ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72, 75, 78, and 97

[FRL–6984–8]

RIN 2060–AJ43

Revisions to the Federal NO_X Budget Trading Program, the Emissions Monitoring Provisions, the Permits Regulation Provisions, and the Appeal Procedures

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing rule revisions that would modify the existing requirements for sources affected by the Federal NO_X Budget Trading Program, the Acid Rain Program, and the October 27, 1998 NO_X SIP Call. The proposed revisions would streamline and add flexibility to the monitoring and reporting requirements in response to the significant changes that have occurred in power generation in recent years due to deregulation and recent environmental actions initiated by EPA to reduce nitrogen oxides emissions. This proposed action would also make certain technical corrections, remove outdated provisions, and correct printing, typographical, and grammatical errors to correct or clarify cross references, and, in a few instances, to ensure that the specific rule language is consistent with the Agency's intent.

DATES: Comments. All public comments must be received on or before July 30, 2001.

Public Hearing. Anyone requesting a public hearing must contact EPA no later than June 25, 2001. If a hearing is held, it will take place June 27, 2001, beginning at 10 a.m.

ADDRESSES: *Comments.* Comments must be mailed (in duplicate if possible) to: EPA Air Docket (6102), Attention: Docket No. A–2000–33, Room M–1500, Waterside Mall, 401 M Street, SW., Washington, DC 20460.

Public Hearing. If a public hearing is requested, it will be held at the Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460, in the Education Center Auditorium. Refer to the Clean Air Markets homepage at www.epa.gov/airmarkets for more information or to determine if a public hearing has been requested and will be held.

Docket. Docket No. A–2000–33, containing supporting information used to develop the proposal, is available for public inspection and copying from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section at the above address.

FOR FURTHER INFORMATION CONTACT: Gabrielle Stevens, Clean Air Markets Division (6204N), U.S. Environmental Protection Agency, Ariel Rios Building, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, telephone number (202) 564–2681 or the Acid Rain Hotline at (202) 564–9620. Electronic copies of this document and technical support documents can be accessed through the EPA Web site at: http://www.epa.gov/airmarkets.

SUPPLEMENTARY INFORMATION: In accordance with titles I and IV of the Clean Air Act (CAA or the Act), EPA is proposing rule revisions to support previous actions the Agency has taken to mitigate interstate transport of nitrogen oxides as well as to reduce the acidic deposition precursor emissions of sulfur dioxide and nitrogen oxides (NO_X). Title I of the CAA, as amended by the Clean Air Act Amendments of 1990, authorizes EPA, under section 126 of the Act, to require reductions of NO_X emissions from sources that emit in violation of the CAA prohibition against significantly contributing to ozone nonattainment or maintenance problems in a downwind State that petitions EPA for relief. On January 18, 2000, EPA published a section 126 finding that a number of large electric generating units and large industrial boilers and turbines named in petitions filed by several northeastern States emit NO_X in violation of the CAA. In that same notice, the EPA finalized the Federal NO_X Budget Trading Program as the control remedy for sources affected by the rule. EPA originally promulgated 40 CFR parts 72, 75, and 78 on January 11, 1993, to implement the Acid Rain Program as authorized by title IV of the Act. EPA has subsequently promulgated several final rules revising the January 11, 1993 rules. The most recent revisions were promulgated on May 26, 1999. Finally, note that although today's proposal will not revise the Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group for Purposes of Reducing the Transport of Ozone (NO_X SIP call), promulgated on October 27, 1998, under section 110 of the Act, the proposed changes to the monitoring and reporting provisions of 40 CFR part 75 (and related changes to certain definitions in 40 CFR part 72) will affect sources that are subject to the NO_X SIP call, since many of these sources will be required to implement part 75 emissions monitoring.

The provisions of 40 CFR parts 72, 75, 78, and 97 will be revised to modify the existing requirements for sources affected by the Acid Rain Program, the Federal NO_X Budget Trading Program, and the October 27, 1998, NO_X SIP call. Today's proposal is limited to the specific provisions in parts 72, 75, 78, and 97 identified and discussed here. EPA is not considering reopening or requesting public comment on any other provisions of parts 72, 75, 78, or 97 or of the section 126 or NO_X SIP call rulemaking.

A redline/strikeout version of 40 CFR parts 72 and 75 as amended by this proposed rule is available in the Docket and on the EPA Web site referenced above. The contents of the preamble are listed in the following outline:

I. Regulated Entities

Entities regulated by this action are fossil fuel-fired boilers, turbines, and combined cycle units that serve generators which produce electricity, generate steam, or cogenerate electricity and steam. While part 75 primarily regulates the electric utility industry, certain State and Federal NO_X mass emission trading programs may rely on subpart H of part 75, and those programs may include boilers, turbines, and combined cycle units from other industries. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	(1) Electric service providers (2) Process sources with large boilers and turbines 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 the 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 of this preamble.

II. Background and Summary of the Proposed Rule

Today's proposed action modifies existing monitoring and reporting requirements in 40 CFR parts 72 and 75 that support emission control programs that use the monitoring and reporting provisions of part 75 such as the Acid Rain Program and State NO_X reduction programs developed in response to the October 27, 1998, NO_X SIP call. The emphasis of these revisions is three-fold: (1) To streamline the rule by eliminating outdated sections; (2) to make technical corrections and clarifications to the rule; and (3) to add flexibility to the monitoring and reporting requirements. The most substantive proposed changes are as follows: the definitions of ''pipeline natural gas'' and ''natural gas'' in § 72.2 would be revised to remove all references to the H_2S content of the fuel and would instead be based on total sulfur content (corresponding changes would be made to appendix D to part 75); the compliance and certification timelines for certifying monitoring systems would be made the same for new units, newly affected units, deferred units, and new stacks; the low mass emissions (LME) units provisions in § 75.19 would be clarified; for units with certain types of NO_X emission controls, qualification as a LME unit would be made easier; the CEMS missing data procedures would be revised to allow fuel-specific missing data substitution as well as the use of a controlled and uncontrolled database for units with add-on emission controls; the missing data procedures in subpart H of part 75 would be expanded and clarified for sources that report emission data only in the ozone season; the NO_X span and range provisions in appendix A would be revised to make them more realistic and easier to implement for combustion turbines; and the alternate calibration error limit for daily operation would be tightened from 10 ppm to 5 ppm for units with span values of 50 ppm or less. Many of the above changes to part 75 would affect the monitoring and reporting sections of the part 97 rule. Therefore, today's proposed rule would also revise certain sections of part 97 to make the monitoring and reporting sections of the part 75 and part 97 rules consistent. In addition, certain miscellaneous changes would be made to clarify or correct minor errors in other sections of part 97 or to make the administrative appeal procedures in part 78 applicable to decisions of the Administrator under part 97.

III. Detailed Discussion of Proposed Revisions

A. Rule Definitions

EPA policy guidance and the instructions EPA has developed for monitoring and electronic reporting under part 75 rely on many terms that are used in part 75 but that are not defined in § 72.2 (the definitions section for all Acid Rain Program regulations). Also, some of the existing definitions in § 72.2 are incorrect or incomplete. To address these concerns, the proposed revisions would add or modify several definitions.

1. How Does EPA Propose To Revise the Definitions of Pipeline Natural Gas and Natural Gas in § 72.2?

Background. Following the May 26, 1999, rulemaking, a utility group sued EPA over the definitions of ''pipeline natural gas'' and ''natural gas'' contained in § 72.2. The issue is that gaseous fuel must meet a two-fold requirement to qualify as one of these fuels. In the current rule, there is an H_2S content limit (0.3 gr/100 scf for pipeline natural gas and 1.0 gr/100 scf for natural gas) and a requirement that H_2S constitute more than 50 percent of the total fuel sulfur content. Appendix D to the rule does not explain how to comply with the second of these two requirements (the H_2S as a percentage of total sulfur requirement). Further, industry members are concerned that this requirement cannot be implemented in a fair and consistent manner. For example, a very clean fuel with 0.1 gr/100 scf of H_2S and 0.3 gr/100 scf of total sulfur would not qualify as pipeline natural gas, because H_2S is less than 50 percent of the total sulfur content, but a fuel with three times more H_2S and twice as much total sulfur (0.3 gr/100 scf of H_2S and over 0.6 gr/100 scf of total sulfur) would qualify as pipeline natural gas under the current rule. In response to the industry's concerns, EPA recently issued guidance on how to demonstrate compliance with the H_2S content limit. As explained in the guidance, EPA also granted a petition allowing owners or operators to meet total sulfur limits in lieu of the H_2S percent of-total-sulfur requirement.

Discussion of Proposed Changes. The proposed rule would revise the definitions of ''pipeline natural gas'' and ''natural gas'' in § 72.2. All references to H_2S content would be removed and these fuels would be defined in terms of total sulfur content. For the purposes of determining SO_2 emissions, it makes no difference whether the fuel's sulfur is in the form of H_2S or any other form. The proposed total sulfur content values are 0.5 gr/100 scf or less for pipeline natural gas and 20.0 gr/100 scf or less for natural gas. EPA chose the value of 0.5 gr/100 scf for pipeline natural gas so that typical supplies of pipeline natural gas that have an average sulfur content of 0.2 to 0.3 gr/100 scf will consistently yield samples below this cutoff of 0.5 gr/100 scf. In addition, SO_2 emission rates calculated using this value will not be much higher than the rate of 0.0006 lb SO_2 /mmBtu for pipeline natural gas that EPA used to compute allocations for sources combusting pipeline natural gas. The value of 20.0 gr/scf is the maximum total sulfur content allowed under most contracts for transmitting pipeline natural gas and allowed under most tariffs established with the Federal Energy Regulatory Commission.

In addition, appendix D, sections 2.3.1.4 and 2.3.2.4 would be revised to require initial and periodic sampling to document the total sulfur content of the fuel. The revised rule would require periodic sampling on a semiannual basis, as well as whenever it is reasonable to believe that the composition of the fuel supply has changed. For fuels that qualify as pipeline natural gas, the 0.0006 lb/mmBtu default SO_2 emission rate would be used, and for fuels that qualify as natural gas, an SO_2 emission rate would be calculated based on Equation D–1h in appendix D. Note that Equation D–1h would be revised to be based upon the total sulfur content of the fuel, rather than the H_2S content.

2. How Does EPA Propose To Change the Definitions of Unit and Stack Operating Hours?

Background. The current rule allows quality-assurance (QA) test exemptions and deadline extensions for continuous emission monitors, based on the amount of unit operation. Grace periods are also allowed to complete missed QA tests. To qualify for QA test extensions and exemptions, an owner or operator must determine whether there are at least 168 unit or stack operating hours in the quarter (so that the quarter meets the definition of a ''QA operating quarter''). The length of grace periods is also determined on a unit or stack operating hour basis. The rule defines ''unit operating hour'' and ''stack operating hour'' in such a way that partial operating hours are counted as full hours. This is counterintuitive to the way that source operators normally count operating hours. They normally count cumulative operating time so that 30 minutes of operation equals 0.5 operating hours, not 1.0 hours.

Discussion of Proposed Changes. Definitions of ''cumulative stack operating hours'' and ''cumulative unit operating hours'' would be added to § 72.2. The definitions of ''QA operating quarter'' and'' fuel flowmeter QA operating quarter'' would be revised to put them in terms of cumulative unit or stack operating hours. Finally, all references to the length of grace periods would be changed to be in terms of cumulative unit operating hours or cumulative stack operating hours.

3. What Other Definitions Would Be Revised or Added to the Rule?

Background. There are several definitions in § 72.2 that are either unclear or inconsistent with the way in which part 75 has been implemented. In addition, some terms that are used in the Acid Rain Program Policy Manual and the EDR v2.1 Instructions are not defined in the rule.

Discussion of Proposed Changes. Under the proposal, EPA would add definitions of ''common pipe,'' ''common pipe operating time,'' ''diluent cap value,'' ''fuel flowmeter system,'' ''fuel usage time,''''multiple stack configuration,'' ''stack operating time,'' and ''unit operating time.'' These terms are all used in part 75 and the accompanying guidance materials, but are not defined in § 72.2. EPA believes these terms should be defined because they are terms of art as used in various sections of part 75.

Finally, the definitions of ''continuous emission monitoring system or CEMS,'' ''emergency fuel,'' ''heat input,'' ''hour before and after,'' ''maximum potential NO_X emission rate,'' ''maximum rated hourly heat input,'' ''missing data period,'' ''monitor accuracy,'' ''stack operating hour,'' and ''unit operating hour'' would be revised. See the technical support document (Docket A–2000–33, Item II–A–2) for an explanation of these technical changes.

B. Certification Timeline Issues

1. What Is the Deadline for an Application for Initial Certification?

Background. The current rule specifies different monitor certification timelines in § 75.4, for new units, new stacks, and deferred units. New units must certify their monitors within 90 calendar days after the unit commences commercial operation. Similarly, for newly affected units, owners or operators have 90 calendar days from the date on which they become Acid Rain affected units to certify monitors. Also, when a new stack or flue gas desulfurization system (FGD) is constructed, the owner or operator has 90 calendar days from the date on which emissions first exit to the atmosphere through the new stack or FGD to install and certify continuous monitoring systems. However, for deferred units (affected units that were in cold-storage on their compliance deadline), owners or operators have either 45 operating days or 180 calendar days (whichever occurs first) to certify monitors after recommencing operation. The 90 calendar day timeline has proven to be problematic, particularly for new units that experience mechanical problems when they first begin operating. The deferred unit timeline has greater flexibility.

Discussion of Proposed Changes. EPA proposes to make all of the timelines the same for deferred units, new units, new stacks, and newly affected units. In all cases, the certification deadline would be the earlier of 90 unit operating days or 180 calendar days after the unit commences commercial operation or recommences operation. Paragraphs (b), (c), (d), and (e) of § 75.4 would be revised to incorporate this change. Corresponding changes would be made to 40 CFR 97.70, the monitoring and reporting sections of the January 18, 2000, final section 126 rule, in order to make the certification timelines in parts 75 and 97 consistent.

2. For an Appendix E Peaking Unit, When Is Initial Certification Required While Combusting the Backup Fuel?

Background. The current rule specifies in § 75.4(f) that for an appendix E unit for which certification testing prior to the applicable deadline has been done only while combusting the primary fuel, certification tests using backup fuel must be completed within 30 unit operating days after the backup fuel is first combusted following the certification deadline.

Discussion of Proposed Changes. The proposal would revise § 75.4(f) to state that certification is required within the earlier of 90 unit operating days or 180 calendar days after the backup fuel is first burned following the initial certification deadline. This revised timeline is consistent with the changes to the timelines in § 75.4, paragraphs (b), (c), (d), and (e) in today's proposed rule.

3. What Happens if a Unit Loses Peaking, Gas-Fired, or LME Status?

Background. Under the current rule, when an appendix E unit loses its status as a peaking unit, a NO_X CEMS must be installed by December 31 of the following calendar year. Similarly, loss of gas-fired unit status requires (in some cases) installation of a COMS by December 31 of the following year. Loss of low mass emissions (LME) unit status under § 75.19 requires monitoring systems to be installed within two quarters after the quarter in which LME status is lost. The LME requirement appears to be inconsistent with the others in that it contains a shorter timeline to install and certify monitoring systems. In addition, when peaking unit or LME status is lost, the rule does not provide specific instructions regarding what emission values to report if the deadline for certifying monitors is not met.

Discussion of Proposed Changes. For units that lose their LME status, EPA proposes to change the deadline in § 75.19(b)(2) for monitor certification to December 31 of the year after the year in which the unit exceeded the LME applicability threshold(s), thus making the monitor certification timeline the same as the timelines in §§ 75.12(d)(2) and 75.14(c) for, respectively, loss of peaking unit status and loss of gas-fired status. In the period from the time of loss of LME status until the certification deadline, units would continue to monitor and report in accordance with the provisions for LME units.

Today's proposed rule also includes provisions in §§ 75.19(b)(2), 75.12(d)(2), 75.71(d), and appendix E, section 1.1 that would specify the emission reporting requirements when LME status or peaking unit status is lost and the monitor certification deadline is not met. For loss of peaking unit status, the maximum potential NO_X emission rate would be reported after the CEM certification deadline. For loss of LME status, SO_2 and CO_2 emissions would be reported after the deadline using the applicable LME default emission rate and the maximum potential hourly heat input, and NO_X emissions would be reported using the fuel specific maximum potential NO_X emission rate.

C. Missing Data

1. How Will the Proposed Rule Affect the Missing Data Procedures in §§ 75.31 Through 75.37 for Units That Produce Electrical or Thermal Output?

Background. The part 75 CEMS missing data procedures in §§ 75.31 through 75.37 require the use of substitute data values for each unit operating hour in which quality-assured data are not obtained, either from a certified CEMS, a reference method, or an approved alternative monitoring system. The method of determining the appropriate substitute data values depends principally on two things: (1) The length of the missing data period; and (2) the percent monitor data availability at the end of the missing data period. In some cases, the substitute data value is simply the arithmetic average of the CEMS hourly averages recorded before and after the missing data period. In other cases, the substitute data value is either the 90th percentile value, the 95th percentile value, or the maximum value in a historical lookback period consisting of a certain number of quality-assured monitor operating hours (the previous 720 hours of quality-assured data for SO_2, CO_2, and moisture, and the previous 2,160 hours of quality-assured data in a particular load range (''load bin'') for NO_X and flow rate). Finally, if, at the time of the missing data period, the percent monitor data availability is below 80 percent, the appropriate maximum potential value must be reported for each hour of the missing data period.

The part 75 missing data procedures do not take into consideration the type of fuel combusted. Rather, a single database of quality-assured monitor operating hours is maintained for each monitored parameter (SO_2, NO_X, flow rate, etc.) in order to provide substitute data values when a historical lookback is required. For a unit that combusts different types of fuel having significantly different emission levels for a particular parameter (e.g., for a unit which can burn either coal or natural gas, the SO_2 emissions are much higher when coal is burned), the substitute data values obtained in a historical lookback may not be representative of the actual emissions during the missing data period.

For units with add-on SO_2 or NO_X emission controls, § 75.34 in the current rule allows three missing data options. The owner or operator may either: (1) Use the standard missing data procedures, if the controls are documented to be operating properly, or otherwise use maximum potential values; or (2) petition the Administrator to use the maximum controlled emission rate recorded in the previous 720 quality-assured monitor operating hours, if the percent monitor data availability is below 90 percent and if the controls are documented to be operating properly during the missing data period; or (3) petition the Administrator to use site-specific parametric monitoring procedures for missing data substitution. These missing data options have proven to be difficult to implement and lack flexibility. The representativeness of the substitute data values derived from these procedures, particularly for Options (1) and (3), is also uncertain.

Option (1) requires parametric data to be recorded during missing data periods to document proper operation of the add-on emission controls, in order to justify using the standard missing data procedures. The parameters selected and the acceptable ranges for the parameters must be documented in the QA plan for the unit. The designated representative must submit a certification statement in the electronic quarterly report, affirming that the emission controls operated within the acceptable parametric ranges during each missing data period and that use of the standard missing data procedures is appropriate. This approach to missing data substitution is problematic because currently there are no clear guidelines, either in the rule or in EPA policy guidance, for selecting the appropriate parameters or the acceptable parametric ranges. Therefore, it is difficult to establish whether the emission controls are actually working properly during a missing data period, even if parametric data have been recorded and are available for auditing purposes. Further, when the standard missing data procedures are used, the substitute data values derived from historical lookbacks may not be representative of the actual emissions during the missing data period, because the historical databases used for the lookbacks include all quality-assured CEMS data, for both controlled and uncontrolled operation.

