or 13.3.6 of ASTM D6784–02 (as appropriate). Whenever ASTM D6784–02 or Method 29 is used, paired sampling trains are required. To validate a RATA 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. If the RD criterion is met, use the average Hg concentration measured by the two trains (vapor phase, only) in the relative accuracy calculations. As a second alternative, an instrumental reference method or other suitable reference method capable of measuring total vapor phase Hg may be used, subject to the approval of the Administrator.

* * * * *

16. Section 75.32 is amended by replacing the phrase ''need not be calculated during the'' with the phrase ''shall be calculated for each hour during each'', by replacing the word ''last'' with the word ''each'', and by removing the phrase ''as the monitor availability used'' after the words ''data period'', in paragraph (b).

17. Section 75.33 is amended by:

a. Replacing the word ''Whenever'' with the word ''If'', and by replacing the words ''each hour of each'' with the words ''that hour of the'', in paragraph (b)(1) introductory text;

b. Replacing the word ''Whenever'' with the word ''If'', and by replacing the words ''each hour of each'' with the words ''that hour of the'', in paragraph (b)(2) introductory text;

c. Replacing the word ''Whenever'' with the word ''If'', and by replacing the word ''each'' with the words ''that hour of the'', in paragraphs (b)(3) and (b)(4);

d. Replacing the word ''Whenever'' with the word ''If'', and by replacing the words ''each hour of each'' with the words ''that hour of the'', in paragraphs (c)(1) introductory text, (c)(2) introductory text, (c)(3), and (c)(4);

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

f. Revising Table 3 in paragraph (e)(3); and

h. Replacing the word ''Whenever'' with the word ''If'', and by replacing the words ''each hour of each'' with the words ''that hour of the'', in paragraphs (d)(1), (d)(2), (d)(3), and (d)(4).

The revisions and additions read as follows:

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

* * * * *

(c) * * *

(8) * * *

(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, as provided in § 75.34, the unit may, upon approval, use the maximum controlled emission rate 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, 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 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 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	$N \le 24$	Average	2160 hours *	Yes
	$N > 24$	The greater of:		
		Average	HB/HA	No
		90th percentile	2160 hours *	Yes
90 or more, but below 95	$N \le 8$	Average	2160 hours *	Yes
	$N > 8$	The greater of:		
		Average	HB/HA	No
		95th percentile	2160 hours *	Yes
80 or more, but below 90	$N > 0$	Maximum value [1]	2160 hours *	Yes
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, as provided in § 75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 2160 quality-assured monitor operating hours. Alternatively, 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 databases 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, 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 2160 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	$N \le 24$	Average	2160 hours *
	$N > 24$	90th percentile	2160 hours *
90 or more, but below 95	$N \le 8$	Average	2160 hours *
	$N > 8$	95th percentile	2160 hours *
80 or more, but below 90	$N > 0$	Maximum value	2160 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 2160 quality-assured monitor operating hours.

* * * * *

18. Section 75.34 is amended by:

a. Revising paragraph (a) introductory text;

b. Amending paragraph (a)(2)(ii) by replacing the words ''and (c)(3)'' with '', (c)(3) and (c)(5), and § 75.38(c),'';

c. Revising paragraph (a)(3);

d. Adding paragraph (a)(5); and

e. Revising paragraph (d) by replacing the words ''paragraphs (a)(1) and (a)(3)'' with ''paragraphs (a)(1), (a)(3) and (a)(5)''.

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 SO_2 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 hourly controlled 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.

* * * * *

19. 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.

20. 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 redundant backup sorbent trap monitoring system (or vice-versa), when both monitoring systems are out-of-service and quality-assured Hg concentration data from a 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 reference method, or an approved alternative monitoring system.

21. Section 75.53 is amended by:

a. Revising paragraph (a)(1);

b. Replacing the phrase ''(d) or (f)'' with 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 remain in effect 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.

22. 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); and

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

The revisions and additions 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).

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

Code	Hourly emissions/flow measurement or estimation method
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 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.)
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 1.222 when one of the paired traps is invalidated or damaged (*See* Appendix K § 8).
33	Hourly Hg concentration determined from the trap resulting in the higher Hg concentration when the relative deviation between the paired traps is greater than 10 percent (*See* Appendix K § 8).
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.

* * * * *

23. 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. Replacing the period with 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. Replacing the period with 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. Replacing the period with a semicolon and adding the word "and" to the end of the paragraph, in paragraph (d)(1)(x);

i. Adding paragraph (d)(1)(xi);

j. Replacing the period with a semicolon and adding the word "and" to the end of the paragraph, in paragraph (d)(2)(x);

k. Adding paragraph (d)(2)(xi);

l. Revising paragraph (f)(1)(iii);

m. Removing the word "and" at the end of paragraph (f)(1)(xi);

n. Replacing the period with a semicolon at the end of paragraph (f)(1)(xii);

o. Adding paragraphs (f)(1)(xiii) and (f)(1)(xiv); and

p. Replacing the word "Component" with 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.

* * * * *

24. 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. Replacing the phrase "For the qualifying test for off-line calibration, the owner or operator shall indicate" with 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. Replacing the period with 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. Replacing the period with 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. Replace the phrase ''Cycle time result for the entire system'' with the phrase ''Total cycle time'', in paragraph (a)(6)(ix);

q. Adding paragraphs (a)(7)(ix) and (a)(7)(x);

r. Revising paragraph (a)(8);

s. Removing and reserving paragraph (a)(12)(iii);

t. Removing the number ''(2)'' from the paragraph identifier ''§ 75.64(a)(2)'' in the second sentence of paragraph (a)(13);

u. 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);

v. 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);

w. Removing the word ''and'' after the semicolon at the end of paragraph (b)(4)(i)(H);

x. Replacing the period with a semicolon and adding the word ''and'' at the end of paragraph (b)(4)(i)(I);

y. Adding paragraph (b)(4)(i)(J);

z. Revising paragraphs (b)(4)(ii)(A), (b)(4)(ii)(B), and (b)(4)(ii)(F);

aa. Removing the word ''and'' after the semicolon at the end of paragraph (b)(4)(ii)(L);

bb. Replacing the period with a semicolon and adding the word ''and'' at the end of paragraph (b)(4)(ii)(M);

cc. Adding paragraph (b)(4)(ii)(N);

dd. 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);

ee. Adding the phrase ''This requirement remains in effect through December 31, 2008'' after the word ''run'', in paragraph (b)(5)(i)(H);

ff. Adding the phrase ''(as applicable). This requirement remains in effect through December 31, 2008'' after the word ''level'', in paragraph (b)(5)(iv)(A);

gg. Removing the word ''and'' after the semicolon at the end of paragraph (b)(5)(iv)(G);

hh. Replacing the period with a semicolon and adding the word ''and'' at the end of paragraph (b)(5)(iv)(H);

ii. Adding paragraph (b)(5)(iv)(I);

jj. Removing the word ''and'' after the semicolon at the end of paragraph (d)(1)(xi);

kk. Replacing the period with a semicolon and adding the word ''and'' at the end of paragraph (d)(1)(xii);

ll. Adding paragraph (d)(1)(xiii);

mm. Removing the phrase '', multiplied by 1.15, if appropriate'' from paragraph (d)(2)(iii);

nn. Removing the word ''and'' after the semicolon at the end of paragraph (d)(2)(iv);

oo. Replacing the period with a semicolon at the end of paragraph (d)(2)(v); and

pp. 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) * * *

(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, 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 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).)

* * * * *

25. 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.

* * * * *

26. 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) *Initial certification and recertification test notifications.* 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 shutdown 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) *Periodic relative accuracy test audits, appendix E retests, and low mass emissions unit retests.* 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.

(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.

* * * * *

27. Section 75.62 is amended by:

a. Revising paragraph (a)(1); and

b. Replacing the number ''45'' with the number ''21'' before the phrase ''days prior'', in paragraph (a)(2).

The revisions and additions 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.

* * * * *

28. 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) by adding the words ''certifying the accuracy of the submission'' after the word ''signature''.

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.

* * * * *

29. Section 75.64 is amended by:

a. Revising paragraph (a) introductory text;

b. Revising paragraph (a)(2)(xiv);

c. Removing paragraph (a)(8);

d. Redesignating paragraphs (a)(3) through (a)(7) as paragraphs (a)(8) through (a)(12), and redesignating paragraphs (a)(9) through (a)(11) as paragraphs (a)(13) through (a)(15);

e. Adding new paragraphs (a)(3) through (a)(7); and

f. Replacing the citation ''§ 75.59'', with ''§ 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). 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), 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 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 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 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;

(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), 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 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 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 is used and a wall effects adjustment factor is applied.