Option (2), above, is difficult to implement administratively, because it requires a petition every time the owner or operator wants to use a missing data value based solely on data recorded during hours when the emission controls were working, instead of using the standard missing data routines. Use of this missing data option could therefore require a petition to be submitted to and answered by EPA every quarter.

To date, no units in the Acid Rain Program have petitioned to use Option (3), above.

Discussion of Proposed Changes. Today's proposed rule would revise the part 75 missing data procedures to allow missing data substitution to be done on a fuel-specific basis. Also, for units with add-on SO_2 or NO_X emission controls, EPA proposes to revise § 75.34 to include a new missing data option, based on the operating status of the emission controls. Note that the use of these new rule provisions would be optional. Therefore, sources using the missing data provisions in the current rule could continue to do so.

Today's proposed rule would add fuel-specific missing data provisions to § 75.33, in five new paragraphs, (b)(5), (b)(6), (c)(7), (c)(8), and (c)(9). These provisions would allow the owner or operator to create and maintain separate databases for each type of fuel combusted in the unit, for missing data purposes. Substitute data values would be derived from the appropriate database, depending on the type of fuel being burned during the missing data period. To use these new provisions, the owner or operator would be required to determine fuel-specific maximum potential values for concentration, emission rate, or flow rate (as applicable).

The owner or operator would be allowed to switch to the new fuel-specific missing data procedures at any time. Until the requisite number of hours of quality-assured fuel-specific data were recorded for the lookback periods (either 720 or 2,160 hours), the owner or operator would use all available data in the databases for the lookbacks.

For units with add-on controls, the proposed rule would retain the missing data option in § 75.34(a)(3), allowing the owner or operator to petition to use a site-specific parametric missing data substitution procedure. The owner or operator could also continue using the missing data option in § 75.34(a)(1), which allows the standard missing data procedures to be used for hours in which proper operation of the emission controls is documented by means of parametric data, and requires maximum potential values to be reported for all other missing data hours. Note, however, that the proposed rule would expand and clarify the way in which parametric data are used to document proper operation of the add-on emission controls, as explained below in the discussion of the changes to § 75.34(a)(2).

Today's proposed rule would significantly revise § 75.34(a)(2), to allow the owner or operator of a unit with add-on SO_2 or NO_X emission controls (including units equipped with dry low- NO_X technology) to create and maintain two separate databases, controlled and uncontrolled, for missing data purposes. Any hour in which the add-on controls are documented to be operating (on) would be included in the controlled database. Any hour in which the controls are not operating (off) would be included in the uncontrolled database. For units with more than one type of add-on controls (e.g., steam injection plus SCR), hours in which any of the add-on controls operate would be included in the controlled database. Alternatively, the uncontrolled database could consist of either: (a) quality-assured data recorded by a certified monitor at the control device inlet; or (b) for a unit with a main stack and a bypass stack, quality-assured data recorded by a certified monitoring system installed on the bypass stack.

If the proposed missing data option in § 75.34(a)(2) were selected, then, whenever a historical lookback was required, the substitute data value for each hour of the missing data period would be taken from the appropriate database (controlled or uncontrolled), depending on whether the emission controls are documented (by means of parametric data) to be operating properly during the hour. For the SO_2 missing data algorithms in § 75.33, paragraphs (b)(1)(i) and (b)(2)(i), which require the hour before and hour after average value to be reported rather than performing a historical lookback, proposed § 75.34(a)(2) would restrict the use of the hour before and hour after value to missing data hours in which the emission controls are documented to be operating properly; otherwise, the maximum uncontrolled value recorded in the previous 720 hours would be reported. The owner or operator would be required, under § 75.58(b)(3), to keep records of the operational status (on or off) of the emission controls for all unit operating hours, and to keep records of the parametric data recorded during periods of missing SO_2 or NO_X data. The designated representative would also be required to submit a certification statement in the quarterly report, verifying that the add-on controls were operating properly during each missing data hour in which substitute values from the controlled database were reported, or, for SO_2, each missing data hour in which the average of the hour before and hour after values was reported.

The owner or operator of a unit with add-on emission controls would be allowed to switch to the missing data procedures in § 75.34(a)(2) at any time. If, at the time of the change, the standard missing data procedures of § 75.33 are already in use, and if hourly calculation of percent monitor data availability (PMA) is being performed according to § 75.32, it would not be necessary to repeat the initial missing data procedures of § 75.31. Rather, calculation of the PMA could continue uninterrupted and the two emission databases (controlled and uncontrolled) could be created prospectively. Alternatively, the databases could be created from historical CEM data, if records are available to document the operating status (on or off) of the add-on controls during each quality-assured monitor operating hour. Until the requisite number of hours of quality-assured data for the lookback periods are recorded (i.e., either 720 or 2,160 hours), the owner or operator would use all available data in each database for the lookbacks.

Section 75.34(d) of the proposed rule would expand and clarify the way in which parametric data are used to document proper operation of add-on emission controls during periods of missing SO_2 or NO_X data. According to § 75.58(b)(3)(ii) of the current rule, ''proper operation'' of the controls means that parametric data were recorded during the missing data period, indicating that, ''all parameters * * * [were] * * * within the ranges specified in the quality assurance/quality control program.'' EPA believes that in view of today's proposed substantive changes to § 75.34, this regulatory language is inadequate, because it gives no guidelines concerning which parameters to monitor or how to determine the acceptable parametric ranges.

EPA therefore proposes to revise § 75.34(d), as follows. The owner or operator of a unit with add-on controls would, for missing data purposes, still be required (as in the current rule) to document in the QA/QC program for the unit the parameter(s) monitored and the acceptable parametric ranges and combinations of parameters which indicate proper operation of the emission controls. However, for units that use a control method involving injection of water, steam, or chemical reagents into the combustion chamber or flue gas stream (e.g., limestone injection, limestone scrubbing, water injection, steam injection, SCR, or SNCR) today's proposed rule would require at least one key parameter to be monitored during missing data periods, to document proper emission control operation. A key parameter would be one that has a direct relationship to control device removal efficiency, such as the water-to-fuel ratio, the ammonia injection rate, or the slurry flow rate.

Further, proposed § 75.34(d) would require the owner or operator to establish a demonstrable correlation between the parametric data and control device removal efficiency, as part of the QA/QC program for the unit. The correlation would be based on parametric data recorded during unit operation, when the add-on controls are in-service and the SO_2 or NO_X monitor at the control device outlet is providing quality-assured data. The correlation would be derived from a minimum of 720 hours of data, obtained at various load levels, representing the range of operation of the unit. The correlation would serve as the basis for determining whether substitute data values should be taken from the controlled database or from the uncontrolled database during periods of missing SO_2 or NO_X data. Finally, the owner or operator would be required to provide to EPA or to the State, upon request, either the parametric data recorded during missing data periods or the related QA/QC program information (or both).

EPA believes that the new proposed missing data option in § 75.34(a)(2), which conditionally allows the use of substitute data values taken from a controlled database, would be sufficiently protective of the environment, for two reasons. First, if the add-on controls were not working properly when flagged as being on, emissions would be higher than normal. These high emission values would be recorded by the CEMS and would become part of the controlled database. This would result in conservatively high substitute data values being obtained from the historical lookbacks and applied to controlled missing data hours. Second, the proposed revisions to § 75.34(d), requiring the owner or operator to monitor key parameters for certain types of controls and to develop an actual correlation between the parametric data and the removal efficiency of the control device, would provide reasonable assurance that the emission controls are operating properly during missing data periods.

2. How Will Subpart H Missing Data Provisions Be Affected for Units That Produce Electrical or Thermal Output?

Background. The missing data procedures for subpart H units are specified in §§ 75.70(f) and 75.74(c)(7). Section 75.70(f) requires the missing data procedures in subpart D of part 75 (§§ 75.31 through 75.37) to be used for sources that report emission data on a year-round basis. Section 75.74(c)(7) also requires subpart H sources that report data on an ozone season-only basis to use the missing data procedures of subpart D, except that: (1) Only data from within the ozone season are to be used in the historical lookbacks; and (2) when a fuel combusted in the current ozone season has a higher NO_X emission rate than the fuel(s) burned in the previous ozone season, or when a unit's add-on controls are not working properly (as indicated by recorded parametric data), the maximum potential NO_X emission rate (MER) must be reported.

Discussion of Proposed Changes. Because owners and operators of subpart H units are required to use the initial and standard missing data procedures in §§ 75.31 through 75.37, all of today's proposed changes to those sections would apply to subpart H units. Therefore, the owner or operator of a subpart H unit could elect to use either the new fuel-specific missing data procedures in § 75.33 or, for units with add-on emission controls, the new missing data procedure in proposed § 75.34(a)(2).

Today's proposed rule would also revise § 75.74(c)(7), the section which provides the missing data procedures for subpart H sources that report emission data only during the ozone season, rather than on a year-round basis. EPA proposes to make three substantive revisions to that section.

First, § 75.74(c)(7)(ii) would be revised to require reporting of the MER only when sufficient, prior quality-assured NO_X emission data are not available for combustion of a new fuel that has a higher NO_X emission rate than any fuel burned in the previous ozone seasons. Once sufficient quality-assured emission data are obtained for the new fuel, it would no longer be necessary or appropriate to report the MER, as NO_X emission data for the new fuel would be in the missing data banks, and the standard, historical lookbacks could be used to provide representative substitute data values.

Second, EPA proposes to remove from § 75.74(c)(7)(ii) the requirement to report the MER when the NO_X emission controls are not working properly, as indicated by parametric data recorded under § 75.74(c)(8). The requirement to report the MER when the emission controls are not working properly is associated with the missing data option in § 75.34(a)(1) and is found in that section. Therefore, it is unnecessary to restate the requirement in subpart H. Since proposed § 75.74(c)(7)(ii) requires subpart H units that report data on an ozone season-only basis to use the missing data procedures in §§ 75.31

through 75.37, owners and operators of such units must follow the missing data provisions in § 75.34 if the units have add-on NO_X emission controls. This includes the provision in § 75.34(a)(1), if that missing data option is selected, requiring the MER to be reported when proper operation of the NO_X emission controls cannot be documented.

Third, today's proposed rule would add a new paragraph (iii), with subparagraphs (A) through (M), to § 75.74(c)(7), explaining how to apply the initial and standard part 75 missing data procedures in §§ 75.31 through 75.37 on an ozone season-only basis. EPA is adding these provisions to subpart H because the part 75 missing data routines are designed for sources that report emission data on a year-round basis. For example, for all of the part 75 standard missing data routines that use 720 or 2,160 hour historical lookbacks to determine the appropriate substitute data values, the databases for the lookbacks consist of quality-assured CEMS data that have been recorded throughout the year. Also, the percent monitor data availability (PMA) calculations described in § 75.32 are always based on a particular number of unit operating hours, either the number of unit operating hours since initial certification, or the number of unit operating hours in the past three years, or the previous 8,760 unit operating hours. The number of unit operating hours used in the PMA calculations includes operating hours from all four calendar quarters of the year.

Section 75.74, paragraph (c)(7)(i) clearly states that for subpart H sources that report data on an ozone season-only basis, only data from within the ozone season are to be included in the missing data routines. Thus, as written, the missing data procedures in subpart D of part 75, which use data from all twelve months of the year, are incompatible with the requirements of § 75.74(c)(7)(i). Despite this, EPA believes that there is a relatively simple way to resolve this inconsistency in the rule, as discussed in the following paragraphs.

Section 75.74, paragraph (c)(7)(iii) in today's proposed rule would modify the initial and standard part 75 missing data procedures in §§ 75.31 through 75.37 to adapt them to sources that report emission data only during the ozone season. This adaptation is possible because there is a commonality between year-round reporting and ozone season-only reporting—in both cases there is a discrete time period used for compliance determination. For year-round reporters, that time period is the calendar year, and for ozone season-only reporters, the compliance time period is the ozone season. This commonality allows the missing data instructions for ozone season-only reporters to be written in a parallel manner to the missing data procedures for year-round reporters.

Paragraphs (A) through (M) in proposed § 75.74(c)(7)(iii) provide the necessary parallel rule language to adapt the missing data provisions in §§ 75.31 through 75.37 to ozone season-only reporters. The following is a summary of the essential elements of these proposed rule provisions:

- Use of the initial missing data procedures in § 75.31 would commence with the first operating hour in the first ozone season for which emission reporting is required.
- For initial missing data purposes and for the historical data lookbacks required under § 75.33, phrases such as ''720 quality-assured monitor operating hours'' would be replaced with phrases such as ''720 quality-assured monitor operating hours within the ozone season.''
- For PMA calculations, phrases such as ''total unit operating hours'' would be replaced with ''total unit operating hours within the ozone season.'' Also, ''8,760 unit operating hours'' (the number of hours in a calendar year) would be replaced with ''3,672 unit operating hours'' (the number of hours in an ozone season).
- For both PMA calculations and historical lookbacks, the phrase ''three years (26,280 clock hours)'' would be replaced with ''three ozone seasons.''

3. What Are the Missing Data Requirements for Units That Do not Produce Electrical or Thermal Output?

Background. Today's proposed rule would add missing data procedures to part 75 for units that do not generate electricity or produce steam load. The new missing data provisions would be added to §§ 75.31 and 75.33, to appendix C of part 75, and to section 2.4 of appendix D. The rationale for these new provisions and a discussion of the provisions are presented in the following paragraphs.

As stated in Section II of this preamble, one of the main objectives of today's proposed rule is to modify the existing monitoring and reporting sections of parts 72 and 75 which support emission control programs that use the monitoring and reporting provisions of part 75, such as State NO_X reduction programs developed in response to the October 27, 1998 SIP call. Under the NO_X SIP call, States have the flexibility to include stationary sources other than electric generating units in their NO_X reduction plans. For example, the State of New York has proposed regulation 204 to control emissions of nitrogen oxides from stationary sources. The sources affected by this regulation include EGU and non-EGU sources, such as industrial boilers and cement kilns. To comply with sections 204–8 of this regulation, all of the affected units must monitor and report NO_X mass emissions according to subpart H of 40 CFR part 75, beginning on May 1, 2002. Other States, including New Jersey, Pennsylvania, Maryland, Delaware, and Massachusetts have proposed, or may be proposing, similar rules which require some non-electric generating units to monitor according to subpart H of part 75. To date, EPA has identified three non-EGU source categories that would likely be subject to part 75 monitoring and reporting under the various State rules: industrial boilers, refinery process heaters, and cement kilns.

At the request of the New York State Department of Environmental Conservation, EPA examined the part 75 monitoring provisions to assess whether these provisions are adequate for determining NO_X mass emissions from non-electric generating units. As a result of this assessment, EPA concluded that for industrial boilers, which produce thermal output (i.e., steam load) and which are very similar to electric utility boilers, no significant changes to the monitoring and reporting provisions of part 75 would be required. However, for cement kilns and refinery process heaters, which do not produce electricity or steam load, EPA has identified three key areas where modifications to the existing part 75 monitoring provisions would be necessary to allow full and complete monitoring of NO_X mass emissions. These areas are:

- Determination of the maximum potential concentration (MPC) for NO_X;
- The missing data routines for NO_X concentration, NO_X emission rate, stack flow rate, and fuel flow rate; and
- RATA load level requirements.

Discussion of Proposed Changes. To address the first issue (NO_X MPC determination), EPA is proposing to add default MPC values for process heaters and cement kilns to part 75. The selected MPC values and the rationale for them are found in section III.F.3 of this preamble. The third issue (RATA load level requirements) is discussed in detail in section III.F.10 of this preamble. To address the second issue (missing data routines), EPA is proposing to add non-load-based missing data procedures to part 75, as previously noted.

The missing data procedures in part 75 for NO_X, stack flow rate, and fuel flow rate are load-based. That is, all of the quality-assured hourly data recorded by part 75 NO_X monitors, flow monitors, and fuel flowmeters are segregated into load ranges (or ''bins''). The purpose of using the load bin approach is to ensure that representative substitute data values are provided during periods of monitor downtime (i.e., for each missing data hour, the appropriate substitute data value is taken from the corresponding load bin). However, for units that do not produce electrical or thermal output, the current part 75 missing data procedures for NO_X, stack flow rate, and fuel flow rate are inadequate.

The missing data procedures for non-load-based units in today's proposed rule are the result of discussions between EPA and representatives of the cement industry. The Agency had received a letter on August 20, 1999, from the American Portland Cement Alliance (APCA) (*see* Docket A–2000–33, Item II–D–1), containing a proposed methodology for performing missing data substitution for NO_X and flow rate at cement kilns. EPA responded to this draft proposal in a letter to APCA dated April 24, 2000 (*see* Docket A–2000–33, Item II–C–2). In that response letter, the Agency expressed agreement with some, but not all, of the provisions of APCA's proposal. The missing data approach outlined in today's proposed rule for non-load-based units reflects EPA's stated position in the April 24, 2000, letter to APCA.

The proposed non-load-based missing data routines are modeled after, and are much the same as, the existing routines for load-based units. However, there are two important differences:

- The owner or operator of a non-load-based unit would have the choice of either not using bins at all or using ''operational bins'' to segregate the quality-assured NO_X, stack flow rate, or fuel flow rate data; and
- For a non-load-based unit, the arithmetic average of the previous 2,160 quality-assured hours of NO_X concentration or NO_X emission rate (as applicable) would be used in the standard NO_X missing data routines, instead of the arithmetic average of the values from the hour before and hour after the missing data period.

The reason for allowing the use of operational bins is to give affected facilities the flexibility to customize their missing data routines, based on plant operational parameters and conditions that affect NO_X emissions, stack flow rate, or fuel flow rate. The procedures and requirements for defining operational bins are found in proposed new sections 3 and 4 of appendix C to part 75. The owner or operator would be required to provide a complete description of each operational bin in the hardcopy portion of the monitoring plan required under §§ 75.53(e)(2) (for NO_X and stack flow rate) or 75.53(f)(1)(ii) (for fuel flow rate). The description of each operational bin would include the unique combination of parameters and operating conditions associated with the bin and an explanation of the relationship between these parameters and conditions and the magnitude of the NO_X emissions, stack flow rates, or fuel flow rates. When using operational bins, it would be necessary to monitor the parameter(s) and operating conditions used to define the operational bin. For any hour in which essential operating or parametric data are unavailable and the operational bin could not be determined, the proposed non-load-based provisions in §§ 75.31 and 75.33 and section 2.4 of appendix D would require maximum potential values to be reported.

In response to a recommendation by the cement industry, EPA proposes to use the average of the previous 2,160 quality-assured hours of NO_X data in the standard missing data routines for non-load-based units instead of using the average of the hour before and hour after values. APCA advocated this approach in the previously mentioned missing data proposal that was sent to EPA on August 20, 1999. EPA agrees with APCA's position that hour-to-hour variability of NO_X emissions from a cement kiln is high, and using the hour before and hour after average could cause significant underestimation or overestimation of emissions.

4. How Will Today's Proposed Rule Revise the Procedures in Appendix C for Establishing Load Ranges (or ''bins'') for Missing Data Purposes?

Background and Discussion of Proposed Changes. Today's proposed rule will revise section 2.2.1 of appendix C to clarify the method of determining the maximum hourly average gross load (MHGL) for cogeneration units or other units for which some portion of the heat input is not used to produce electricity. The MHGL for such units would be determined by converting the maximum rated hourly heat input of the unit to an equivalent electrical output in megawatts. The maximum rated hourly unit heat input would include the maximum potential heat input from auxiliary combustion sources, such as duct burners or auxiliary boilers. The efficiency of the unit would be used in conjunction with the maximum unit heat input to calculate the MHGL. If the actual efficiency of a particular combustion source is unknown, a default efficiency of 50 percent would be used for a combustion turbine, and 33 percent for any other type of combustion source. Having established the maximum hourly gross load, the missing data load ranges would then be determined as percentages of the MHGL.