* * * * *

§ 75.66 [Amended]

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

31. Section 75.71 is amended by:

a. In paragraph (a)(1), by replacing the second occurrence of the phrase ''CO_2 diluent gas monitor'' with the phrase ''CO_2 diluent gas monitoring system'';

b. Replacing the phrase ''O_2 or CO_2 diluent gas monitor'' with the phrase ''O_2 or CO_2 monitoring system'', in paragraph (a)(2); and

c. 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.

* * * * *

32. Section 75.72 is amended by:

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

b. 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.

* * * * *

(f) [Reserved]

* * * * *

33. Section 75.73 is amended by:

a. Revising paragraph (c)(3);

b. Replacing the number ''45'' with the number ''21'' in paragraphs (e)(1) and (e)(2);

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

d. Replacing the phrase ''paragraph (a)'' with 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), 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) 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), 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 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 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 is used and a wall effects adjustment factor is applied.

* * * * *

34. Section 75.74 is amended by:

a. Replacing the phrase ''In the time period 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'', with 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. Replacing all occurrences of the words ''§ 75.31, § 75.33, or § 75.37'' with 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. Replacing the words ''October 1 of the previous calendar year'' with ''January 1'' in paragraph (c)(6)(v); and
n. Revising paragraph (c)(11).
The revisions and additions 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 results of all daily calibration error tests and flow monitor interference checks performed in the time period from April 1 through April 30 shall be reported. The owner or operator shall also report unit operating data recorded in the time period from April 1 through April 30 beginning with the day of the first required daily calibration error test or flow monitor interference check performed whenever the XML reporting format is used. The owner or operator may also report the hourly emission data in the time period from April 1 through April 30. However, only the emission data recorded in the time period from May 1 through September 30 shall be used for NO_X mass compliance determination;

* * * * *

(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''.
35. Section 75.81 is amended by:
a. Revising paragraph (a)(4);
b. Revising paragraph (c)(1);
c. Revising paragraph (c)(2);
c. Removing Eq. 1 from paragraph (d)(1);
d. Revising paragraph (d)(2);
e. Adding paragraph (d)(4)(iv); and
f. 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. 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 must be from the same source of supply as the coal combusted at the start of the Hg mass emissions reduction program. The minimum time per run shall be 1 hour if an instrumental reference method is used. If Method 29 or the Ontario Hydro method is used, paired sampling trains are required for each test run and the run must be long enough to ensure that sufficient Hg is collected to analyze. When Method 29 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 or Ontario Hydro method test run, the paired trains must meet the percent relative deviation (RD) requirement in § 75.22(a)(7). If the RD specification is met, the results of the two trains shall be averaged arithmetically. 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).

(2) 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:

$$E = 8760\ K\ C_{Hg} Q_{max} \qquad (\text{Eq. } 1)$$

Where:

E = Estimated annual Hg mass emissions from the affected unit, (ounces/year)

K = Units conversion constant, 9.978 × 10^{-10} oz-scm/[mu]g-scf

8760 = Number of hours in a year

CH_g = The highest Hg concentration (μg/scm) from any of the test runs or 0.50 μg/scm, whichever is greater

Qmax = Maximum potential flow rate, determined according to section 2.1.4.1 of appendix A to this part, (scfh)

Equation 1 of this section assumes that the unit operates year-round at its maximum potential flow rate. 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 fuel supply. 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 fuel supply. 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 each individual unit is tested to demonstrate that its potential to emit does not exceed 464 ounces of Hg per year, in accordance with paragraphs (c) and (d) of this section. If the units sharing the common stack 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 the 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. 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 for any of the tested units serving the common stack or 0.50 μg/scm, whichever is greater. Notwithstanding these requirements, the emission testing required under paragraphs (c) and/or (d)(3) of this section may be performed at the common stack in the following circumstances:

(i) The initial certification testing required under paragraph (c) of this section may be performed at the common stack if all of the units using the stack are affected units and if, prior to entering the common stack, the effluent gas streams from the individual units are combined together upstream of an emission control device that reduces the Hg concentration. If this testing option is chosen:

(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;

(C) When calculating E, the estimated maximum potential annual Hg mass emissions from the stack, 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) shall be substituted into Equation 1;

(D) 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

(E) 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) For all common stack configurations, the retests required under paragraph (d)(3) of this section may 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. The due date for the next retest shall be determined as follows:

(A) To calculate E, 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) shall be substituted 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.

* * * * *

36. Section 75.82 is amended by adding paragraphs (b)(3), (c)(4), and (d)(3) to 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.

37. 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)'', respectively, 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. Replacing the phrase ''paragraph (a)'' with the phrase ''paragraphs (a) and (b)'' in paragraph (f)(1)(ii) introductory text;

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), 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 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 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 is used and a wall effects adjustment factor is applied.

* * * * *

38. 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; and

d. Adding a new fourth sentence after the third sentence of section 2.1.3.

e. Revising paragraph (3) of section 3.2;

f. Replacing the phrase ''continuous emission monitoring system(s)'' with the phrase ''monitoring component of a continuous emission monitoring system that is'' in section 3.5;

g. Revising section 5.1;

h. Redesignating section 6.1 as section 6.1.1;

i. Adding new sections 6.1 and 6.1.2;

j. Revising the second and third sentences and adding a new fourth sentence to section 6.2, introductory text;

k. Replacing the words ''section 2.6'' with the words ''section 2.2.1'', in paragraph (g) of section 6.2;

l. Adding paragraph (h) to section 6.2;

m. Adding a new fourth sentence to section 6.3.1, introductory text;

n. Revising the introductory text of section 6.4;

o. 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;

p. 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;

q. 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;

r. Adding the words ''and LME units'' after the words ''For peaking units'' in the third sentence of paragraph (d)(1) of section 6.5.2.1;

s. Replacing the words ''quarterly report'' in the first sentence with the words ''monitoring plan'', by adding the words ''or mmBtu/hr'' after the term ''lb/hr'', by replacing the number ''75.64'' with the number ''75.53'', by adding the words ''and LME units'' after the words ''Except for peaking units'', and by revising the words ''electronic quarterly report (as part of the electronic monitoring plan)'' to read ''electronic monitoring plan'' in paragraph (e) of section 6.5.2.1;

t. Replacing all occurrences of the words ''section 3.2'' with 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;

u. Adding the words ''and the same type of sorbent material'' after the words ''same-size trap'' in the third-to-last sentence of section 6.5.7, paragraph (a);

v. Revising section 6.5.10;

w. Adding a sentence at the end of section 7.6.1;

x. Revising the words ''scfh/megawatts or scfh/1000 lb/hr of steam'' to read ''scfh/megawatts, scfh/1000 lb/hr of steam, or scfh/(mmBtu/hr of steam output)'' at the end of the R_{ref} variable definition, and by revising the words ''megawatts or 1000 lb/hr of steam,'' to read ''megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output'' at the end of the L_{avg} variable definition in paragraph (a) of section 7.7; and

y. Revising the words ''Btu/kwh or Btu/lb steam load'' to read ''Btu/kwh, Btu/lb steam load, or mmBtu heat input/mmBtu steam output'' in the $(GHR)_{ref}$ variable definition, and by revising the words ''megawatts or 1000 lb/hr of steam'' to read ''megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output'' at the end of the L_{avg} variable definition, in paragraph (c) of section 7.7.

The revisions and additions read as follows:

Appendix A to Part 75—Specifications and Test Procedures

* * * * *

2. Equipment Specifications

2.1.1.1 Maximum Potential Concentration

* * * * *

(c) When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D3177–89 (1997), ''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 Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy''; 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 X-Ray Spectrometry'' for sulfur content of solid or liquid fuels; ASTM D3176–89 (1997)e1, ''Standard Practice for Ultimate Analysis of Coal and Coke''; ASTM D240–00 (Reapproved 1991), ''Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter''; or ASTM D5865–01ae1, ''Standard Test Method for Gross Calorific Value of Coal and Coke'' (incorporated by reference under § 75.6).

* * * * *

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 5.0 percent of the span 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 span 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 0.6 $\mu g/m^3$. 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.

For the purpose of part 75, calibration gases include the following:

5.1.1 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) 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 may not certify a calibration gas as an EPA Protocol Gas unless it participates in the PGVP, 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*.

5.1.2 Mercury Standards

For 7-day calibration error tests of Hg concentration monitors and for daily calibration error tests of Hg monitors, either elemental Hg standards or a NIST-traceable source of oxidized Hg may be used. For linearity checks, 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.