5. How Will the Maximum Potential Moisture Provision Be Revised?

Background. For units for which you continuously account for the stack gas moisture content with a moisture monitoring system, substitute data must be reported whenever an hourly moisture reading is missing. When a moisture monitoring system is uncertified, and when the percent monitor data availability for moisture drops below 80 percent, the maximum potential moisture percentage or the minimum potential moisture percentage must be reported (depending upon which emission and heat input rate equations are used). For the minimum potential moisture percentage, the rule specifies that the value may be determined from quality-assured CEM data or a default value of 3 percent H_2O may be used. However, to determine the maximum potential moisture percentage, the rule requires quality-assured CEM data to be used—no default value is specified.

Discussion of Proposed Changes. The proposal would add a second option to section 2.1.6 of appendix A, allowing the use of a default maximum potential moisture value of 16 percent H_2O. This revision would treat maximum and minimum potential moisture values on a consistent basis for substitute data purposes.

6. How Will the Proposed Rule Affect the Method of Determination Codes?

Background. Two method of determination codes, MODC values ''13'' and ''15'' from Table 4a under § 75.57, became inactive as of January 1, 2000. Also, today's proposed rule would add provisions that require new MODCs that do not appear in the current version of Table 4a.

Discussion of Proposed Changes. EPA proposes to add three new MODC codes, ''21,'' ''22,'' and ''23'' to Table 4a in § 75.57 for use in the electronic data reporting (EDR) format, and to designate the inactive codes ''13'' and ''15'' as ''Reserved.'' MODC 21 would be used when replacing a negative hourly concentration, emission rate, or percent moisture value with zero. MODC 22 would be used when an hourly average

SO_2 or NO_X concentration is reported from a certified monitor at the inlet to an emission control device. MODC 23 would be used when the maximum potential SO_2 concentration, CO_2 concentration, NO_X concentration, NO_X emission rate, or flow rate, or when the minimum potential moisture percentage is reported for an hour in which flue gases are discharged through an unmonitored bypass stack. These changes will make the specific electronic data reporting format elements consistent with the rule.

D. Low Mass Emissions (LME) Units

1. What Are the Certification Requirements for Low Mass Emissions (LME) Units?

Background. In response to concerns raised by both regulated entities and other regulatory agencies, EPA examined the administrative procedures pertaining to LME units in part 75. It was determined that some provisions should be clarified to simplify program implementation and insure that the LME requirements are consistent with other sections of part 75.

Discussion of Proposed Changes. The proposed revisions require the electronic portion of the LME certification application to be sent to EPA Headquarters (the Clean Air Markets Division) and the hardcopy portion to the appropriate Region and State. The proposal would also require LME applications to be submitted no less than 45 days prior to the date on which use of the methodology will commence.

In addition, EPA proposes to remove the references to January 1, 1997, in §§ 75.19(a)(2)(ii), 75.19(b)(4), and 75.20(h)(3), as this date has no regulatory or statutory significance. Instead, the use of these provisions would depend upon whether a unit is a new or newly affected unit and to what extent the LME applicability demonstration relies on the use of projected data, instead of actual, historical data. The proposal would also clarify the period of provisional certification for LME units in § 75.20(h)(3), the date on which a qualifying unit begins using the methodology in § 75.19(a)(1)(ii), and the certification application submittal process in § 75.63(a)(1).

2. How Does the LME Methodology Apply to Subpart H Units?

Background. In its current form § 75.19 contains only a limited explanation of the requirements for units subject to subpart H of part 75 (and not covered under the Acid Rain Program) that are using the LME methodology to account for emissions. Note that some of these requirements for subpart H units are the same as those for Acid Rain Program units.

Discussion of Proposed Changes. Paragraphs (a), (b), and (c) of § 75.19 would be revised to distinguish the applicability, on-going qualification, and reporting requirements for Acid Rain Program units and non-Acid Rain Program, subpart H units. The revisions would make a clear distinction between sources that report emission data on a year-round basis and those that report data only during the ozone season. These changes would help owners and operators of non-Acid Rain Program units understand how to comply with the LME requirements. Language was added to clarify that non-Acid Rain Program units using the LME methodology and the provisions of subpart H of part 75 (to comply with the monitoring and reporting requirements of a NO_X mass trading program) must submit NO_X mass emission data, but are not required to submit SO_2 mass emissions data. In addition, language was added to clearly state the initial and ongoing qualification criteria for non-Acid Rain Program units. Specifically, non-Acid Rain Program units for which you choose to report data year round under the LME methodology must emit no more than 50 tons of NO_X annually, while units for which you choose to report only ozone season NO_X mass emission data must emit no more than 25 tons of NO_X each ozone season.

3. When Must the Annual Demonstration for LME Units be Completed?

Background. The current rule does not specifically state the deadline for performing the annual demonstration of LME qualification. EPA believes that a consistent standard should be used for all units every year.

Discussion of Proposed Changes. For a unit to continue to qualify as a LME unit, certain mass emission thresholds must be met on an on-going basis. These thresholds are: 25 tons SO_2 and 50 tons NO_X annually for an Acid Rain Program unit; 50 tons NO_X annually for a non-Acid Rain Program, subpart H unit reporting on a year-round basis; and 25 tons per ozone season for a non-Acid Rain Program, subpart H unit reporting on an ozone season basis only. The owner or operator must demonstrate annually that the unit does not exceed the applicable mass emissions threshold(s). The proposed rule would add language to § 75.19(b)(1) to expressly state that the annual demonstration will be considered complete only when the official data reconciliation process is complete. More specifically, only the final emissions data record for the year or ozone season (i.e., the final accounting of emissions, after data have been fully reconciled and any necessary quarterly report resubmittals have been made) will be used to determine whether a unit has met the applicable mass emissions threshold and satisfied the LME qualification requirements.

4. How Should EPA Reference Method 20 Be Altered When Determining a Fuel-and Unit-Specific NO_X Emission Rate for an LME Unit?

Background. The Method 20 test procedures require the measured NO_X concentrations to be corrected to 15 percent O2. For units simply determining the NO_X emission rate, this correction is unnecessary because the measured fuel- and unit-specific NO_X emission rate will be the same whether or not the concentration is corrected to 15 percent O2.

Discussion of Proposed Changes. Today's proposal would remove the requirement from § 75.19(c)(1)(iv)(A) that a unit must correct NO_X concentration values to 15 percent O2 when performing Method 20 testing.

5. What Temperature and Humidity Corrections are Required for Turbines When Unit- and Fuel-Specific NO_X Emission Rates are Determined for LME Units?

Background. Beginning in the 1999 ozone season, the Ozone Transport Commission (OTC) NO_X Budget Program required monitoring and reporting of NO_X mass emissions for use in a regional NO_X trading program. Each State participating in the program required monitoring and reporting to be performed according to the ''Guidance for Implementation of Emissions Monitoring Requirements for the NO_X Budget Program'' and the '' NO_X Budget Program Monitoring Certification and Reporting Instructions.'' These documents required reporting of emissions data in the Electronic Data Reporting (EDR) version 2.0 format. Under this program, a large number of small peaking turbines were required to begin monitoring and reporting data in the EDR v2.0 format. This group of units contains simple combustion peaking turbines of 15 to approximately 75 MWh capacity. These units have historically been exempt from the Acid Rain Program monitoring and reporting under either § 72.6(b)(1), an exemption for simple turbines built prior to November 15, 1990, or § 72.7, the new unit exemption. The monitoring and reporting options allowed for these type of units in the OTC NO_X Budget Program guidance documents are similar to the monitoring and reporting provisions under § 75.19 with some key differences, including the use of a multiplier of 1.15 to all fuel- and unit-specific NO_X emission rates determined using the testing procedures of appendix E. In the preamble to the May 1999 final revisions to part 75, EPA states that the reason for the 1.15 multiplier is that the NO_X emission rate may vary at a given load for any particular unit. In particular, EPA was concerned with possible underestimation of emissions using the results of appendix E testing to determine fuel- and unit-specific NO_X emission rates.

EPA anticipates that the majority of the simple peaking turbine units described above will be required to begin monitoring and reporting data according to the LME provisions under § 75.19 in the future as part of a larger NO_X trading program. Several utilities asked that the LME requirements under § 75.19 be modified to allow removal of the 1.15 multiplier to fuel and unit-specific NO_X emission rates. They argued that the requirement to use a 1.15 multiplier would result in a high overestimation of NO_X emission rates under some circumstances. EPA investigated the causes of variability in NO_X emission rates in turbines by reviewing literature, reviewing test results, analyzing CEMS data for turbines, and by discussing turbine operation with turbine and utility experts (*see* Docket A–2000–33, Item II–B–1). The result of the investigation was confirmation that temperature, pressure, and, in particular, humidity affect the NO_X emission rate in combustion turbines. The investigation revealed that several empirically-derived mathematical algorithms have been developed to correct a measured NO_X concentration to a theoretical NO_X concentration at a different temperature, pressure, and humidity, including the equation in subpart GG, Standards of Performance for Stationary Gas Turbines (§ 60.335).

Discussion of Proposed Changes. The proposal would add a new requirement for certain turbines to correct measured NO_X concentrations using an equation similar to the equation in subpart GG of the New Source Performance Standards (40 CFR part 60), for correcting to the International Organization for Standardization (ISO) standard ambient conditions. This correction, in § 75.19(c)(1)(iv)(A)(4), would apply only to uncontrolled diffusion flame style turbines and would compensate for temperature and humidity effects on NO_X formation by correcting the measured NO_X concentrations at the test conditions to the average annual temperature, atmospheric pressure, and humidity at the location of the turbine. If a unit (including an Acid Rain Program unit) is subject to an ozone season-based NO_X mass emission reduction program, average ozone season values of temperature, atmospheric pressure, and humidity would be used instead of average annual values. The proposed rule suggests (but does not require) using National Oceanic and Atmospheric Administration temperature and humidity data from the weather station at the nearest airport. This provision would prevent underestimation or overestimation of NO_X emissions for uncontrolled diffusion flame turbines. Today's proposal also removes the requirement to multiply the measured NO_X emission rates for such turbines by 1.15, as the new correction equation would make use of the multiplier unnecessary.

6. How Is Identical Unit Status Demonstrated for a Group of LME Units?

Background. The rule currently requires, in § 75.19(c)(1)(iv)(B)(1), that to be considered identical a group of LME units must be of the same manufacturer, model, and size, have the same history of modifications (e.g., the same controls installed), and have similar outlet temperatures under similar operating conditions. Section 75.19(c)(1)(iv)(B)(3) further requires that if there are more than two identical units in the group, the NO_X emission rate of each unit tested must be within 10 percent of the average emission rate for all units tested, at each load level.

Discussion of Proposed Changes. The proposal would delete from § 75.19(c)(1)(iv)(B)(3) the requirement that the emission rate for each unit must be within 10 percent of the group average rate in order for a particular unit to be considered an identical unit. These proposed identical unit provisions in part 75 are based in large part on comparable provisions used under the Ozone Transport Commission (OTC) NO_X Budget Program. Because the OTC requirements for identical units have been effective and have minimized the compliance burdens on LME units, EPA believes that it is appropriate to eliminate the ten percent requirement from the part 75 LME provisions. The criteria in § 75.19(c)(1)(iv)(B)(1) for identifying identical units would be retained, however.

7. How Is the Fuel- and Unit-Specific NO_X Emission Rate Determined for LME Turbines Equipped With Water Injection, Steam Injection, or Water/Fuel Emulsion, and no Other Type(s) of add-on NO_X Controls?

Background. The current LME provisions in § 75.19 include a provision which restricts the use of fuel- and unit-specific NO_X emission rates to be no less than 0.15 lb/mmBtu for units with any type of NO_X emission controls. Use of the 0.15 value ensures that large, highly controlled units would not use the LME provisions for estimating emissions. EPA believes that the LME provisions are inappropriate for units with such controls as SCR or SNCR and that NO_X emission monitoring is the only effective way to determine that a unit achieves its target control level. Industry representatives have asked EPA to consider allowing the use of controlled fuel and unit specific NO_X emission rates below the 0.15 lb/mmBtu minimum for turbines with water injection, steam injection, or water/fuel emulsion. The representatives stated that if the water-to-fuel ratio were monitored each hour, the use of a fuel- and unit-specific default for times when the water-to-fuel ratio were within acceptable limits would not underestimate emissions.

EPA investigated the claims of the industry representatives. EPA reviewed data from CEMS installed at turbines with water and steam injection and water/fuel emulsion. Based on results of the investigation, EPA believes that if the water-to-fuel ratio is monitored, then effective and constant control of NO_X is achieved with little chance of underestimation of NO_X emissions (see Docket A–2000–33, Item II–B–1).

Discussion of Proposed Changes. The proposal would revise § 75.19(c)(1)(iv)(H)(1) to allow the use of measured NO_X emission rates for units with water or steam injection or water/fuel emulsion (and no other type(s) of add-on NO_X controls) even if the emission rates are below 0.15 lb/mmBtu. This removes the current rule requirement that all tested emission rates below 0.15 lb/mmBtu be adjusted upward to a default value of 0.15 lb/mmBtu. The proposed action requires units with steam or water injection to monitor the water-to-fuel or steam-to-fuel ratio in order to give assurance that the emission controls are operating properly, making it unnecessary to use the default value.

8. What Effect Would Today's Proposed Rule Have on LME Units Sharing a Common Fuel Supply?

Background. The current LME provisions require that where a group of units shares a common fuel supply, use the long term fuel flow (LTFF) methodology for heat input, and use a fuel-and unit-specific default NO_X emission rate, the group of units must perform the required testing and use the highest tested NO_X emission rate for all units. EPA has reviewed the requirement for taking the highest NO_X emission rate for all units, found it to be unnecessary, and is proposing to remove the requirement.

Discussion of Proposed Changes. Today's proposal would delete and reserve §§ 75.19(c)(1)(iv)(C)(2) and 75.19(c)(1)(iv)(C)(5). These sections describe unnecessary restrictions for groups of units sharing a common fuel supply and using the long term fuel flow heat input approach. It is highly unlikely that an incorrectly apportioned heat input for units with different efficiencies could lead to improper estimation of emissions. Therefore, EPA proposes to remove these restrictions from the rule. In addition, a source would use the highest rate at each individual unit to calculate emissions from that unit, rather than using the highest NO_X emission rate from the entire group of units.

9. When Would Single Load Testing Be Allowed to Determine Unit- and Fuel-Specific NO_X Emission Rates for LME Units?

Background. The current LME provisions require four load testing for all units which opt to determine a default fuel- and unit-specific NO_X emission rate. Several industry representatives asked that this requirement be waived for units which operate at a single load only. EPA considered two options as alternatives to the four load testing requirement.

Option 1. Require the first appendix E test to be performed at all four loads, then allow future testing to be performed at the load at which the highest NO_X emission rate was found.

Option 2. Allow single load testing for units which submit a demonstration that a unit operates at a single load.

EPA considers option 2 to be preferable. It allows single load testing to be performed as of the first test and can save time and effort, consistent with the intent of the LME provisions to be cost effective and simple to use. EPA solicits comment on these methods or other methods suitable for allowing single load testing to be used for determining fuel- and unit-specific NO_X emission rates.

Discussion of Proposed Changes. EPA proposes to add a new provision to the rule, § 75.19(c)(1)(iv)(I), which would conditionally allow single load testing for a unit which the owner or operator can demonstrate has operated at a single load level for at least 85 percent of the time in the three years prior to the emission test. In addition, the new section would conditionally allow turbines, that operate to a set point temperature and not a given load, to perform single load testing. If a set point turbine is tested at base load, but the unit is capable of operating at a higher (peak) load and is not tested at peak load, the fuel- and unit-specific NO_X emission rate obtained from the base load testing would be adjusted upward using a conservative multiplier of 1.15 to ensure that emissions are not underestimated when the unit operates at peak load.

10. How Are Unit-Specific, Fuel-Specific NO_X Emission Rates for LME Units Determined From the Individual Test Run Data at Each Load Level?

Background. The current LME provisions require the use of the highest emission rate from the appendix E test. This language is not clear in describing whether the value used was the highest reading of any run during the test or the average of the required three runs during the test. In this rulemaking EPA is clarifying its intent that the three run average from a test is the value used as the fuel- and unit-specific default emission rate.

Discussion of Proposed Changes. Today's proposal would revise § 75.19(c)(1)(iv)(C) to clarify the way in which the fuel- and unit-specific NO_X emission rates are calculated for LME units when four load emission tests are performed. The proposal would add new language to that section, explaining how to determine the appropriate NO_X emission rates when single load testing is performed.

For four load testing of an individual LME unit, the appropriate NO_X emission rate would be the highest three-run average obtained at any load level tested. For single load testing, the NO_X emission rate would simply be the three-run average at the load level tested. For four load testing of a group of identical LME units, the appropriate NO_X emission rate would be the highest three-run average obtained for any unit in the group, at any load level tested. For single load testing of a group of identical LME units, the NO_X emission rate would be the highest three-run average obtained for any tested unit.

11. Which Mathematical Equations Are Affected by the Proposed Changes to § 75.19?

Background. Today's proposal would correct several equations pertaining to LME units. These revisions are necessary to correct one equation and to clarify the nomenclature of several other equations.

Discussion of Proposed Changes. The proposed revisions will correct Equation LM–1 and clarify the nomenclature for Equations LM–3, LM–5, LM–6, LM–7, LM–7a, LM–8, and LM–8a.

E. Conditionally Valid Data—Mandatory Use

Background. In the May 26, 1999, revisions to part 75, new CEM data validation provisions were promulgated. One such provision in § 75.20(b)(3) addresses the use of conditional data validation. For recertification testing and diagnostic tests, § 75.20(b)(3) requires that sources use conditional data validation. For initial certifications and routine quality assurance, the rule allows, but does not require, conditional data validation.

Discussion of Proposed Changes. To address the inconsistency in the rule, § 75.20(b)(3) would be revised to make the use of conditional data validation optional in all cases. Appendix A, sections 2.1.1.5(c) and 2.1.2.5(c) and appendix B, sections 2.2.5, would also be revised to reference the amended § 75.20(b)(3).

F. Quality Assurance/Quality Control (QA/QC)

1. What Changes Are Proposed for CEMS Span and Range Evaluations?

Background. Part 75 requires periodic evaluations (at least annually) of the spans and ranges of all required continuous monitors to ensure that the proper span and range values are being used. To perform the annual span/range evaluation, a review of the emission data from the past year is required. The results are acceptable if the data meet the guidelines in section 2.1 of appendix A. The basic requirement of that section is for the majority of the data to be between 20 and 80 percent of the full-scale range, with certain allowable exceptions.

With the increased emphasis in recent years on reducing NO_X emissions, many new combustion turbines are being built. The span/range evaluation guideline in section 2.1 of appendix A does not fully address the issues raised by this type of unit. These units typically have NO_X controls capable of reducing emissions to very low levels (e.g., 20 ppm or less for oil-firing and less than 10 ppm for gas-firing) and are often required by part 75 to have two measurement ranges (low and high). Some of these units operate their emission controls only on a seasonal basis, rather than year-round. One span and range issue for these units is that when natural gas is combusted, the majority of the NO_X emissions may not meet the 20 to 80 percent guideline of section 2.1 if, for example, the low-scale measurement range is set at 25 ppm based on oil-firing, in accordance with section 2.1.2.3 of appendix A. Further, if gas is the primary fuel in this example and the NO_X emissions are typically 5 ppm or less during gas combustion, one might erroneously conclude during the annual span/range evaluation that the low range needs to be adjusted or that a third monitoring range (e.g., 0–10 ppm) is necessary to measure the gas-fired emissions, in order to meet the section 2.1 guideline. A second issue is that under appendix A, section 2.1, for dual-span units with add-on emission controls, SO2 or NO_X data recorded on the high monitor range are exempted from meeting the 20 to 80 percent guideline. However, this exemption is not appropriate for units with seasonally operated emission controls.