5.1.3 Zero Air Material

(a) A calibration gas certified by the specialty gas producer or vendor not to contain concentrations of SO_2, NO_X, or total hydrocarbons above 0.1 parts per million (ppm), a concentration of CO above 1 ppm, or a concentration of CO_2 above 400 ppm;

(b) Ambient air conditioned and purified by a CEMS for which the CEMS manufacturer or vendor certifies that the particular CEMS model produces conditioned gas that does not contain concentrations of SO_2, NO_X, or total hydrocarbons above 0.1 ppm, a concentration of CO above 1 ppm, or a concentration of CO_2 above 400 ppm;

(c) For dilution-type CEMS, conditioned and purified ambient air provided by a conditioning system concurrently supplying dilution air to the CEMS; or

(d) A multi-component mixture certified by the supplier of the mixture that the concentration of the component being zeroed is less than or equal to the applicable concentration specified in paragraph (a) of this section, and that the mixture's other components do not interfere with the CEM readings.

* * * * *

6.1 General Requirements

* * * * *

6.1.2 Requirements for Air Emission Testing Bodies

(a) 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. 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. 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. 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, both for initial certification 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, and if the Hg monitor measures on a dry basis, 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 and the monitoring system measures Hg concentration on a dry basis, 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 (*see also* Figure 6 at the end of this appendix). Use a zero-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. To determine the upscale elapsed time, 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 stable starting gas value and start time, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of flue gas emissions until the response stabilizes. Record the stable ending stack emissions value and the end time of the test using the DAHS. Determine the upscale elapsed time as the time it takes for 95.0 percent of the step change to be achieved between the stable starting gas value and the stable ending stack emissions value. Then repeat the procedure, starting by injecting the high-level gas concentration to determine the downscale elapsed time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable starting gas value and the stable ending stack emissions value. End the downscale test by measuring the stable concentration of flue gas emissions. Record the stable starting and ending monitor values, the start and end times, and the downscale elapsed time for the monitor using the DAHS. 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 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. Report the slower of the two elapsed times (upscale or downscale) as the cycle time for the analyzer. (*See* Figure 5 at the end of this appendix.) 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 from on the range giving the longer cycle time. 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:

* * * * *

6.5.10 Reference Methods

The following methods from appendix A to part 60 of this chapter or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 or its allowable alternatives in appendix A to part 60 of this chapter (except for Methods 2B and 2E) for stack gas velocity and volumetric flow rate; Methods 3, 3A or 3B for O_2 and CO_2; Method 4 for moisture; Methods 6, 6A or 6C for SO_2; Methods 7, 7A, 7C, 7D or 7E for NO_X, excluding the exceptions of Method 7E identified in § 75.22(a)(5); and either the Ontario Hydro Method, Method 29 in appendix A–8 to part 60 of this chapter, or an approved instrumental method for Hg (see § 75.22).

* * * * *

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 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''.

* * * * *

39. 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 words ''scfh/megawatts or scfh/1000 lb/hr of steam load'' to read ''scfh/megawatts, scfh/1000 lb/hr of steam load, or scfh/(mmBtu/hr thermal output)'' at the end of the R_h variable definition, and by revising the words ''megawatts or 1000 lb/hr of steam'' to read ''megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output'' in the L_h variable definition, in paragraph (a) of section 2.2.5;

h. Revising the words Btu/kwh or Btu/lb steam load'' to read ''Btu/kwh, Btu/lb steam load, mmBtu heat input/mmBtu thermal output'' in the $(GHR)_h$ variable definition, and by revising the words ''megawatts or 1000 lb/hr of steam'' to read ''megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output'' in the L_h variable definition, in paragraph (a)(2) of section 2.2.5;

i. Replacing the word ''five'' with the word ''twenty'', and by replacing the word ''years'' with the word ''quarters'', in paragraph (c)(4) of section 2.3.1.3;

j. Revising paragraph (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; and

n. Replacing the term ''dscm'' with ''scm'' in 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 periodic Hg emission tests described in §§ 75.81(c)(1) and 75.81(d)(4)(iii).

* * * * *

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, off-line calibration error tests may be used to validate data from the monitor for up to 26 consecutive unit or stack operating hours, after which data from the monitor become invalid until an on-line calibration error test of the monitor is passed. Once the required on-line calibration error test has been passed, another 26 operating hour cycle of data validation using off-line calibration error tests may begin. Each off-line calibration error test that is used for data validation has a prospective data validation window of 26 clock hours, as described in section 2.1.5 of this appendix. If the sequence of consecutive operating hours validated by off-line calibrations is broken before reaching the 26th consecutive unit or stack operating hour, data from the monitor become invalid and an on-line calibration error test must be passed to re-establish the quality-assured data status. The sequence is considered broken when a unit or stack operating hour is not contained within the 26 clock hour data validation window of a passed off-line calibration error test.