Discussion of Proposed Changes. To address the first issue described above, the proposed rule would clearly state that for dual-span units low-range readings below 20 percent of full-scale are exempted from the 20 to 80 percent guideline, provided that the maximum expected concentration (MEC) and the low-scale span and range values have been determined according to the applicable provisions of appendix A. In the example cited in the Background section above, if the low measurement range of 25 ppm (based on oil-burning) was properly set according to section 2.1.2.3 of appendix A, then re-ranging the low measurement scale would not be appropriate, even if the majority of the data do not fall between 20 and 80 percent of the range when natural gas is combusted. This is because the unit is capable of burning oil, and a low-scale range of 25 ppm, if set according to section 2.1.2.3 of appendix A, is a good choice for that fuel. Nor would it be necessary to establish a third monitoring range. Part 75 was never intended to require more than two monitoring ranges.

To address the second issue described above, the proposed rule would require units that operate their emission controls seasonally to meet the 20 to 80 percent guideline on the high measurement range. The Agency believes it is appropriate for units using their emission controls seasonally (such as a unit that uses SCR during the summer only) to meet the 20 to 80 percent guideline on the high range because emissions data will be recorded on that range for extended periods of time during the year. This is unlike the case in which controls are used year-round, where the source is likely to operate without the controls only on occasion and relatively few readings are recorded on the high scale.

2. Will EPA Allow Use of Two Separate CEM Systems With Separate Probes and Sample Interfaces To Meet Dual-Range Requirements?

Background. For units required to have two spans and ranges for NO_X or SO2, the current rule disallows the use of two separate CEM systems with separate probes and sample interfaces. This option was excluded because dual-span units often use add-on controls and have very low emissions. In many cases, the add-on controls are used year-round, so the emissions remain low virtually all the time. The low emission levels can make it difficult to perform and pass a RATA on the high range. Despite this, EPA has received two petitions requesting permission to use separate systems with separate probes and interfaces to meet a dual-range requirement (*see* Docket A–2000–33; Items II–C–1 and II–D–13). To date, one of these petitions has been approved, for a unit that operates its NO_X controls seasonally.

Discussion of Proposed Changes. Today's proposal would revise appendix A, section 2.1 to conditionally allow the use of separate CEMS with separate probes and interfaces to satisfy dual-range requirements. The condition is that RATAs of both ranges must be performed and passed. The revised rule would also state that the two CEMS should be designated as separate monitoring systems in the monitoring plan.

3. What Changes Would the Proposed Rule Make With Regard to Determining NO_X MPC, MEC, Span, and Range?

Background. EPA receives many questions about the way in which the MPC, MEC, span, and range are determined for NO_X, especially for new combustion turbines. Some of the questioners have requested additional options for MPC and MEC determinations and claim that the rule does not address dry, low-NO_X control technology, which is being used on many new turbines. Others have questioned the appropriateness of the 50 ppm default value for the MPC of new turbines in Table 2–2 of appendix A.

Discussion of Proposed Changes. The proposed rule would clarify the definition of MPC for NO_X, making a distinction between uncontrolled units and units with low NO_X burner technology. The proposal would also revise appendix A, section 2.1 to add a new option for NO_X MPC determination: use of a reliable estimate of the unit's uncontrolled emissions obtained from the manufacturer. A new option for MEC would also be added: use of the federally-enforceable permit limit. The new MEC option could only be used for units that have add-on emission controls or that use dry, low-NO_X technology.

The 50 ppm default MPC value for new turbines in Table 2–2 would be removed and replaced with two new values: (a) 150 ppm for units that are permitted to fire only natural gas; and (b) 200 ppm for units permitted to fire both gas and oil. These values are much more representative of actual NO_X emissions from turbines during unit startup and periods when the emission controls are not operational. EPA requests comment on whether the new values are representative (*see* Docket A–2000–33, Item II–B–2).

Finally, default MPC values would be added to the rule for two categories of non-load-based units: cement kilns and process heaters. As discussed in more detail under section III.C of this preamble, certain States are likely to require these two source categories to report NO_X mass emissions under the NO_X SIP call. For cement kilns, an MPC value of 2,000 ppm is proposed; for process heaters, an MPC value of 200 ppm is proposed for gas-fired units, and 500 ppm for oil-fired heaters. The default MPC value for cement kilns was determined using NO_X emissions data sent to EPA during pre-proposal discussions between the Agency, representatives of cement kilns located in New York, and the Portland Cement Association. NO_X emissions data for seven cement kilns were submitted for review. The data represented more than one year of hourly NO_X concentration values for each of the kilns. EPA selected 2,000 ppm as an appropriate MPC for cement kilns based on the maximum values reported for these units (*see* Docket A–2000–33, Item II–I–3). For process heaters, the Agency evaluated NO_X emissions data submitted in quarterly EDR reports for six process heater units regulated under the OTC NO_X Budget Program. EPA selected the 200 and 500 ppm MPC values based on the maximum NO_X concentration values reported for these units (*see* Docket A–2000–33, Item II–I–3). EPA is proposing the default NO_X

MPC values for cement kilns and process heaters principally because an MPC value would be required in the initial monitoring plan submittal if these units were to become regulated under the NO_X SIP call. None of the default NO_X MPC values in appendix A, section 2.1.2.1 of the current rule are considered to be appropriate for either cement kilns or process heaters, and emission test results or historical CEMS data might not be available at the time of initial monitoring plan submittals from these sources. Therefore, EPA has proposed default NO_X MPC values that can be used for the initial MPC determinations for cement kilns and process heaters.

4. What Revisions Would Be Made to the 7-day Calibration Error Test for Peaking Units?

Background. For gas monitors, the 7-day calibration error test is required only for initial certification, recertification, and occasionally as a diagnostic test. It is not a routine, required periodic QA test. The current rule specifies that the 7-day calibration error test data must be recorded while the unit is operating. For peaking units, the requirement for the unit to be operating during the test can be problematic. Because of the infrequent and unpredictable nature of peaking unit operation, the 7-day test may take weeks or even months to complete.

Discussion of Proposed Changes. Today's proposal would revise the 7-day calibration error test requirement for gas monitors installed on peaking units in appendix A, section 6.3.1, to require data to be recorded for only three of the seven test days with the unit operating. The unit would not be required to operate for the other four days of the test.

5. What Changes Would Be Made to QA/QC for Units With Very low NO_X Concentrations?

Background. The current rule requires owners and operators of units with very low SO2 and NO_X concentrations to perform RATAs and daily calibrations on their CEMS. They are required to perform linearity checks unless the span value is 30 ppm or less (see appendix A, section 6.2). Appendix B to part 75 provides an alternate daily calibration specification for low emitters of SO_2 and NO_X.

With respect to the daily calibrations of SO_2 and NO_X monitors, the allowable calibration error is currently 5 percent of the span value. However, appendix B to part 75 provides an alternate daily calibration specification for low emitters of SO_2 and NO_X. The alternative specification for units with low concentrations (for span values less than 200 ppm) is 10 ppm or less (based on the absolute value of the difference between the tag value of the calibration gas and the instrument response). For most low-emitting sources, the alternate 10 ppm specification is reasonable and provides relief from the 5 percent of span requirement, which is often too stringent at low span values. However, for very low span values, the 10 ppm alternate specification is not stringent enough and needs to be tightened. This is especially important because many of the new Acid Rain-affected gas turbines that are being built have very low NO_X emissions. To illustrate, suppose that for a very low span value of 10 ppm, the upscale calibration gas for daily calibrations is 9 ppm. When the 10 ppm alternate calibration error specification is applied, the monitor could actually be inoperative, read 0 ppm, and the calibration would still be passed.

Discussion of Proposed Changes. Today's proposal would modify the alternate calibration error specification in section 2.1.4(a) of appendix B, for daily operation of SO_2 and NO_X monitors. The 10 ppm alternate specification would be retained for span values greater than 50 ppm but less than 200 ppm. For span values less than or equal to 50 ppm, the alternate specification would be lowered to 5 ppm. EPA believes that a daily calibration error limit of 5 ppm is both reasonable and achievable, in view of the measurement capability of today's gas analyzers. The Agency notes that 5 ppm is also the alternate low-emitter performance specification in section 3.1(b) of appendix A, for initial certification of SO_2 and NO_X monitors.

6. When Would EPA Require the Application of a Calibration Correction Factor to Linearity or RATA Test Data?

Background. After a routine daily calibration error test, many Data Acquisition and Handling Systems (DAHSs) apply a mathematical correction to the subsequent emission data in order to account for the calibration error. When a linearity check or RATA is initiated after a daily calibration, the current rule does not specify whether the mathematical correction factor should be applied to the monitor readings recorded during the linearity test or RATA.

Discussion of Proposed Changes. EPA proposes to add language to sections 2.2.3(c) and 2.3.2(c) of appendix B, requiring that if a mathematical correction factor (calibration adjustment) is applied by the DAHS following a daily calibration error test, the correction factor would be applied to all subsequent data recorded by the monitor until the next calibration error test is performed, including any linearity test or RATA data recorded in that time interval.

7. What Changes Would Be Made to the Flow-to-Load Ratio Test?

Background. In the May 26, 1999, revisions to part 75, a new quarterly QA test for flow monitors was promulgated: the flow-to-load ratio test. Since promulgation, EPA has received many questions about the methodology, relating both to the procedural aspects of how the data analysis is done and to the consequences when the test is failed. As a result, EPA believes it is necessary to clarify the test procedures and to re-evaluate the issue of data validation when the test is failed.

Discussion of Proposed Changes. The proposed rule would allow you to take the data exclusions listed in section 2.2.5(c) of appendix B before analyzing the quarterly flow-to-load data. The current rule appears to require an initial data analysis with no exclusions and to allow owners and operators to claim the data exclusions only when the first analysis results in a failed test. Proposed section 2.2.5(c) also clarifies the issue of co-firing as it pertains to data exclusions. For units that co-fire different fuels as part of their normal operation, you could claim flow-to-load test data exclusions for hours in which fuels were not co-fired if the reference flow RATA at normal load was done while co-firing. Conversely, if the reference flow RATA was done while firing a single fuel, flow-to-load test data exclusions could be claimed for hours in which fuels were co-fired. The proposed rule would also add a statement to section 6.5(a) of appendix A requiring that units which co-fire fuels as the predominant mode of operation perform RATAs while co-firing.

The proposal would change the method of data validation following a flow-to-load ratio test failure. Section 2.2.5(c)(8) of appendix B would allow the flow rate data to be declared conditionally valid, rather than invalid, when a flow-to-load test is failed, pending the results of a follow-up investigation and/or a RATA. This would allow data validation in case a false positive is obtained with the flow-to-load test. If the investigation fails to reveal a problem and a confirming RATA is passed hands-off, no data loss would be incurred. The timeline for investigating a flow-to-load test failure would also be changed from ‘‘within 2 weeks'' to ''within 14 unit operating days.''

The proposal would clarify the instructions for multiple stack configurations and allow you to do the data analysis in one of two ways: (1) Using combined flow and average unit load; or (2) using the flow in each stack and the corresponding unit load.

Finally, section 7.8 in appendix A of part 75 would be revised to exempt non-load-based units (i.e., units that do not produce electrical output or steam load) from the flow-to-load ratio test.

8. When Would Three-Load Flow RATAs Be Allowed for Routine Quality Assurance?

Background. The current rule specifies that an annual two-load flow RATA is required for routine quality assurance of a flow monitor. The rule appears to require two-load testing and to disallow three-load tests for routine QA.

Discussion of Proposed Changes. Today's proposal would clarify in section 2.3.1.3(c) of appendix B that you may perform a three-load RATA in lieu of any required two-load flow RATA.

9. What Changes Would Be Made to the Data Analysis Time Period for Single-Load Flow RATA Claims?

Background. In the May 26, 1999 revisions to part 75, a new provision was promulgated, allowing annual flow RATAs to be done at a single load level. To qualify for the single-load option the source must have operated at one load level (low, mid, or high) for at least 85% of the time since the last annual flow RATA. A historical load analysis must be done to confirm this, extending from the date and hour of completion of the last annual flow RATA to a date no less than seven days prior to the date of the current annual flow RATA. Some utilities have asked if EPA would consider changing this timeline. Two suggestions have been offered: (1) Make the end date of the analysis 21 days ahead of the scheduled RATA date; and (2) include in the analysis all data from the quarter of the last RATA and exclude all data from the quarter of the current RATA.

Discussion of Proposed Changes. EPA believes that the suggested revisions are appropriate and would increase the amount of time available to conduct test planning. The proposal would modify the timeline for the data analysis in section 2.3.1.3(c) of appendix B, to allow data to be analyzed from either: (a) The date/hour of the last annual flow RATA to a date no more than 21 days prior to the current flow RATA; or (b) the beginning of the quarter in which the last annual flow RATA was done, through the end of the calendar quarter preceding the quarter of this year's annual flow RATA.

10. For Units That Do Not Produce Electrical Output or Steam Load, at What Operating Levels Should Gas and Flow Monitor RATAs Be Performed?

Background. For units that do not produce electrical or thermal output (e.g., cement kilns and process heaters), today's proposed rule would provide a method by which to establish the proper ''operating levels'' (as opposed to ''load levels'') at which to perform relative accuracy test audits (RATAs). The proposed methodology is found in section 6.5.2.1 of appendix A. The rationale for, and a discussion of, these proposed rule provisions is presented in the following paragraphs.

Units subject to the monitoring and reporting requirements of part 75 must account for their emissions on a continuous basis. Most units use continuous emission monitoring systems (CEMS) for this purpose. Part 75 requires periodic RATAs of all CEMS to demonstrate that the data recorded by the monitoring systems accurately represent the SO_2, NO_X, and CO_2 emissions from the affected unit. RATAs of gas and flow monitors are required for initial certification and either semiannually or (if the relative accuracy obtained on the previous RATA was ≤ 7.5 percent) annually thereafter.

Section 6.5.1 of appendix A to part 75 requires that RATAs of gas monitors be done at the ''normal'' load level. Section 6.5.2 of appendix A and section 2.3.1.3 of appendix B specify the load levels for flow RATAs. In general, flow monitor RATAs are performed at multiple load levels (either two or three), with a few exceptions (e.g., for flow monitors installed on peaking units, only single-load RATAs are required). For multiple-load flow RATAs, at least one of the tested load levels must be the ''normal'' load level.

The method of establishing the normal load level is found in section 6.5.2.1 of appendix A. First, the owner or operator must determine the ''range of operation'' for the unit or stack. The range of operation extends from the minimum safe, stable load to the maximum sustainable load. Next, the range of operation is divided into three load levels. The first 30 percent of the range of operation is considered to be the ''low'' load level, the next 30 percent of the range is the ''mid'' load level, and the remaining 40 percent of the range is the ''high'' load level. The ''normal'' load level is determined by performing an analysis of at least four quarters of representative historical load data. From these data a distribution graph, such as a histogram, is constructed showing the percentage of the time that each load level has been used historically. The most frequently-used load level (low, mid, or high) is automatically designated as the normal load level. The owner or operator may opt to designate the next most frequently used load level as a second normal load. Thus, the appropriate load levels for the required RATAs of the gas and flow monitors are established.

Discussion of Proposed Changes. As previously discussed in section III.C of this preamble, EPA anticipates that under the NO_X SIP call, sources such as cement kilns or refinery process heaters, which do not produce electrical or thermal output, will become subject to the monitoring and reporting requirements of part 75. Consequently, these sources will be required to perform periodic RATAs of their gas and flow monitors. Because these sources do not produce electrical or steam load, the concept of performing ''normal load'' RATAs cannot be applied to them. Therefore, an alternative RATA approach is needed for these non-load-based units. Today's proposed rule would revise section 6.5.2.1 of appendix A to provide the necessary alternative methodology.

The proposed RATA approach for units that do not produce electrical or steam load would be based on an ''operating level'' concept, rather than a ''load level'' concept. The method of determining the normal operating level for a non-load-based unit would be much the same as the previously-described method for determining the normal load level for a load-based unit. The owner or operator would determine the range of operation, divide it into three operating levels, and perform a data analysis to establish the ''normal'' (i.e., most frequently-used) operating level. The only significant difference between the load-based and non-load-based methodologies is that instead of defining the range of operation in units of electrical or steam load (i.e., in megawatts or klb/hr of steam), the range of operation of the non-load-based unit would be defined in units of stack gas velocity, in ft/sec. The range of operation would extend from the minimum expected velocity to the maximum potential velocity. These minimum and maximum gas velocities could either be determined from reference method test data or by using Equation A–3a or A–3b (as applicable) in section 2.1.4.1 of appendix A to part 75.

EPA is aware that for new or newly-affected units, four quarters of historical load data (for load-based units) or flow rate data (for non-load-based units) may not be initially available to establish the two most frequently-used operating loads (or levels) and the normal operating load (or level). Also, for a non-load-based unit which is not required to install a flow monitor, the necessary flow rate data for the determinations will neither be available initially nor at some point in the future. Therefore, a revision to section 6.5.2.1 (c) of appendix A is proposed, which would allow the initial determinations to be made as follows: (1) For load-based units or for non-load-based units with installed flow monitors, the determinations could be based on less than four quarters of data, or, if no representative historical data are available, projections of how the unit will be operated could be used. Note, however, that as soon as four representative quarters of load or flow rate data are obtained, the determination of the two most frequently-used operating loads (or levels) and the normal operating load(s) (or level(s)) would have to be repeated; or (2) for non-load-based units without installed flow monitors, sound engineering judgment (based on a combination of knowledge of the unit, operating experience, and actual stack gas velocity measurements using EPA Method 2) would be used to make the operating level determinations.

Once the boundaries of the range of operation are established and the normal operating level(s) has been identified, the owner or operator of a non-load-based unit would perform the required gas and flow RATAs in essentially the same manner as for a load-based unit. The only difference is that in many sections of part 75 the term ''operating level'' would replace the term ''load'' or ''load level.'' Today's proposed rule would modify the text in several sections of part 75 (e.g., by adding a parenthetical expression such as ''(or normal operating level)'' after the term ''normal load''), to indicate that the provisions apply to both load-based and non-load-based units. The affected rule sections are: § 75.20(c)(2), sections 6.5.1, 6.5.2, 6.5.6.1(a), and 6.5.6.2(a) of appendix A, and sections 2.3.1.3, 2.3.2(d), 2.3.2(f), 2.4(b), and Figure 1 of appendix B.

G. Streamlining Changes

Background. There are a number of rule sections in part 75 that have expired, either on December 31, 1999, or on March 31, 2000. For some, but not all, of these expired rule provisions, part 75 contains new (replacement) provisions, having effective dates of January 1, 2000, or April 1, 2000, respectively. The expired provisions are a potential source of confusion to both the regulated community and to regulators in assessing compliance with part 75. For instance, the rule contains two sets of recordkeeping and reporting provisions, one of which expired on March 31, 2000, and the other which became effective on April 1, 2000. Removing the expired sections would greatly facilitate part 75 implementation and compliance.

EPA notes that the removal of expired provisions will not change the fact that those provisions were in effect up to their respective expiration dates. EPA intends to take appropriate enforcement action against violations of those provisions that occurred before the time of expiration.

Discussion of Proposed Changes. Today's proposed changes would streamline part 75 by eliminating outdated language in the rule and by removing a number of references throughout part 75 to sections of the rule that are no longer effective. This streamlining would occur in several places in the rule.

The May 26, 1999 revisions to part 75 became effective on June 25, 1999. However, the regulatory language in certain sections of the rule specified that compliance with those sections would not be required until a later date, April 1, 2000. The reason for the later effective date of certain provisions was to allow adequate time for development of the necessary reporting software associated with the rule changes. For instance, on May 26, 1999, revised recordkeeping and reporting sections were added to the rule as new §§ 75.57, 75.58, and 75.59, to replace the previous recordkeeping and reporting §§ 75.54, 75.55, and 75.56, as of April 1, 2000. However, due to the April 1, 2000 effective date of the new sections, the old sections could not be deleted from part 75, because this would have left a regulatory gap extending from June 25, 1999 (the effective date of the May 26, 1999 revisions) until April 1, 2000, during which there would have been no part 75 recordkeeping and reporting requirements in effect. So, the old sections were left in the rule and language was added to them to indicate that they were in effect only until April 1, 2000, and could no longer be used on and after that date.

Other rule sections with April 1, 2000 expiration dates and effective dates include the monitoring plan provisions (§ 75.53, paragraphs (e) and (f) replaced § 75.53, paragraphs (c) and (d) on April 1, 2000) and the CO_2 missing data provisions (§ 75.35, paragraphs (b) and (d) replaced § 75.35(c) on April 1, 2000). Today's proposal would remove from part 75 all of the rule sections that expired on April 1, 2000, and all textual references to those sections.

Rule sections that only applied to Phase I units and are now inapplicable and textual references to those sections would also be removed by today's proposal. For example, the 15 percent relative accuracy specification for flow monitors expired at the end of Phase I (on December 31, 1999) and was replaced on January 1, 2000, by the current 10 percent standard. Today's proposed rule would revise appendix A, section 3.3.4; appendix B, sections 2.3.1.2(b) and (c), and Figure 2 of appendix B, to reflect this.

EPA has prepared a technical support document (*see* Docket A–2000–33, Item II–A–2) that identifies in tabular form each of the streamlining revisions in the proposed revisions to part 75.

H. Monitoring Plan Information Submittal

1. What Changes Are Proposed in the Timeline for Monitoring Plan Updates?

Background. In several places part 75 requires the monitoring plan to be updated following a particular change or event (such as a span adjustment). For example, § 75.62(a)(2) requires submittal of updated hardcopy portions of the monitoring plan within 30 days of the event associated with a change. However, for events that require updating of the electronic monitoring plan, in many cases no similar deadline for submitting the changes is specified in part 75.

Discussion of Proposed Changes. Today's proposed rule would add parallel requirements to §§ 75.62(a)(1) and 75.73(e) for electronic monitoring plan updates. It would require the updated electronic monitoring plan to be submitted within 30 days of the event associated with a change, unless otherwise specified in part 75.

2. Is EPA Changing the Process for Electronic Submittal of Monitoring Plan Updates and Certification/ Recertification Test Results?

Background. The current rule requires that you submit the complete, up-to-date electronic monitoring plan to EPA at least 45 days prior to initial certification, with each certification or recertification application, and in each quarterly report. The rule also requires an electronic version of the test results of all monitor certifications and recertifications to be submitted to EPA.

To best handle the data, EPA has decided to develop a consistent process for transmitting and receiving the information.

Discussion of Proposed Changes. Today's proposal would add language to §§ 75.62(a)(1), 75.63(c), and 75.73(e)(1), requiring monitoring plan updates and certification or recertification data to be submitted electronically by a method specified by EPA. The Agency's goal is to develop a process by which the required electronic monitoring plan information and test data could be submitted at any time and the database would be automatically updated. Until the final goal is achieved, EPA may use short-term, interim methods, such as email, to receive the information. The language in today's proposed rule, ''* * * by a method specified by the Administrator,'' is sufficiently general to allow the use of such interim methods until the goal is reached.

I. Appendix D—Miscellaneous Issues

Background. In addition to the revisions of the definitions of pipeline natural gas and natural gas described above in section C of this preamble, EPA believes that there are a number of other changes and clarifications that would improve implementation of the excepted method allowed under appendix D to part 75.

Discussion of Proposed Changes. The proposed rule would modify section 2.1.2 of appendix D, as follows. EPA proposes to relax the restriction in section 2.1.2 which prohibits units using the provisions of subpart H of part 75 to monitor and report NO_X mass emissions (i.e., units subject to a State or federal NO_X emission reduction program) from apportioning the measured hourly heat input at a common pipe to the individual units served by the pipe. For subpart H units, revised section 2.1.2 would conditionally allow apportionment of the common pipe heat input, provided that: (1) All of the units served by the common pipe are affected units; and (2) all of the units served by the pipe have similar efficiencies (i.e., they are all boilers or all combustion turbines). Section 2.1.2 would be further revised by removing the text from subsection 2.1.2.2 which describes a petition process for obtaining permission to apportion SO_2 emissions to the individual units served by a common pipe. This petition process is considered to be superfluous, because section 2.1.2 assumes that a certified appendix D fuel flowmeter has been installed on the common pipe. For SO_2 emissions accounting purposes, it is sufficient to report the combined SO_2 emissions for the units served by the common pipe, based on fuel flow rate measurements made at the pipe. Thus, revised section 2.1.2 would simply state that if you install a fuel flowmeter on a common pipe, you should report combined SO_2 emissions from the units served by the pipe and you should apportion the common pipe heat input to the individual units using the appropriate equation from appendix F to part 75 (e.g., Equation F–21a or F–21b).

The proposed rule would revise section 2.1.4.1 of appendix D to exempt oil-fired units that use a different grade of oil only for unit startup from using a certified fuel flowmeter. This exemption parallels the existing exemption for oil-fired units that use gas fuel only for unit startup.

The proposed rule would also revise section 2.1.4.3 of appendix D to clarify the reporting requirements when emergency fuel is burned. The owner or operator would have the option during emergency fuel combustion to either: (1) Use and report maximum potential values for heat input rate, fuel sulfur content, GCV, and density; or (2) to use measured values if a certified fuel flowmeter is installed for the emergency fuel and/or if fuel sampling and analysis of the fuel is performed.

For temperature transmitter calibrations, EPA would revise section 2.1.6.1(a) of appendix D to allow fixed reference points (such as the freezing point or boiling point of water) to be used for the zero and upscale calibrations.

For a subpart H unit for which you report data only during the ozone season and for which you use an orifice, nozzle, or venturi-type appendix D fuel flowmeter to determine heat input rate, the proposal would clarify that the owner or operator still would have to use all calendar quarters in the year to determine the deadline for the next visual inspection of the primary element (see § 75.74(c)(4)). This clarification is appropriate because the 12 calendar quarter time interval for conducting these visual inspections is not dependent on the reporting schedule.

For the optional fuel flow-to-load ratio test in section 2.1.7, minor errors in the instructions for common pipe and multiple pipe configurations would be corrected. Also, for the optional fuel flow-to-load ratio test, the proposal would allow data exclusions to be taken before analyzing the data. The current rule appears to require an initial data analysis with no exclusions, and allows the data exclusions to be claimed only when the first analysis results in a failed test. This was not the original intent when EPA adopted this provision.

For units using the fuel flow-to-load ratio test to extend the fuel flowmeter accuracy test deadline, the proposal would clarify the various reasons for which owners or operators could claim a one-quarter extension of the fuel flowmeter accuracy test deadline.

Today's proposal would clarify in Tables D–4, D–5, and elsewhere in the text that owners and operators could not continue to use an assumed sulfur content or GCV value, such as a contract specification or the maximum value from the previous year, if a sampled value exceeded the assumed value. In these circumstances the sampled value would become the new assumed value.

Guidelines would be added to section 2.3.2.1.2, explaining how to apply the results of periodic sulfur and GCV samples. Owners and operators would have to begin using the new values as of the date when the sample results were received (not retroactively to the date the sample was taken).

A clarification would be added that the demonstrations of sulfur content and GCV variability described in sections 2.3.5 and 2.3.6 are options, not requirements, for units that combust other gaseous fuels (fuels that do not qualify as either pipeline natural gas or natural gas) and choose not to perform daily GCV sampling and hourly fuel sulfur content sampling, respectively. Also, these sections would be revised to make clear that, as stated in sections 2.3.1.4 and 2.3.2.4, the 720-hour demonstration methodology may be used to demonstrate that a particular fuel meets the appropriate GCV and/or sulfur content requirements to qualify as pipeline natural gas or natural gas.

The missing data requirements for the sulfur content of gaseous fuels in Table D–6 would be changed. All of the missing data values would be based on the total sulfur content of the gas. For pipeline natural gas, a missing data value of 0.002 lb/mmBtu is proposed. For natural gas, the missing data value would be an emission rate (in lb/mmBtu) calculated from Equation D–1h, using the lesser of: (a) The maximum total sulfur content specified in the fuel contract; or (b) 1.5 times the highest total sulfur value from the previous year's samples. For gaseous fuels sampled daily, the substitute data value would be 1.5 times the highest total sulfur content obtained in the previous 30 daily samples. For gaseous fuels sampled hourly, the missing data value would be the highest total sulfur content from the previous 720 hourly samples. The reason for selecting the 0.002 lb/mmBtu value for pipeline natural gas (which exceeds the lb/mmBtu equivalent of the 0.5 gr/100 scf total sulfur limit in the definition of pipeline natural gas) and for using the 1.5 multipliers is to ensure that the missing data values will be higher than the values normally used in the calculations from Table D–5.

Equations D–10 and D–11 would be removed from section 3.4.3(b). These equations are not needed because they are redundant with equations F–21a and F–21b in appendix F. A new equation, D–15a, which gives the unit heat input rate when multiple fuels are burned during the hour, would be added to section 3.5.4.

Sections 2.3.1.4(b) and 2.3.2.4(b) of appendix D would be revised to require initial and periodic sampling of pipeline natural gas and natural gas for documenting the total sulfur content of fuel. The proposed sampling frequency is semiannual and whenever ''it is reasonable to believe that the fuel composition has changed significantly.'' EPA solicits comment on the acceptability of this rather subjective ''reasonability'' criterion for determining when an additional sample is required. For compliance purposes, more precise language such as, ''Take an additional sample whenever there is any change to the contract or fuel supply to the unit, such that the latest sample is no longer representative of the fuel currently being combusted,'' may be more appropriate.

For fuels that qualify as pipeline natural gas, the 0.0006 lb/mmBtu default SO_2 emission rate would continue to be used. For natural gas, revised Equation D–1h would be used to calculate the SO_2 emission rate, based on the total sulfur content sampling results.

Two new sections, 2.3.1.4(c) and 2.3.2.4(c), would be added to appendix D, to state that if the results of periodic sampling show exceedances of the applicable total sulfur limits, the fuel would have to be reclassified.

Finally, as previously noted under section III.C.3 of this preamble, fuel flow rate missing data provisions for non-load-based units (such as cement kilns and process heaters) would be added to section 2.4 of appendix D. Guidelines for creating and using optional ''operational bins'' for determining appropriate fuel flow rate missing data values for non-load-based units would be added to appendix C of part 75, as new section 4.

J. Reporting and Recordkeeping

1. Will Certification and Recertification Test Notice Requirements Change?

Background. For initial certifications, the current rule requires at least 45 days notice before the first date of scheduled testing. For recertifications, 45 days of advance notice is required when all recertification tests are required (full recertification), but only 7 days notice is required when all of the tests are not required (partial recertification). This raises two questions: (1) Whether the notification requirements should be the same for both certifications and recertifications; and (2) how much advance notice is actually needed.

Discussion of Proposed Changes. The proposed rule changes would revise §§ 75.20 and 75.61 to make a single notification requirement of 21 days for initial certifications and for all recertifications, regardless of whether all of the tests are required. Based on the experience to date in implementing part 75, EPA believes the existing seven day notice provides too little time for State and local agency personnel and EPA personnel to schedule site visits to observe the recertification testing. Conversely, the Agency believes that 45 days notice is too far in advance, especially for recertifications. Test observation is a critical component of agency oversight of the Acid Rain Program monitoring requirements, and the 21 day test notification requirement would ensure that the agencies can successfully fulfill this responsibility.

2. Will EPA Continue to Accept Hardcopy Certification Statements?

Background. The current rule allows either electronic or hardcopy signatures and certification statements for quarterly report submittals. This creates unnecessary extra work for the EPA analysts who must document the receipt of all compliance certifications.

Discussion of Proposed Changes. Today's proposal would revise § 75.64(d) to eliminate the option to submit hardcopy compliance certifications and would, instead, require electronic submittal. Because of the electronic reporting requirements for all other quarterly report elements, all designated representatives will have the technical capability to submit electronic certifications. This rule change should therefore reduce the reporting burdens on both the regulated entities and EPA staff.

3. Will EPA Allow the Electronic Storage of Quality Assurance/Quality Control Plan Information?

Background. Section 1 of appendix B requires you to develop a quality assurance/quality control (QA/QC) program for all approved monitoring systems at a facility. The QA/QC program must include a written plan that provides detailed procedures and operations for certain activities, such as preventive maintenance and quality assurance test procedures. You must make this information and any ancillary supporting information from the monitor manufacturer (for example, maintenance manuals) available to auditors upon request. EPA has received a request from one utility to allow the QA/QC plan information to be stored electronically rather than in hardcopy.

Discussion of Proposed Changes. Today's proposal would revise appendix B, section 1, to allow QA/QC plan information to be stored electronically, provided that the information can be made available in hardcopy to inspectors or auditors upon request. Part 75 already allows electronic storage of hardcopy monitoring plan information, if the information can be furnished in hardcopy upon request during an audit (see § 75.53(e)). The proposed rule revision would use an approach for QA/QC plans that is consistent with this existing monitoring plan provision.

K. NO_X Monitoring in Multiple Stacks/Common Stacks

Background. For an exhaust configuration consisting of a main stack and a bypass stack, if the use of the bypass stack is limited by regulation or permit to emergency malfunctions of the flue gas desulfurization system, § 75.16 of the current rule allows the maximum potential SO_2 concentration to be reported during the malfunction in lieu of installing monitors on the bypass stack. For NO_X, however, the rule has no corresponding provision. Rather, it appears that monitoring of the bypass stack or monitoring of the duct(s) leading to the bypass stack are the only available options. Also, the current multiple stack and bypass stack provisions for NO_X (see §§ 75.17(c) and 75.72, paragraphs (c) and (d)) are not particularly clear or consistent.

Discussion of Proposed Changes. EPA would clarify and expand the instructions for SO_2 and NO_X monitoring in multiple and bypass stacks in §§ 75.16(c) and 75.17(c), and in § 75.72, paragraphs (c) and (d) in this proposal. EPA would also add a new provision to §§ 75.17(c) and 75.72(c), for configurations consisting of a main stack and a bypass stack, that allows the maximum potential NO_X emission rate to be reported when the bypass stack is used. Instructions would also be provided for reporting other parameters (i.e., SO_2, CO_2, flow rate, moisture, heat input rate) during hours when the bypass stack is used.

Today's proposed rule would revise the language in § 75.16(c)(3) which restricts the reporting of the maximum potential SO_2 concentration (MPC) to emergency situations in which the flue gas desulfurization (FGD) system is bypassed. Today's rule would allow the MPC to be reported in lieu of monitoring at the bypass stack, provided that the use of the bypass stack is limited to unit startups, emergency situations, and routine maintenance of the FGD system and the main stack. Instructions would also be provided for reporting other parameters (i.e., NO_X , CO_2, flow rate, moisture, heat input rate) during hours when the bypass stack is used.

L. Appendix E Issues

1. How Will the Proposed Rule Affect Appendix E Test Notifications and Submittal of Hardcopy Recertification Test Results?

Background. For routine appendix E retests and recertification testing, the rule is currently unclear regarding the test notification requirements and submittal of the hardcopy test results.

Discussion of Proposed Changes. The proposal would add a requirement to § 75.61(a)(5) to provide notice of routine appendix E retesting at least 21 days prior to the start of the testing. It would also add a requirement to § 75.61(a)(1)(ii) to provide notice of appendix E recertification testing. Finally, the proposed rule would add a requirement to §§ 75.60(b) and 75.73(d) to submit the results of routine appendix E retest results in hardcopy to the appropriate Region and State, upon request. This is exactly analogous to the requirement in §§ 75.60(b)(6) and 75.73(d)(4) to provide hardcopy RATA results.

2. Will the Frequency of Retesting of Appendix E Units Be Changed?

Background. Section 2.2 of appendix E requires periodic retesting for quality assurance purposes. The timeline for retesting is every 3,000 operating hours or the five year anniversary of the operating permit, whichever is sooner. These requirements are difficult to implement and to track. The permit anniversary date is not a good reference point. Also, the rule does not indicate whether the 3,000 operating hours are fuel-specific.

Discussion of Proposed Changes. Today's proposal would revise appendix E, section 2.2, to require retesting for all fuels, once every 20 calendar quarters. The quarter of the last test would serve as the reference point, similar to the methodology used for setting RATA and fuel flowmeter accuracy test deadlines. Fuel-specific missing data procedures would be used when a retest is not completed by the deadline. For each fuel, the new correlation curve obtained in a retest would be used for reporting, beginning with the first operating hour in which the fuel is combusted after completion of the retest. This is analogous to the part 75 requirement to apply CEMS bias adjustment factors beginning with the first operating hour after completion of a RATA.

3. How Will the Timeline for Unscheduled Appendix E Retests Be Revised?

Background. Section 2.3 of appendix E requires retesting within 10 unit operating days or 180 calendar days (whichever occurs first) whenever the monitored operating parameters are exceeded for more than 16 consecutive hours or the data availability, since the last test, is less than 90 percent. For many units, 10 operating days is not a sufficient amount of time to schedule a retest and perform the testing.

Discussion of Proposed Changes. EPA proposes to revise appendix E, section 2.3, to change the 10 unit operating day requirement to 30 unit operating days. This change would provide sufficient time to schedule and perform the tests and to meet the applicable test notification requirements.

4. How Will Appendix E Missing Data Procedures Be Changed?

Background. For missing data purposes, appendix E prescribes that the highest NO_X emission rate from the most recent set of baseline correlation tests be reported for each hour of the missing data period. There are three situations for which this missing data scheme may be inappropriate: (1) When the measured hourly heat input rate is higher than the highest heat input rate from the baseline correlation tests; (2) for a unit with add-on NO_X controls, if the controls are not in operation or it is not possible to document that the controls are operating properly; and (3) when emergency fuel is combusted.

Discussion of Proposed Changes. To address the concerns about situations in which the current missing data procedures may be inappropriate, the proposed rule would add to section 2.5 of appendix E a requirement to calculate a fuel-specific maximum potential NO_X emission rate (MER) for each type of fuel combusted by the unit and would add three new sections, 2.5.2.1, 2.5.2.2, and 2.5.2.3, to require reporting of the fuel-specific NO_X MER for cases (2), and (3), described above. For fuel mixtures, EPA would require substitution of the highest MER value for the fuels in the mixture.

For case (1) described above, two reporting options would be allowed. Whenever the heat input rate for a given unit operating hour exceeds the highest heat input rate from the baseline correlation tests, the owner or operator could either: (a) Report the hourly NO_X emission rate as the higher of the linear extrapolation of the correlation curve or the fuel-specific MER; or (b) report 1.25 times the highest NO_X emission rate on the correlation curve, not to exceed the fuel-specific MER. Note that for units with NO_X emission controls, the use of an extrapolated NO_X emission rate under (a), above, and the use of 1.25 times the highest value on the correlation curve under (b), above, would be disallowed, and the MER would have to be reported for any hour in which the emission controls could not be documented to be in proper operation.