(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 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.

* * * * *

2.3.2 * * *

(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 O_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 be 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.

* * * * *

40. 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 words ''Btu/kwh or Btu/lb steam load'' to read ''Btu/kwh, Btu/lb steam load, or mmBtu heat input/mmBtu thermal output'' in the $(GHR)_{base}$ variable definition, and by revising the words ''megawatts or 1000 lb/hr of steam'' to read ''megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output'' in the L_{avg} variable definition, in paragraph (c) of section 2.1.7.1;

e. Removing the word ''or'' and adding the phrase'',100 scfh/(mmBtu/hr of steam load), or (lb/hr)/(mmBtu/hr thermal output)'' at the end of the R_h variable definition, and by replacing the phrase ''megawatts or 1000 lb/hr of steam'' with the phrase ''megawatts, 1000 lb/hr of steam, or mmBtu /hr thermal output'' in the L_h variable definition, in paragraph (a) of section 2.1.7.2;

f. Replacing the phrase the ''Btu/kwh or Btu/lb steam load'' with the phrase ''Btu/kwh, Btu/lb steam load, or mmBtu heat input/mmBtu thermal output'' in the $(GHR)_h$ variable definition; and by replacing the phrase ''megawatts or 1000 lb/hr of steam'' with the phrase ''megawatts, 1000 lb/hr of steam, or mmBtu/hr thermal output'' in the L_h variable definition, in paragraph (c) of section 2.1.7.2;

g. Replacing ''D4177–82 (Reapproved 1990)'' with ''D4177–95 (2000)'', in the first sentence of section 2.2.3;

h. Replacing ''D4057–88'' with ''D4057–95 (2000)'', 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. Replacing the identifier ''D1826–88'' with the identifier ''D1826–94 (1998)'', by replacing the identifier ''D3588–91'' with the identifier ''D3588–98'', by adding the number ''(2001)'' after the identifier ''ASTM D4891–89'', by replacing the numbers ''2172–86'' with the numbers ''2172–1996'', and by replacing the numbers ''2261–90'' with the numbers ''2261–1999'', in section 2.3.4;

m. Adding two sentences at the end of section 2.3.4.1;

n. Replacing the phrase ''Gas Total Sulfur Content'' in the ''Parameter'' column of Table D–6 with the phrase ''Gas Total Sulfur Content*'', and adding the following footnote beneath the Table '' * Required no later than July 1, 2003''; and

o. Replacing the words ''(Reapproved 1990)'' with the words ''(1997)e1'' in section 3.2.2.

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–1989 (Reaffirmed 1995) (''Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi''); ASME MFC–4M–1986 (Reaffirmed 1990), ''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 2001) (''Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters''); ASME MFC–6M–1998 (''Measurement of Fluid Flow in Pipes Using Vortex Flow Meters''); ASME MFC–7M–1987 (Reaffirmed 2001), ''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 Measurement Standards, Chapter 4: Section 2, ''Conventional Pipe Provers'' (Provers Accumulating at Least 10,000 Pulses), Measurement Coordination (Second Edition, March 2001), Section 3, ''Small Volume Provers'' (First Edition), and Section 5, ''Master-Meter Provers'', Measurement Coordination (Second Edition, May 2000); 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 (incorporated by reference under § 75.6). 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.

* * * * *

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 X-Ray Spectrometry,'' or ASTM D4294–98, ''Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy'' (incorporated by reference under § 75.6).

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(2000)e1, ''Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method),'' ASTM D1217–93(1998), ''Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer,'' ASTM D1481–93 (1997), ''Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary,'' ASTM D1480–93 (1997), ''Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer,'' ASTM D1298–99, ''Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method,'' or ASTM D4052–96 (2002)e1, ''Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter'' (incorporated by reference under § 75.6).

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240–00 (Reapproved 1991), ''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 D5865–01ae1, ''Standard Test Method for Gross Calorific Value of Coal and Coke'' (incorporated by reference under § 75.6) or any other procedures listed in section 5.5 of appendix F of this part.