5. How Will the Appendix E Testing Requirements for Emergency Fuel Be Changed?

Background. The current rule allows the designated representative for an appendix E unit to petition the Administrator for an exemption from appendix E testing for emergency fuel. Many Phase II Acid Rain units submitted such petitions with their initial certification applications, and the petitions were approved.

Discussion of Proposed Changes. Today's proposed rule would revise section 2.1.4 of appendix E to remove the requirement to petition the Administrator to obtain an exemption from appendix E testing for emergency fuel. EPA believes that the petition process is unnecessary, provided that the unit has a federally enforceable permit which restricts the combustion of a particular fuel to emergency situations. Therefore, the proposed rule would exempt emergency fuel from appendix E testing if the unit has the necessary permit and if documentation is provided in the monitoring plan for the unit.

M. Reference Methods

1. Which Code of Federal Regulations Versions of Reference Methods Are To Be Used?

Background. In the May 26, 1999 revisions to part 75, EPA specified that only particular versions of Reference Methods 6C, 7E, and 3A (the methods used for gas RATAs) be used. Those versions are the 1995, 1996, and 1997 Code of Federal Regulations versions of the methods. This provision was added to the rule because EPA at that time had proposed substantive revisions to these methods for the New Source Performance Standards (NSPS) Program that were not appropriate for the Acid Rain Program. However, the revisions to the reference methods were never finalized, therefore the reference to particular versions is no longer needed. Removing the caveat will eliminate confusion because these reference methods have been basically the same in all versions of the Code of Federal Regulations, from 1988 through 1999.

Discussion of Proposed Changes. Today's proposal would revise § 75.22(a) and appendix A, section 6.5.6, to remove from the rule all references to the 1995, 1996, and 1997 Code of Federal Regulations versions of Reference Methods 6C, 7E, and 3A.

2. Are There Other Changes to Reference Methods?

Background. Three issues have arisen regarding the part 60 reference test methods used to certify and quality assure part 75 CEMS. First, when measurement of the stack gas moisture content is required to determine the stack gas molecular weight, § 75.22(a)(4) allows the source to use any of the alternative moisture techniques listed in section 1.2 of Method 4. This includes, among other things, ''previous experience.'' Second, when an automated version of Method 2 is used for flow RATA testing, often all four available sample ports are occupied simultaneously with velocity probes which are bolted in place. This can make it difficult to obtain a moisture sample once every three runs or once every clock hour, as required in section 6.5.7 of appendix A. Third, questions have arisen regarding the manner in which NO_X compliance tests and RATAs are performed for combustion turbines.

Discussion of Proposed Changes. Today's proposed rule would revise § 75.22(a)(4), to clarify that for purposes of determining the stack gas molecular weight during a part 75 flow RATA, the only acceptable alternative moisture methodology listed in section 1.2 of Method 4 is the wet bulb-dry bulb measurement technique. The other methodologies listed (''drying tubes,'' ''condensation techniques,'' ''stoichiometric calculations,'' and ''previous experience'') are not defined precisely enough to approve their use. In contrast, the wet bulb-dry bulb technique is well-established and is generally familiar to emission testers.

Today's proposal would also revise section 6.5.7 of appendix A to allow, for purposes of determining stack gas molecular weight during part 75 flow RATAs, moisture measurements to be made before and after a series of RATA runs at a particular load level (low, mid, or high), in lieu of measuring moisture every three runs or once every clock hour, as required by the current rule. The results of the before and after moisture measurements would be averaged arithmetically, and the average value would be applied to all RATA runs in the series. Note, however, that this moisture measurement option could only be used if the before and after runs were performed no more than three hours apart. Section 6.5.7 would be further revised by clarifying that sufficient measurement time must be allowed at each traverse point of a flow RATA to ensure that stable temperature readings are obtained, particularly for the first point at which data are taken after a probe is moved from one port to the next.

Finally, today's proposed rule would revise § 75.22 and section 6.5.10 of appendix A, to allow the use of EPA Method 20, as an alternative to Method 7E, for relative accuracy test audits (RATAs) of NO_X monitoring systems installed on combustion turbines. Further, the proposed rule would revise section 6.5.6(b) of appendix A, to allow the reference method measurement points specified in section 6.1.2 of Method 20 to be used for a Method 7E RATA of a NO_X monitoring system installed on a combustion turbine. EPA believes these added flexibilities will simplify certification and quality assurance testing for combustion turbines. The rationale for these two new provisions follows.

Many utilities are constructing new gas turbines. Almost invariably, NO_X monitoring systems will be installed on these units. EPA Method 20 is the NO_X compliance test method for new gas turbines, under subpart GG of 40 CFR part 60, the New Source Performance Standards (NSPS) for stationary sources. Method 7E is the method currently prescribed by part 75 as the reference method for NO_X RATAs. Today's proposed rule would allow Method 20 data to be used for a dual purpose, that is, as compliance test data for NSPS and as reference method test data for the RATA of the part 75 NO_X monitoring system. This would make a second reference method test using Method 7E unnecessary.

EPA believes that for a Method 7E RATA of a NO_X monitoring system installed on a combustion turbine, allowing the Method 20 sample points to be used as the reference method measurement points is potentially beneficial, particularly if the stack or duct being tested is rectangular. The provisions in section 3.2 of Performance Specification No. 2 (PS No. 2) in appendix B of 40 CFR part 60 specify the required reference method measurement points for gas monitor RATAs. However, section 3.2 of PS No. 2 only addresses the point layout for circular stacks. There are no clear guidelines for rectangular stacks or ducts. On the other hand, section 6.1.2 of Method 20 does have a procedure for selecting reference method measurement points which applies to both circular and rectangular stacks or ducts.

N. Appendix G Revisions

Background and Discussion of Proposed Changes. Today's proposed rule would revise section 2.3 of appendix G to expand the applicability of Equation G–4 to oil-fired units. Currently, section 2.3 restricts the use of Equation G–4 to gas-fired units (as defined in § 72.2). There is no technical reason to prohibit the use of this equation by oil-fired units. Many gas-fired units that currently use Equation G–4 occasionally combust fuel oil. During the oil-burning hours, Equation G–4 is still used to report CO_2 emissions, except that an F_C factor of 1,420 scf/mmBtu (for oil) instead of the usual F_C factor of 1,040 scf/mmBtu for natural gas is used. Allowing the use of Equation G–4 for oil-fired units would enable the owner or operator to report hourly CO_2 emissions in tons per hour, instead of using Equation G–1, which requires CO_2 reporting on a tons per day basis. This option would not only simplify emission reporting for oil-fired units but would enable EPA to perform meaningful electronic audits of the reported CO_2 emissions, as the hourly heat input (i.e., the term ''H'' in Equation G–4) is the only variable in Equation G–4 and is required to be reported each hour in the EDR. However, the cumbersome term W_C (i.e., lbs of carbon burned per day) in Equation G–1 is not reported anywhere in the EDR.

O. Technical Changes and Corrections

Background. An important objective of this proposed rulemaking is to make technical changes and corrections to part 75. These changes and corrections are necessary to eliminate printing, typographical, and grammatical errors, to correct or clarify cross references, and, in a few instances, to ensure that the specific rule language is consistent with the Agency's intent. None of these technical corrections and changes adds new requirements or substantively affects the obligations of the entities that must comply with part 75 requirements.

The technical changes and corrections fall into several categories. In the first category are efforts to rewrite rule provisions to increase clarity and to accord with other provisions of part 75. In the second category are corrections and clarifications of equations, including the definitions of certain variables. The final category of technical changes consists of corrections of printing, typographical, and grammatical errors. Included in this category are repetitive words and phrases, misspelled words, and misplaced punctuation.

Discussion of Proposed Changes. The technical support document (Docket A–2000–33, Item II–A–2) provides a specific description for each of these technical changes and corrections.

P. What Other Changes is EPA Proposing to the Federal NO_X Budget Trading Program Today?

Background and Discussion of Proposed Changes. We are proposing a number of minor changes to the Federal NO_X Budget Trading Program in part 97 to correct errors or clarify provisions. For example, one proposed change is to correct the definition of ''percent monitor data availability'' in § 97.2. This definition is used to allow units to qualify for early reduction credits in § 97.43(a)(1) or to qualify to use data as a baseline for allowance allocations for opt-in units under § 97.84(b). EPA intended to make this definition consistent with the term's use in the part 75 monitoring rule, except that ''percent monitor data availability'' would apply only for an ozone season instead of for a year's worth of data on a rolling basis. Some companies have pointed out that the current definition is inconsistent because hours when the unit does not operate are still used in the calculation. This means that a unit might not be able to meet the required 90 percent monitor data availability simply because the unit does not operate for many hours during the ozone season. EPA is proposing to revise the definition so that it refers to the percentage of unit operating hours with valid, quality-assured data during an ozone season, rather than the percentage of all 3,672 hours during an ozone season.

As a further example of changes to part 97, the definition of '' NO_X allowance'' in § 97.2 provides that the term includes NO_X allowances from an approved State NO_X Budget Trading Program, except for purposes of certain listed sections relating to allocations. Section 97.40, defining the trading program budget, is added to that list of sections. In addition, EPA is correcting the reference in § 97.42(e)(2) to allowances ''deducted under paragraph (c)(1) of this section'' to refer instead to ''paragraph (e)(1) of this section.'' Other proposed changes to part 97 are addressed in a technical support document (Technical Support Document, Docket A–2000–33, Item II–A–2). EPA believes these minor changes may reduce confusion and improve consistency within part 97.

Finally, EPA is proposing a number of other minor changes to part 78 to make existing administrative appeal procedures applicable to decisions of the Administrator under part 97. The changes to part 78 are addressed in a technical support document (Technical Support Document, Docket A–2000–33, Item II–A–2).

IV. Administrative Requirements

A. Public Hearing

If requested as specified in the **DATES** section of this document, a public hearing will be held to discuss the proposed regulations. Persons wishing to make oral presentations at the public hearing should contact EPA at the address given in the **ADDRESSES** section of this document. If necessary, oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement with EPA before, during, or within 30 days of the hearing. Written statements should be addressed to the Air Docket address given in the **ADDRESSES** section of this document.

A verbatim transcript of the public hearing, if held, and all written statements will be available for public inspection and copying during normal working hours at EPA's Air Docket in Washington, DC (see the **ADDRESSES** section of this document).

B. Public Docket

The Docket for this regulatory action is A–2000–33. The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of this proposed rulemaking. The principal purposes of the docket are: (1) To allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review. The docket is available for public inspection at EPA's Air Docket, which is listed under the **ADDRESSES** section of this document.

C. Executive Order 12866

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Administrator must determine whether the regulatory action is ''significant'' and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

This proposed rule is not expected to have an annual effect on the economy of $100 million or more. However, pursuant to the terms of Executive Order 12866, it has been determined that this proposed rule is a significant action because it raises novel policy issues. As such, the proposed rule has been submitted for OMB review. Any written comments from OMB and any EPA response to OMB comments are in the public docket for this proposal.

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.

This proposed rule is not expected to result in expenditures of more than $100 million in any one year and, as such, is not subject to section 202 of the UMRA. EPA will continue to use its outreach efforts related to part 75 implementation, including a policy manual that is updated regularly, to inform, educate, and advise all potentially impacted small governments about compliance with part 75.

E. Paperwork Reduction Act

The information collection requirements in 40 CFR parts 72, 75, 78 and 97 affect two EPA programs, the Acid Rain Program and the Federal NO_X Budget Trading Program. There are two program ICRs currently in place that account for the basic recordkeeping and reporting burdens associated with 40 CFR parts 72, 75, 78 and 97. First, the Acid Rain Program ICR1633.12, (OMB No. 2060–0258) addresses the costs for units affected by the Acid Rain Program. The NO_X SIP Call ICR1857.02, (OMB No. 2060–0445) addresses the costs, including NO_X mass monitoring costs, by both Acid Rain Program (ARP) units and non-ARP units in the NO_X Budget Trading Program.

Most of the changes associated with this rulemaking are aimed at fine tuning the regulations in response to issues raised during the ongoing implementation of part 75. Thus, they do not significantly affect the burden estimates included in the two existing ICRs. Table 1, below, categorizes the proposed changes to parts 72 and 75, and proposed associated changes to part 97, as recordkeeping and reporting burden/cost neutral or as burden/cost reducing; none of the changes is expected to significantly increase burdens or costs. (The remaining changes to parts 72, 78, and 97 do not affect recordkeeping and reporting requirements.)

Further, the Agency expects the changes to have minimal impact on existing program ICRs because many of the changes merely serve to make additional flexibilities feasible. For example, many of the proposed rule revisions to the LME section will clarify how the rule applies to non-ARP SIP Call units that use part 75 for NO_X mass monitoring. The existing rule language is unclear for these non-ARP units. The changes make use of the LME provisions feasible for non-ARP units so that the scope of applicability to non-ARP units is not expected to be significantly different than that for ARP units.

The SIP Call ICR assumed none of the non-ARP units would take advantage of the reduced burdens and costs associated with the LME provisions because those estimates only related to burden incurred through the year 2002. In future years, as LMEs avail themselves of the proposed provisions, it is estimated that there will be burden reductions. These reductions will be reflected in the next revisions to the SIP Call ICR.

Table 1—Summary of Impacts of Major Rule Revisions

A. Rule Revisions Assumed To Be Cost/Burden Neutral
- Pipeline natural gas definition revision, and other definition clarifications
- Standardization of deadlines for various activities/reports/notices
- Data validation clarifications
- Span/range clarifications
- Bypass monitoring flexibility changes
- Clarifications for Subpart H missing data
- General LME clarifications
- Missing data options relating to fuel type, degree of control, and non-load based units
- Alternative bypass stack monitoring options
- Other miscellaneous changes

B. Rule Revisions Assumed To Decrease Costs/Burdens
- Expanded clarification of LME for Subpart H monitoring

Although not indicated in Table 1, there are two primary ways in which the proposed parts 72, 75 and 97 revisions could result in some increased burden or cost. First, the regulated industry and State and local agencies involved with part 75 monitoring will have to review the revised regulation to understand the changes. The existing ARP and SIP Call ICRs have accounted for this increase in a line item for ongoing rule review. Nevertheless, it is important to note that new units just initiating part 75 monitoring in response to the NO_X SIP Call will experience less burden as a consequence of the numerous clarifications, the specific changes to address NO_X mass monitoring issues, and the removal of outdated sections. Taken as a whole, EPA does not believe that the regulatory review burdens will be affected significantly.

The second type of burden or cost increase would be associated with any required data acquisition and handling system (DAHS) software changes that may be necessary to the extent the rule revisions affect recording and reporting data in the required electronic data formats. Generally, EPA has attempted to minimize any DAHS impacts associated with these revisions. There are some optional elements of the proposed revisions that would require DAHS software changes, but only if the owner or operator decides to take advantage of the option for its circumstances. EPA believes many sources will only avail themselves of these types of changes as part of other routine monitoring system component upgrades. Consequently, the expected impact in this area is also expected to be minimal. An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

The Agency requests comment on its assessment of information burden imposed by these requirements. An ICR amendment was not prepared because the changes were anticipated to be minimal in the context of the two existing ICRs. Send comments on the ICRs to the Director, Collection Strategies Division; U.S. Environmental Protection Agency (2822); 1200 Pennsylvania Ave., NW, Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th St., NW, Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Include the ICR in any correspondence. Additional information in support of the Agency's estimate is contained in the docket for this proposed rulemaking.

F. Regulatory Flexibility

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601, *et seq.*, generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and governmental jurisdictions.

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this proposed action. For the Acid Rain Program, these proposed revisions would not result in increased impacts to small entities.

For these reasons, I certify that today's proposed rule would not have a significant, economic impact on a substantial number of small entities.

G. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 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, business practices, etc.) that are developed or adopted by voluntary consensus standards bodies. The NTTAA requires EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

EPA invites public comment on the voluntary consensus standards which are proposed to be incorporated by reference for use in part 75. EPA has not identified any additional voluntary consensus standards which might be applicable to this rulemaking. This does not indicate that other applicable standards do not exist or that any other standards should not be allowed. Therefore, EPA also invites public comment on any other voluntary consensus standards which may be appropriate for the proposed regulatory action. Further, if additional applicable voluntary consensus standards are identified in the future, the designated representative may petition under § 75.66(c) to use an alternative to any standard incorporated by reference and prescribed in this part.

H. Executive Order 13175

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 6, 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.'' ''Policies that have tribal implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes.''

This proposed rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this rule.

In the spirit of Executive Order 13175, and consistent with EPA policy to promote communications between EPA and tribal governments, EPA specifically solicits additional comment on this proposed rule from tribal officials.

I. Executive Order 12898

Executive Order 12898 requires that each federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. The technical revisions in this proposed rule to various monitoring and other requirements would have no impact on emission levels or the location of emission reductions. Thus, the proposed rule revisions would not have a disproportionately high and adverse impact on minorities or low-income populations.

J. Executive Order 13045

Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), applies to any rule that the Agency determines (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.

Today's proposed rule is not subject to Executive Order 13045 because it is not expected to have an annual effect on the economy of $100 million or more. Further, EPA does not have reason to believe that the environmental health risks or safety risks addressed by this action present a disproportionate risk to children.

K. Executive Order 13132

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'' are 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.''

Under section 6 of Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

The rule revisions in this proposed action 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. This proposed action does not create a mandate upon State, local, or tribal governments, except to the extent such governments own or operate an affected source. Even in those cases, the proposed rule revisions do not have federalism implications and do not impose significant compliance costs beyond the costs already incurred under part 75.

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.

List of Subjects

40 CFR Part 72

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

40 CFR Part 75

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

40 CFR Part 78

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

40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Continuous emission monitoring, Electric utilities, NO_X Budget Program, Reporting and recordkeeping requirements.

Dated: May 16, 2001.

Christine Todd Whitman,

Administrator.

For the reasons set out in the preamble, title 40 chapter I of the Code of Federal Regulations is proposed to be amended as follows:

PART 72—PERMITS REGULATION

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

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

2. Section 72.2 is amended by:

a. Revising the definitions of ''Cogeneration unit'', ''Continuous emission monitoring system or CEMS'', ''Hour before and after'', ''Maximum potential NO_X emission rate'', ''Missing data period'', ''Monitor accuracy'', ''Pipeline natural gas'', ''Stack operating hour'', and ''Unit operating hour'';

b. In the definition of ''Automated data acquisition and handling system'' by adding the words ''moisture monitors,'' before the word ''opacity'';

c. In the definition of ''By-pass stack'' by removing the hyphen from the word ''bypass'';

d. In paragraph (1) of the definition of ''Calibration error'' by adding the word ''a'' before the words ''gaseous monitor'';

e. In the definition of ''Compliance plan'' by adding a closing parenthesis after the second instance of the words ''part 76 of this chapter'';

f. In the definition of ''Continuous opacity monitoring system or COMS'' by revising the words ''systems are component parts'' in the second sentence to read ''components are'', and in paragraph (2) by revising the word ''A'' to read ''An automated'';

g. Revising paragraph (2) of the definition of ''Emergency fuel'';

h. In the definition of ''Fuel flowmeter QA operating quarter'' by adding the word ''cumulative'' after the words ''at least 168'' and removing the words ''or more'' at the end of the definition;

i. Remove the definition of ''Heat input'' and add in its place a new definition ''*Heat input rate*'';

j. Remove the definition of ''Maximum rated hourly heat input'' and add in its place the definition for ''*Maximum rated hourly heat input rate*'';

k. In the definition of ''Natural gas'' by revising the second sentence and by removing the word ''meet'', and replacing the ''%'' symbol with the word ''percent'' in the third sentence;

l. In the definition of ''QA operating quarter'' by adding the word ''cumulative'' after each occurrence of the words ''at least 168'';

m. In the definition of ''Relative accuracy'' by adding the words ''or moisture'' after the words ''between the pollutant'' and by adding the words ''or moisture monitor'' after the words ''flow monitor'';

n. Adding in alphabetical order new definitions for ''Common pipe'', ''Common pipe operating time'', ''Cumulative stack operating hours'', ''Cumulative unit operating hours'', ''Diluent cap value'', ''Fuel flowmeter system'', ''Fuel usage time'', ''Multiple stack configuration'', ''Stack operating time'', and ''Unit operating time''.