* * * * *

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 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 the GCV or percent methane requirement is met and if ≥ 98 percent of the 100 (or more) samples have a total sulfur content of 0.5 grains/100 scf or less; 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 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 GCV or percent methane requirement is met and 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. 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 D1072–90(1999), ''Standard Test Method for Total Sulfur in Fuel Gases,'' ASTM D4468–85 (2000) ''Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Radiometric 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 Liquified Petroleum Gases by Ultraviolet Fluorescence,'' or ASTM D3246–96 ''Standard Test Method for Sulfur in Petroleum Gas By Oxidative Microcoulometry'' (incorporated by reference under § 75.6).

* * * * *

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, for the purposes of implementing paragraph (c) in section 2.3.7 of this appendix, consider the latest date of any of the individual GCV samples used in the monthly average to be the ''date on which the sample was taken''.

* * * * *

41. Appendix E to Part 75 is amended by:

a. Adding a new sentence to the end of section 2.1;

b. Replacing the words ''section 5.1'' with the words ''section 8.3.1'' in section 2.1.2.1;

c. Replacing the phrase ''(MWge or steam load in 1000 lb/hr)'' with the phrase ''(MWge or steam load in 1000 lb/hr, or mmBtu/hr thermal output)'', in section 2.4.1;

d. Revising section 2.5.2; and

e. 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.

* * * * *

2.5.2 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 section.

* * * * *

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.

42. Appendix F to Part 75 is amended by:

a. Removing the second and third sentences from the introductory text of section 2;

b. Replacing the phrase ''method 19 in appendix A of part 60 of this chapter'' with 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. Adding ''(1997)e1'' after the identifier ''D3176–89'', by replacing the identifier ''D5291–92'' with the identifier ''D5291–01'', by replacing the identifier ''D1945–91'' with the identifier ''D1945–96 (2001)'', and by adding the number ''(2000)'' after the identifier ''D1946–90'', in section 3.3.6.1;

i. Revising section 3.3.6.2;

j. Revising the definition of ''X_i'' under Equation F–8 in section 3.3.6.4;

k. 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;

l. Revising section 4.4.1;

m. Removing the second and third sentences from the $\%CO_{2w}$ variable definition in 5.2.1;

n. Removing the second and third sentences from the $\%CO_{2d}$ variable definition in 5.2.2;

o. 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;

p. Removing the second and third sentences from the $\%O_{2d}$ variable definition, in section 5.2.4;

q. Replacing the identifier ''D240–87'' with the identifier ''D240–00'', by replacing the identifier ''D2015–91'' with the identifier ''D5865–01ae1'', and by replacing the identifier ''D2382–88'' with the identifier ''D4809–00'' in the GCV_O variable definition, in section 5.5.1;

r. Replacing the identifier ''D1826–88'' with the identifier ''D1826–94 (1998)'', by replacing the identifier ''D3588–91'' with the identifier ''D3588–98'', by adding the number ''(2001)'' after the identifier ''D4891–89'', by replacing the numbers ''2172–86'' with the numbers ''2172–1996'', and by replacing the numbers ''2261–90'' with the numbers ''2261–1999'' in the GCV_g variable definition, in section 5.5.2;

s. Replacing each identifier ''D2234–89'' with the identifier ''D2234–00e1'', in section 5.5.3.1;

t. Revising section 5.5.3.2;

u. Revising the words ''as measured by ASTM D3176–89, D1989–92, D3286–91a, or D2015–91, Btu/lb'' to read ''as measured by ASTM D3176–89 (1997)e1, or D5865ae1, Btu/lb.'' in the definition of the GCV_c variable in Equation F–21;

v. Revising the word ''lb/hr'' to read ''lb/hr, or mmBtu/hr'' in the definition of the SF variable in Equation F–21b;

w. Revising the title and text of section 7;

x. 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;

y. Revising sections 8.1 and 8.1.1;

z. Revising section 8.2;

aa. Adding sections 8.2.1 and 8.2.2;

bb. Revising section 8.3;

cc. Revising section 8.4; and

dd. 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 D388–99e1):		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Sub-bituminous	9,819	1,840
Lignite	9,860	1,910
Petroleum Coke	9,832	1,853
Tire Derived Fuel 1	10,261	1,803
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.

* * * * *

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).

* * * * *

3.3.6.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D5865–01ae1 ''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 (Specific Gravity) of Gaseous Fuels,'' ASTM D4891–89 (2001) ''Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion,'' GPA Standard 2172–1996 ''Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis,'' GPA Standard 2261–1999 ''Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,'' or ASTM D1826–94 (1998), ''Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter'' for gaseous fuels, as applicable. (These methods are incorporated by reference under § 75.6).