The revisions and additions read as follows:

§ 72.2 Definitions.

* * * * *

Cogeneration unit means a unit that produces electric energy and useful thermal energy for industrial, commercial, or heating or cooling purposes, through the sequential use of the original fuel energy.

* * * * *

Common pipe means an oil or gas supply line through which the same type of fuel is distributed to two or more affected units.

Common pipe operating time means the portion of a clock hour during which fuel flows through a common pipe. The common pipe operating time, in hours, is expressed as a decimal fraction, with valid values ranging from 0.00 to 1.00.

* * * * *

Continuous emission monitoring system or CEMS means the equipment required by part 75 of this chapter used to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2, NO_X, or CO_2 emissions or stack gas volumetric flow rate. The following are the principal types of continuous emission monitoring systems required under part 75 of this chapter. Sections 75.10 through 75.18 and § 75.71(a) of this chapter indicate which type(s) of CEMS is required for specific applications:

(1) A sulfur dioxide monitoring system, consisting of an SO_2 pollutant concentration monitor and an automated DAHS. An SO_2 monitoring system provides a permanent, continuous record of SO_2 emissions in units of parts per million (ppm);

(2) A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS. A flow monitoring system provides a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);

(3) A nitrogen oxides (NO_X) emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated DAHS. A NO_X-diluent monitoring system provides a permanent, continuous record of: NO_X concentration in units of parts per million (ppm), diluent gas concentration in units of percent O_2 or CO_2 (percent O_2 or CO_2), and NO_X emission rate in units of pounds per million British thermal units (lb/mmBtu);

(4) A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated DAHS. A NO_X concentration monitoring system provides a permanent, continuous record of NO_X emissions in units of parts per million (ppm). This type of CEMS is used only in conjunction with a flow monitoring system to determine NO_X mass emissions (in lb/hr) under subpart H of part 75 of this chapter;

(5) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and the automated DAHS. A carbon dioxide monitoring system provides a permanent, continuous record of CO_2 emissions in units of percent CO_2 (percent CO_2); and

(6) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter. A moisture monitoring system provides

a permanent, continuous record of the stack gas moisture content, in units of percent H_2O (percent H_2O).

* * * * *

Cumulative stack operating hours means the sum of the stack operating times (as defined in this section) for a series of consecutive stack operating hours (as defined in this section), rounded to the nearest hour.

Cumulative unit operating hours means the sum of the unit operating times (as defined in this section) for a series of consecutive unit operating hours (as defined in this section), rounded to the nearest hour.

* * * * *

Diluent cap value means a default CO_2 or O_2 concentration which may be used to calculate the hourly NO_X emission rate, CO_2 mass emission rate, or heat input rate, when the measured hourly average CO_2 or O_2 concentration is below the default value. The diluent cap values for boilers are 5 percent CO_2 and 14 percent O_2. For combustion turbines, the diluent cap values are 1 percent CO_2 and 19 percent O_2.

* * * * *

Emergency fuel means:

* * * * *

(2) For purposes of the requirement for stack testing for an excepted monitoring system under appendix E of part 75 of this chapter, the fuel identified in a federally-enforceable permit for a plant and identified by the designated representative in the unit's monitoring plan as the fuel which is combusted only during emergencies where the primary fuel is not available.

* * * * *

Fuel flowmeter system means an excepted monitoring system (as defined in this section) which provides a continuous record of the flow rate of fuel oil or gaseous fuel, in accordance with appendix D to part 75 of this chapter. A fuel flowmeter system consists of one or more fuel flowmeter components, all necessary auxiliary components (e.g., transmitters, transducers, etc.), and a data acquisition and handling system (DAHS).

* * * * *

Fuel usage time means the portion of a clock hour during which a unit combusts a particular type of fuel. The fuel usage time, in hours, is expressed as a decimal fraction, with valid values ranging from 0.00 to 1.00.

* * * * *

Heat input rate means the product (expressed in mmBtu/hr) of the gross calorific value of the fuel (expressed in mmBtu/mass of fuel) and the fuel feed rate into the combustion device (expressed in mass of fuel/hr) and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Hour before and *hour after* means, for purposes of the missing data substitution procedures of part 75 of this chapter, the quality-assured hourly SO_2 or CO_2 concentration, hourly flow rate, hourly NO_X concentration, hourly moisture, hourly O_2 concentration, or hourly NO_X emission rate (as applicable) recorded by a certified monitor during the unit or stack operating hour immediately before and the unit or stack operating hour immediately after a missing data period.

* * * * *

Maximum potential NO_X emission rate, or *MER* means the emission rate of nitrogen oxides (in lb/mmBtu) calculated in accordance with section 3 of appendix F to part 75 of this chapter, using the maximum potential nitrogen oxides concentration as defined in section 2.1.2.1 of appendix A to part 75 of this chapter, and either the maximum oxygen concentration (in percent O_2) or the minimum carbon dioxide concentration (in percent CO_2) under all operating conditions of the unit except for unit start-up, shutdown, and upsets. The diluent cap value, as defined in this section, may be used in lieu of the maximum O_2 or minimum CO_2 concentration to calculate the MER.

Maximum rated hourly heat input rate means a unit-specific maximum hourly heat input rate (mmBtu/hr) which is the higher of the manufacturer's maximum rated hourly heat input rate or the highest observed hourly heat input rate.

Missing data period means the total number of consecutive hours during which any certified CEMS or approved alternative monitoring system is not providing quality-assured data, regardless of the reason.

Monitor accuracy means the closeness of the measurement made by a CEMS to the reference value of the emissions or volumetric flow being measured, expressed as the difference between the measurement and the reference value.

* * * * *

Multiple stack configuration refers to an exhaust configuration in which the flue gases from a particular unit discharge to the atmosphere through two or more stacks. The term also refers to a unit for which emissions are monitored in two or more ducts leading to the exhaust stack, in lieu of monitoring at the stack.

* * * * *

Natural gas * * * Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. * * *

* * * * *

Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.

* * * * *

Stack operating hour means a clock hour during which flue gases flow through a particular stack or duct (either for the entire hour or for part of the hour) while the associated unit(s) are combusting fuel.

Stack operating time means the portion of a clock hour during which flue gases flow through a particular stack or duct while the associated unit(s) are combusting fuel. The stack operating time, in hours, is expressed as a decimal fraction, with valid values ranging from 0.00 to 1.00.

* * * * *

Unit operating hour means a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour.

* * * * *

Unit operating time means the portion of a clock hour during which a unit combusts any fuel. The unit operating time, in hours, is expressed as a decimal fraction, with valid values ranging from 0.00 to 1.00.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

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

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

§ 75.1 [Amended].

4. Section 75.1 is amended by adding the words ''(the Act)'' at the end of the first sentence of paragraph (a).

5. Section 75.4 is amended by:

a. In paragraph (b) introductory text by adding the word ''moisture,'' after the word ''opacity,'';

b. In paragraphs (b)(2) and (c)(2) by revising the words ''Not later than 90'' to read ''The earlier of 90 unit operating days or 180 calendar'';

c. Remove ''or'' at the end of paragraphs (b)(1) and (c)(1) and remove the period at the end of paragraphs (b)(2) and (c)(2) and add ''; or'' in its place;

d. Adding paragraphs (b)(3) and (c)(3);

e. In the first sentence of paragraph (d) by revising the words ''the earlier of 45'' to read ''90'', adding the words ''(whichever occurs first)'' following the words ''180 calendar days'', and removing the words ''of the affected unit'' after the words ''recommences commercial operation'';

f. In the first sentence of paragraph (e) introductory text by revising the words ''90 calendar days'' to read ''90 unit operating days or 180 calendar days (whichever occurs first)'';

g. Revising paragraphs (f) introductory text and (f)(1);

h. Removing and reserving paragraphs (g) and (h); and

i. In paragraph (i) by removing the word ''or'' in paragraph (i)(1) and by revising paragraphs (i)(2) and (i)(3).

The revisions and additions read as follows:

§ 75.4 Compliance dates.

* * * * *

(b) * * *

(3) The owner or operator shall determine and report SO_2 concentration, NO_X emission rate, CO_2 concentration, and flow data for all unit operating hours after the applicable compliance date in this paragraph until all required certification tests are successfully completed using either:

(i) The maximum potential concentration of SO_2, the maximum potential NO_X emission rate, as defined in section 2.1.2.1 of appendix A to this part, the maximum potential flow rate, as defined in section 2.1.4.1 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;

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

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

(c) * * *

(3) The owner or operator shall determine and report SO_2 concentration, NO_X emission rate, CO_2 concentration, and flow data for all unit operating hours after the applicable compliance date in this paragraph until all required certification tests are successfully completed using either:

(i) The maximum potential concentration of SO_2, the maximum potential NO_X emission rate, as defined in section 2.1.2.1 of appendix A to this part, the maximum potential flow rate, as defined in section 2.1.4.1 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;

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

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

* * * * *

(f) In accordance with § 75.20, the owner or operator of an affected gas-fired or oil-fired peaking unit, if planning to use appendix E of this part, shall ensure that the required certification tests for excepted monitoring systems under appendix E are completed for backup fuel, as defined in § 72.2 of this chapter, no later than 90 unit operating days or 180 calendar days (whichever occurs first) after the date that the unit first combusts the backup fuel following the certification testing with the primary fuel. Until all required certification tests are successfully completed, the owner or operator shall report NO_X emission rate data for all unit operating hours that the backup fuel is combusted using either:

(1) The fuel-specific maximum potential NO_X emission rate;

* * * * *

(i) * * *

(2) For a new affected unit which has not commenced commercial operation by January 2, 2000, 90 unit operating days or 180 calendar days (whichever occurs first) after the date the unit commences commercial operation; or

(3) For an existing unit that is shutdown and is not yet operating by April 1, 2000, 90 unit operating days or 180 calendar days (whichever occurs first) after the date that the unit recommences commercial operation.

§ 75.6 [Amended].

6. In § 75.6 amend paragraphs (a)(19), (a)(26), and (a)(35) by removing the words ''§ 75.15 and''.

7. Section 75.10 is amended by:

a. In paragraph (a)(1) by revising the word ''The'' in the first sentence to read ''To determine SO_2 emissions, the'', and by revising the words ''the automated'' to read ''an automated'';

b. In paragraph (a)(2) by revising the word ''The'' in the first sentence to read ''To determine NO_X emissions, the''; by revising the words ''the automated'' to read ''an automated''; and by revising the first occurrence of the word '' NO_X'' in the first sentence to read '' NO_X-diluent'';

c. In paragraph (a)(3)(i) by revising the words ''the automated'' to read ''an automated'';

d. In paragraph (a)(3)(iii) by revising the words ''using an O_2 concentration monitor in order'' to read ''that uses an O_2 concentration monitor'' and by revising the words ''using the procedures in appendix F of this part with the automated'' to read ''(according to the procedures in appendix F of this part) with an automated'';

e. Removing ''and'' at the end of paragraph (a)(3) and removing the period at the end of paragraph (a)(4) and adding ''; and'' in its place;

f. Adding new paragraph (a)(5);

g. In paragraph (c) by adding the word ''Rate'' after the words ''Heat Input'' in the heading and by adding the words ''rate, in units of mmBtu/hr,'' after the words ''record the heat input'';

h. In paragraph (d)(1) by removing the words ''and component thereof'' from the first sentence, removing the words ''SO_2 emission rate in lb/mmBtu (if applicable),'' from the second sentence, and by adding the word ''or'' after the words ''of this part,'' in the fourth sentence;

i. In paragraph (d)(3) by revising the words ''flow monitor, or NO_X'' to read '' NO_X concentration monitor, flow monitor, moisture monitor, or NO_X-diluent'', by revising the words ''An hourly average NO_X or SO_2'' in the second sentence to read ''For a NO_X-diluent monitoring system, hourly average NO_X'', by adding the word ''NO_X'' before the word ''pollutant'' and by removing the words ''(NO_X or SO_2)'' in the second sentence; and by revising in the fourth sentence the words ''Except for SO_2 emission rate data in lb/mmBtu, if'' to read ''If'';

j. In paragraph (f) by removing the words ''and component thereof''; and

k. Revising the capitalization in the title of paragraph (g) from ''Minimum Recording and Recordkeeping Requirements'' to ''Minimum recording and recordkeeping requirements''.

The revisions and additions read as follows:

§ 75.10 General operating requirements.

(a) * * *

(5) A single, certified flow monitoring system may be used to meet the requirements of paragraphs (a)(1) and (a)(3) of this section. A single certified diluent monitor may be used to meet the requirements of paragraphs (a)(2) and (a)(3) of this section. A single automated data acquisition and handling system may be used to meet the requirements of paragraphs (a)(1) through (a)(4) of this section.

* * * * *

§ 75.11 [Amended].

8. Section 75.11 is amended by:

a. Revising the word ''psychometric'' in paragraph (b)(2) to read ''psychrometric'';

b. In the second sentence of paragraph (e)(1) by adding the words ''(according to the applicable equation in section 5.2 of appendix F to this part)'' after the word ''monitor'', and removing the words ''and equation D–5 in appendix D to this part'';

c. In paragraph (e)(2) by revising in the first sentence the words ''§ 75.55 or § 75.58, as applicable,'' to read ''§ 75.58,'', and by, in the second sentence, adding the word ''rate'' after ''heat input'' and revising the words ''§ 75.54(b)(5) or § 75.57(b)(5), as applicable,'' to read ''§ 75.57(b)(5)'';

d. In paragraph (e)(3) by removing the third sentence, removing the period at the end of the second sentence and adding a semicolon, removing the words ''then on and after April 1, 2000,'' in the second sentence, and by revising the words ''be subject to'' to read ''meet'' in the second sentence; and

e. In the first sentence of paragraph (e)(3)(iii) by adding the words ''bias-adjusted'' before the words ''hourly average''.

9. Section 75.12 is amended by:

a. Revising the section heading;

b. In paragraph (a) by adding the word ''(CEMS)'' after the words ''continuous emission monitoring system'' in the first sentence and by revising the words '' NO_X continuous emission monitoring system'' to read '' NO_X-diluent CEMS'' in the second sentence;

c. In paragraph (d)(2) by revising the word '' NO_X'' to read '' NO_X-diluent'' in the second sentence and by adding a new third sentence; and

d. In paragraph (e) by revising the reference to ''(c)'' to read ''(d)''.

The revisions and additions read as follows:

§ 75.12 Specific provisions for monitoring NO_X emission rate (NO_X-diluent monitoring systems).

* * * * *

(d) * * *

(2) * * * If the required CEMS has not been installed and certified by that date, the owner or operator shall report the maximum potential NO_X emission rate (MER) (as defined in § 72.2 of this chapter) for each unit operating hour, starting with the first unit operating hour after the deadline and continuing until the CEMS has been provisionally certified. For each unit operating hour in which the MER is reported, the MER shall be specific to the type of fuel being combusted in the unit.

* * * * *

10. Section 75.13 is amended by:

a. Revising the heading and first sentence of paragraph (b); and

b. Revising the first sentence of paragraph (c).

The revisions and additions read as follows:

§ 75.13 Specific provisions for monitoring CO_2 emissions.

* * * * *

(b) *Determination of CO_2 emissions using appendix G to this part.* If the owner or operator chooses to use the appendix G method, then the owner or operator shall follow the procedures in appendix G to this part for estimating daily CO_2 mass emissions based on the measured carbon content of the fuel and the amount of fuel combusted. * * *

(c) *Determination of CO_2 mass emissions using an O_2 monitor according to appendix F to this part.* The owner or operator shall determine hourly CO_2 concentration and mass emissions with a flow monitoring system; a continuous O_2 concentration monitor; fuel F and F_C factors; and, where O_2 concentration is measured on a dry basis (or where Equation F–14b in appendix F to this part is used to determine CO_2 concentration), either a continuous moisture monitoring system, as specified in § 75.11(b)(2), or a fuel-specific default moisture percentage (if applicable), as defined in § 75.11(b)(1); and by using the methods and procedures specified in appendix F to this part. * * *

* * * * *

§ 75.15 [Reserved].

11. Section 75.15 is removed and reserved.

12. Section 75.16 is amended by:

a. Removing and reserving all of paragraph (a);

b. Revising paragraph (b) heading and introductory text and paragraph (c);

c. Amending paragraphs (e) heading and introductory text, (e)(1), (e)(2), (e)(3), and (e)(4) by adding the word ''rate'' after each occurrence of the words ''heat input'' except for the last occurrence in paragraph (e)(1);

d. In paragraph (e)(1) by revising the reference to ''(a)'' to read ''(b)'' in the first sentence, and by removing ''(a)(1)(ii), (a)(2)(ii),'' and the comma after ''(b)(1)(ii)'' in the third sentence;

e. In paragraph (e)(2) by revising the words ''appendix F of this part'' to read ''appendix F to this part''; and

f. In paragraph (e)(3) by adding the words '', in conjunction with the appropriate unit and stack operating times'' after the words ''utilizing the common stack''.

The revisions and additions 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) *Common stack procedures.* The following procedures shall be used when more than one unit uses a common stack:

* * * * *

(c) *Unit with bypass stack.* Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack so as to avoid the installed SO_2 continuous emission monitoring system and flow monitoring system, the owner or operator shall either:

(1) Install, certify, operate, and maintain separate SO_2 continuous emission monitoring systems and flow monitoring systems on the main stack and the bypass stack and calculate SO_2 mass emissions for the unit as the sum of the SO_2 mass emissions measured at the two stacks; or

(2) Monitor SO_2 mass emissions at the main stack using SO_2 and flow rate monitoring systems and measure SO_2 mass emissions at the bypass stack using the reference methods in § 75.22(b) for SO_2 and flow rate and calculate SO_2 mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems; or

(3) Install, certify, operate, and maintain SO_2 and flow rate monitoring systems only on the main stack. If this option is chosen, report the following values for each hour during which emissions pass through the bypass stack: the maximum potential concentration of SO_2 as determined under section 2.1.1.1 of appendix A to this part (or, if available, the SO_2 concentration measured by a certified monitor located at the control device inlet), and the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part. If the bypass stack is also unmonitored for NO_X, CO_2, or moisture, report the following values for each hour in which the bypass stack is used: the maximum potential CO_2 concentration, as defined in section 2.1.3.1 of appendix A to this part, the maximum potential NO_X emission rate, as defined in section 2.1.2.1(b) of appendix A to this part, the minimum potential moisture percentage, as defined in section 2.1.5 of appendix A to this part, and, if O_2 concentration is used to determine the hourly heat input rate, report the minimum potential O_2 concentration (as defined in section 2.1.3.2 of appendix A to this part). The maximum potential SO_2 concentration and the maximum potential NO_X

emission rate shall be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(b)(5)). This option may only be used if use of the bypass stack is limited to unit startup, emergency situations (e.g., malfunction of a flue gas desulfurization system), and periods of routine maintenance of the flue gas desulfurization system or maintenance 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 SO_2, flow rate, or any other parameter that is monitored only at the main stack.

* * * * *

13. Section 75.17 is amended by:

a. Removing the hyphen from the word ''by-pass'' in the section heading;

b. In the introductory text by revising the words ''and (c)'' to read ''(c), and (d)'';

c. In paragraph (b)(1) by revising the word ''NO_X'' to read ''NO_X-diluent'';

d. Revising the paragraph heading and first sentence of paragraph (c) introductory text;

e. Revising paragraphs (c)(1) and (c)(2); and

f. Adding new paragraph (d).