* * * * *

3.3.6.4 * * *

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.

* * * * *

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 F_C-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–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 hour where Equation F–17 results in a negative hourly heat input rate, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

* * * * *

5.5.3.2 Use ASTM D2013–01, ''Standard Method of Preparing Coal Samples for Analysis,'' for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865–01ae1, ''Standard Test Method for Gross Calorific Value of Coal and Coke'' (All ASTM methods are incorporated by reference under § 75.6 of this part.)

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 owner 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)

$$M_{(NO_X)_h} = ER_{(NO_X)_h} HI_h t_h \qquad (\text{Eq. F-24})$$

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 of appendix A 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).

$$E_{(NO_X)h} = ER_{(NO_X)_h} HI_h \qquad (\text{Eq. F-24a})$$

Where:

$E_{(NO_X)h}$ = NO_X mass emissions rate in lbs/hr 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 of appendix A 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.)

$$E_{(NO_X)_h} = K\, C_{hw} Q_h \qquad (\text{Eq. F-26a})$$

Where:

$E_{(NO_X)h}$ = NO_X mass emissions rate in lb/hr.
K = 1.194×10^{-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:

$E_{(NO_X)h}$ = NO_X mass emissions rate, lb/hr.
K = 1.194×10^{-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:

$M_{(NO_x)h}$ = 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.

$$M_{(NO_X)_{\text{time period}}} = \frac{\sum_{h=1}^{p} M_{(NO_X)_h}}{2000} \qquad \text{(Eq. F-27)}$$

Where:

$M_{(NO_X)_{\text{time period}}}$ = NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(NO_x)h}$ = 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.

$$M_{(NO_X)_{\text{time period}}} = \frac{\sum_{h=1}^{p} E_{(NO_X)_h} t_h}{2000} \qquad \text{(Eq. F-27a)}$$

Where:

$M_{(NO_X)_{\text{time period}}}$ = 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

* * * * *

43. Appendix G to Part 75—is amended by:

a. Revising section 2.1.2;

b. Replacing the identifier ''D3174–89'' with the identifier ''D3174–00'' in section 2.2.1; and

c. Adding the number ''(1997)'' after the identifier ''D3178–89'' in section 2.2.2.

The revisions and additions 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 (1997) or ASTM 5373–93 for coal; ASTM D5291–01 ''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 (2000)e1 and either ASTM D2502–92 (1996) or ASTM D2503–92 (1997) for oil; and computations based on ASTM D1945–96 (2001) or ASTM D1946–90 (2000) for gas.

* * * * *

44. Appendix K to Part 75 is amended by:

a. Adding a sentence to the end of section 7.2.3; and

b. Revising Table K–1 of section 8.

c. Adding the number ''2'' after the words ''sections 1 and'' in the definition of the variable M* in Equation K–5.

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 lead check is passed.
Post-test leak check	≤4% of average sampling rate	After sampling	Sample invalidated.**
Ratio of stack gas flow rate to sample flow rate.	Maintain within ± 25% of initial ratio from first hour of data collection period.	Every hour throughout data collection period.	Sample invalidated if more than 5% of the hourly ratios or 5 hourly ratios (whichever is less restrictive) are not maintained within the acceptance criteria.**
Sorbent trap section 2 breakthrough.	≤5% of Section 1 Hg mass	Every sample	Sample invalidated.**
Paired sorbent trap agreement	≤10% Relative Deviation (RD) if the average concentration is >1.0 μg/m³, and ≤20% RD if the average concentration is ≤1.0 μg/m³.	Every sample	Either invalidate the data from the paired traps or report the results from the trap resulting in 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.
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	Sample invalidated.**
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.
Dry gas meter calibration (At 3 orifice initially, and 1 setting thereafter).	Calibration factor (Y) within ±5% of average value from the initial (3-point) calibration.	Prior to initial use and at least quarterly thereafter.	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.

** However, if only one of the paired samples fails to meet this specification and the other sample meets all of the applicable QA criteria, the results of the valid sample may be used for reporting under this part, provided that the measured Hg concentration is multiplied by a factor of 1.222. If both samples are invalidated and quality-assured data from a certified backup monitoring system, reference method, or approved alternative monitoring system are unavailable, substitute data must be used.

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