The revisions and additions read as follows:

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

* * * * *

(c) *Unit with multiple stacks or ducts.* When the flue gases from an affected unit discharge to the atmosphere through two or more stacks or when flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than the stack, the owner or operator shall monitor the NO_X emission rate in a way that is representative of each affected unit. * * *

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emission monitoring system and a flow monitoring system in each stack or duct and determine the NO_X emission rate for the unit as the Btu-weighted average of the NO_X emission rates measured in the stacks or ducts using the heat input estimation procedures in appendix F to this part. Alternatively, for units that are eligible to use the procedures of appendix D to this part, the owner or operator may monitor heat input and NO_X emission rate at the unit level, in lieu of installing flow monitors on each stack or duct. If this alternative unit-level monitoring is performed, report, for each unit operating hour, the highest emission rate measured by any of the NO_X-diluent monitoring systems installed on the individual stacks or ducts as the hourly NO_X emission rate for the unit, and report the hourly unit heat input as determined under appendix D to this part. Also, when this alternative unit-level monitoring is performed, the applicable NO_X missing data procedures in §§ 75.31 or 75.33 shall be used for each unit operating hour in which a quality-assured NO_X emission rate is not obtained for one or more of the individual stacks or ducts; or

(2) Provided that the products of combustion are well-mixed, install, certify, operate, and maintain a NO_X continuous emission monitoring system in one stack or duct from the affected unit and record the monitored value as the NO_X emission rate for the unit. The owner or operator shall account for NO_X emissions from the unit during all times when the unit combusts fuel. Therefore, this option shall not be used if the monitored stack or duct can be bypassed (e.g., by using dampers). Follow the procedure in § 75.17 for units with bypass stacks. Further, this option shall not be used unless the monitored NO_X emission rate truly represents the NO_X emissions discharged to the atmosphere (e.g., the option is disallowed if there are any additional NO_X emission controls downstream of the monitored location).

(d) *Unit with a main stack and bypass stack configuration.* For an affected unit with a discharge configuration consisting of a main stack and a bypass stack, the owner or operator shall either:

(1) Follow the procedures in paragraph (c)(1) of this section; or

(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, report the maximum potential NO_X emission rate (as defined in § 72.2 of this chapter). The maximum potential NO_X emission rate shall be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). In addition, if SO_2, CO_2, flow rate, or (if applicable) moisture monitoring systems are installed only on the main stack and not on the bypass stack, report the following values for each hour in which the bypass stack is used: The maximum potential values of SO_2 concentration, CO_2 concentration, and stack gas flow rate, as defined in section 2 of appendix A to this part, the minimum potential moisture percentage, as defined in section 2.1.5 of appendix A to this part, and, if O_2 concentration is used to determine the hourly heat input rate, report the minimum potential O_2 concentration (as defined in section 2.1.3.2 of appendix A to this part). If SO_2 emissions and the unit heat input are determined using a fuel flowmeter in accordance with appendix D to this part and if CO_2 emissions are estimated using the procedures in appendix G to this part, report SO_2 emissions and CO_2 emissions in accordance with appendices D and G to this part, and report the actual measured heat input rate for each hour in which the bypass stack is used.

14. Section 75.19 is amended by:

a. Revising paragraphs (a)(1)(i), (a)(1)(ii), (a)(2)(i), (a)(2)(ii), (b)(1), (b)(2), (b)(3), (c)(1)(iv)(A), (c)(1)(iv)(C), and (c)(3)(ii)(H);

b. In paragraph (b)(4) introductory text by revising the words ''unit commencing operation after January 1, 1997'' to read ''new or newly-affected unit'';

c. In paragraph (b)(4)(ii) by revising the words '' NO_X, and CO_2'' to read ''CO_2, and/or NO_X'';

d. In paragraph (b)(4)(iii) by revising the words ''and NO_X'' in the first sentence to read ''and/or NO_X'' and by revising the words ''tables 1, 2 and 3'' to read ''tables LM–1, LM–2, and LM–3'' in the second sentence;

e. Removing and reserving paragraph (c)(1)(iv)(B)(*3*);

f. In paragraph (c)(1)(iv)(B)(*4*) by revising the reference to ''(c)(1)(iv)(B)(*3*)'' to read ''(c)(1)(iv)(B)(*1*)'';

g. In the first sentence of paragraph (c)(1)(iv)(D) by revising the words '', each unit in a group of units sharing a common fuel supply, or'' to read ''or group of'';

h. In paragraph (c)(1)(iv)(E) by removing the words '', each low mass emission unit in a group of units combusting a common fuel,'';

i. Revising the first and last sentences of (c)(1)(iv)(G);

j. In the first sentence of (c)(1)(iv)(H) by adding the words ''(including units that use dry low-NO_X technology),'' after the first occurrence of the words ''NO_X emission controls'';

k. In the last sentence of (c)(1)(iv)(H)(*1*) by adding the words '', and the appropriate default NO_X emission rate from Table LM–2 shall be reported instead'' after the words ''for that hour'';

l. Adding new paragraph (c)(1)(iv)(I);

m. In paragraph (c)(2)(iii) by revising the word ''output'' to read ''load'' and adding the words ''per hour'' after the words ''pounds of steam'';

n. In paragraph (c)(2)(iv) by adding the words ''add-on'' after the words ''unit with'' and adding the words ''(including dry low-NO_X technology)'' after the words ''of any kind'';

o. In paragraph (c)(3)(i) by adding ''HI_{hr},'' after the words ''of this section,'' in the first sentence, by revising Eq. LM–1 and the accompanying variable definitions, and by adding a new paragraph (c)(3)(i)(D);

p. Removing the word ''use'' in the second sentence of paragraph (c)(3)(ii)(D)(*1*);

q. Adding a sentence following the first sentence of paragraphs (c)(3)(ii)(E), (c)(3)(ii)(G), and (c)(4)(ii)(C);

r. In the definition of M_{qtr} in Equation LM–2 in paragraph (c)(3)(ii)(E) by removing the word ''entire'';

s. In the definition of Q_g in Equation LM–3 in paragraph (c)(3)(ii)(E) by revising the word ''Value'' to read ''Volume'' and adding parentheses around the words ''standard cubic feet (scf)'';

t. In paragraph (c)(3)(ii)(F) by adding the words '', using Equation LM–4'' after the reference to ''LM–3'';

u. Revising the definition of variables following Equations LM–7 and LM–8 in paragraph (c)(3)(ii)(I), the definition of variables following Equations LM–7a and LM–8a in paragraph (c)(3)(ii)(J), and the definitions of the first two variables following Equation LM–10 in paragraph (c)(4)(ii)(A);

v. In the definition of variable ''EF_{SO2}'' for Equation LM–9 in paragraph (c)(4)(i) by revising the reference ''table 1'' to read ''table LM–1'';

w. In paragraph (e)(5) by revising the words ''which have NO_X emission controls of any kind'' to read ''which have add-on NO_X emission controls of any kind (including dry low-NO_X technology)''; and

x. In Table LM–5 that follows paragraph (e) by adding the word ''Other'' before ''Natural Gas'' in the first column of the second entry of the table.

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) * * *

(i) A low mass emissions unit is an affected unit that burns only natural gas or fuel oil (i.e., diesel fuel or residual oil) and for which:

(A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits no more than:

(*1*) 25 tons of SO_2 annually and 50 tons of NO_X annually, for Acid Rain Program affected units (including units which are also subject to the provisions of subpart H of this part),

(*2*) 50 tons of NO_X annually, for units which are subject to the provisions of subpart H of this part and which report emissions data on a year-round basis, in accordance with § 75.74(b), or

(*3*) 25 tons of NO_X per ozone season, for units which are subject to the provisions of subpart H of this part and which report emissions data only during the ozone season, in accordance with § 75.74(b); and

(B) An annual demonstration is provided thereafter, using one of the allowable methodologies in paragraph (c) of this section, showing that the low mass emission unit continues to emit no more than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section.

(ii) Any qualifying unit must start using the low mass emissions excepted methodology as follows:

(A) For a unit that reports emission data on a year-round basis, begin using the methodology in the first unit operating hour in the calendar year in which the unit (as indicated in the certification application) will first qualify as a low mass emissions unit; or

(B) For a unit that is subject to subpart H of this part and that reports only during the ozone season according to § 75.74(c), begin using the methodology in the first unit operating hour in the ozone season in which the unit (as indicated in the certification application) will first qualify as a low mass emissions unit.

(2) * * *

(i) If the designated representative submits a certification application to use the low mass emissions excepted methodology and the Administrator (or permitting authority) certifies the use of such methodology. The certification application shall be submitted no later than 45 days prior to the date on which use of the low mass emissions excepted methodology will commence. The certification application must contain, as applicable, the information in paragraph (a)(2)(i)(A), (a)(2)(i)(B), or (a)(2)(i)(C) of this section.

(A) *Acid Rain Program affected units.* For affected units under the Acid Rain Program (including units which are also subject to the provisions of subpart H of this part), the certification application shall contain:

(*1*) Actual SO_2 and NO_X mass emissions data for each of the three calendar years prior to the calendar year in which the unit will first qualify as a low mass emissions unit, demonstrating to the satisfaction of the Administrator that the unit emits no more than 25 tons of SO_2 and no more than 50 tons of NO_X annually; and

(*2*) Calculated SO_2 and NO_X mass emissions, for each of the three calendar years prior to the calendar year in which the unit will first qualify as a low mass emissions unit, demonstrating to the satisfaction of the Administrator that the unit emits no more than 25 tons of SO_2 and no more than 50 tons of NO_X annually. The calculated emissions for each year shall be determined using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate emission rate from paragraph (c)(1)(i) of this section for SO_2 and paragraph (c)(1)(ii) or (c)(1)(iv) of this section for NO_X.

(B) *Non-Acid Rain subpart H units reporting on a year-round basis.* For units that are not affected under the Acid Rain Program, but are subject to the provisions of subpart H of this part, and which report emissions data on a year-round basis, the certification application shall contain:

(*1*) Actual NO_X mass emissions data for each of the three calendar years prior to the calendar year in which the unit will first qualify as a low mass emissions unit, demonstrating to the satisfaction of the Administrator (or the permitting authority if subpart H is used under a State approved SIP) that the unit emits no more than 50 tons of NO_X annually; and

(*2*) Calculated NO_X mass emissions, for each of the three calendar years prior to the calendar year in which the unit will first qualify as a low mass emissions unit, demonstrating to the satisfaction of the Administrator that the unit emits no more than 50 tons of NO_X annually. The calculated emissions for each year shall be determined using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate NO_X emission rate from paragraph (c)(1)(ii) or (c)(1)(iv) of this section.

(C) *Non-Acid Rain subpart H units, reporting ozone season data only.* For units that are not affected under the Acid Rain Program, but are subject to the provisions of subpart H of this part, and which report emissions data only during the ozone season, the certification application shall contain:

(*1*) Actual NO_X mass emissions data for each of the three ozone seasons prior to the ozone season in which the unit will first qualify as a low mass emissions unit, demonstrating to the satisfaction of the Administrator (or the permitting authority if subpart H is used under a State approved SIP) that the unit emits no more than 25 tons of NO_X per ozone season; and

(*2*) Calculated NO_X mass emissions, for each of the three ozone seasons prior to the ozone season in which the unit will first qualify as a low mass emissions unit, demonstrating to the satisfaction of the Administrator that the unit emits no more than 25 tons of NO_X per ozone season. The calculated emissions for each ozone season shall be determined using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate NO_X emission rate from paragraph (c)(1)(ii) or (c)(1)(iv) of this section.

(ii) When the three full years (or, if applicable, three full ozone seasons) of actual, historical SO_2 and/or NO_X mass emissions data required under paragraph (a)(2)(i) of this section are not available, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of historical SO_2 and NO_X mass emissions data and projected SO_2 and/or NO_X mass emissions, totaling three years (or ozone seasons). Historical data must be used for any years (or ozone seasons) in which historical data exists and projected data should be used for any remaining future years (or ozone seasons). For example, if an Acid Rain Program unit commenced operation two years ago, the designated representative may submit actual, historical data for the previous two years and one year of projected emissions for the current calendar year or, for a new (or newly-affected) unit for which no actual historical data are available, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual (or ozone season) emissions must demonstrate to the satisfaction of the Administrator that the unit will emit less than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section. Projected emissions shall be calculated using either the default emission rates in tables LM–1, LM–2, and LM–3 of this section, or, for NO_X emission rate, a fuel-and-unit-specific NO_X emission rate determined in accordance with the testing procedures in paragraph (c)(1)(iv) of this section, in conjunction with projections of unit operating hours or fuel type and fuel usage, according to one of the allowable calculation methodologies in paragraph (c) of this section.

(b) * * *

(1) Once a low mass emission unit has qualified for and has started using the low mass emissions excepted methodology, an annual demonstration is required, showing that the unit continues to emit no more than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section. The calculation methodology used for the annual demonstration shall be the same methodology, from paragraph (c) of this section, by which the unit initially qualified to use the low mass emissions excepted methodology. The annual demonstration will be based upon the emissions data which the Administrator used to determine whether the unit held sufficient allowances for the calendar year or ozone season.

(2) If any low mass emission unit fails to provide the required annual demonstration under paragraph (b)(1) of this section, such that the calculated cumulative emissions for the unit exceed the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section at the end of any calendar year or ozone season, then:

(i) The low mass emission unit shall be disqualified from using the low mass emissions excepted methodology as of December 31 of the following calendar year (for sources that report emission data on a year-round basis) or as of December 31 of the calendar year in which the unit exceeds the number of tons of NO_X specified in paragraph (a)(1)(i)(A)(*3*) of this section (for sources that report emission data only during the ozone season); and

(ii) The owner or operator of the low mass emission unit shall install, certify, and report SO_2 (Acid Rain Program units only), NO_X, and CO_2 (Acid Rain Program units only) emissions from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13 by December 31 of the year after the unit exceeded the number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A)(*1*) or paragraph (a)(1)(i)(A)(*2*) of this section (for sources that report emission data on a year-round basis) or by May 1 of the year after the unit exceeds the number of tons of NO_X specified in paragraph (a)(1)(i)(A)(*3*) of this section (for sources that report emission data only during the ozone season). If the required monitoring systems have not been installed and certified by the applicable deadline, the owner or operator shall report the following values for each unit operating hour, beginning with the first operating hour after the deadline and continuing until the monitoring systems have been provisionally certified: the maximum hourly heat input for the unit, as defined in § 72.2 of this chapter; the SO_2 emissions, in lb/hr, calculated using the applicable default SO_2 emission rate in Table LM–1 in this section and the maximum hourly unit heat input; the CO_2 emissions, in tons/hr, calculated using the applicable default CO_2 emission rate in Table LM–3 in this section and the maximum hourly unit heat input; and the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(3) If a low mass emission unit that initially qualifies to use the low mass emissions excepted methodology under this section changes fuels, such that a fuel other than those allowed for use in the low mass emissions methodology (i.e., natural gas, diesel fuel, or residual oil) is combusted in the unit, the unit shall be disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. The owner or operator shall install, certify, and report SO_2 (Acid Rain Program units only), NO_X, and CO_2 (Acid Rain Program units only) from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13 prior to a change to such fuel. If the required monitoring systems are not installed and certified prior to the fuel switch, the owner or operator shall report (as applicable) the maximum potential concentration of SO_2, CO_2 and NO_X, the maximum potential NO_X emission rate, the maximum potential flowrate, the maximum potential hourly heat input and the maximum (or minimum, if appropriate) potential moisture percentage, from the date and hour of the fuel switch until the monitoring systems are certified or until probationary calibration error tests of the monitors are passed and the conditional data validation procedures in § 75.20(b)(3) begin to be used. All maximum and minimum potential values shall be specific to the new fuel and shall be determined in a manner consistent with section 2 of appendix A to this part and § 72.2 of this chapter. The owner or operator must notify the Administrator (or the permitting authority) in the case where a unit switches fuels without previously having installed and certified a SO_2,

NO_X and CO_2 monitoring system meeting the requirements of §§ 75.11, 75.12, and 75.13.

* * * * *

(c) * * *

(1) * * *

(iv) * * *

(A) Except as otherwise provided in this paragraph or in paragraphs (c)(1)(iv)(F) and (G) of this section, determine a fuel-and-unit-specific NO_X emission rate by conducting a four load NO_X emission rate test procedure as specified in section 2.1 of appendix E to this part, for each type of fuel combusted in the unit. For a group of units sharing a common fuel supply, the appendix E testing must be performed on each individual unit in the group, unless some or all of the units in the group belong to an identical group of units, as defined in paragraph (c)(1)(iv)(B) of this section, in which case, representative testing may be conducted on units in the identical group of units, as described in paragraph (c)(1)(iv)(B) of this section. For a unit or group of identical units that qualify under § 75.19(c)(1)(iv)(I), single load testing is allowed in lieu of the four load testing. For the purposes of this section, make the following modifications to the appendix E test procedures:

(*1*) Do not measure the heat input as required under section 2.1.3 of appendix E to this part.

(*2*) Do not plot the test results as specified under section 2.1.6 of appendix E to this part.

(*3*) When using method 20 for turbines do not correct the NO_X concentration to 15 percent O_2.

(*4*) If the test is performed on an uncontrolled diffusion flame turbine (i.e., any turbine not using dry low NO_X lean premixed combustion technology or any turbine without steam or water injection) a correction to the observed average NO_X concentration from each run of the Method 20 test must be applied using the following equation:

$$NOx_{corr} = NOx_{obs}\left(\frac{P_r}{P_o}\right)^{0.5} e^{19(H_o - H_r)}\left(\frac{T_r}{T_a}\right)^{1.53} \qquad (\text{Eq. LM}-1\text{a})$$

Where:

$NO_{X_{corr}}$ = Corrected NO_X concentration (ppm).

$NO_{X_{obs}}$ = Average measured NO_X concentration for each run of the Method 20 test (ppm).

P_r = Average annual atmospheric pressure (or average ozone season atmospheric pressure for a subpart H unit that reports data only during the ozone season) at the nearest weather station (e.g., a standardized NOAA weather station located at the airport) for the year (or ozone season) prior to the year of the test (in Hg).

P_o = Observed atmospheric pressure during the test run (in Hg).

H_r = Average annual atmospheric humidity ratio (or average ozone season humidity ratio for a subpart H unit that reports data only during the ozone season) at the nearest weather station, for the year (or ozone season) prior to the year of the test (lb moisture/lb air).

H_o = Observed humidity ratio during the test run (lb moisture/lb air).

T_r = Average annual atmospheric temperature (or average ozone season atmospheric temperature for a subpart H unit that reports data only during the ozone season) at the nearest weather station, for the year (or ozone season) prior to the year of the test (°R).

T_a = Observed atmospheric temperature during the test run (°R).

(B) * * *

* * * * *

(C) Based on the results of the part 75 appendix E testing, determine the fuel-and-unit-specific NO_X emission rate as follows:

(*1*) If a four-load test is performed for an individual low mass emission unit with no NO_X emissions controls of any kind or for a turbine with water injection, steam injection, or water/fuel emulsion and no other type of add-on NO_X controls, the highest three run average NO_X emission rate obtained at any load in the part 75 appendix E test for a particular type of fuel shall be the fuel-and-unit-specific NO_X emission rate, for that type of fuel.

(*2*) [Reserved]

(*3*) If representative four-load testing is performed according to paragraph (c)(1)(iv)(B)(*2*) of this section for a group of identical low mass emission units with no NO_X controls of any kind on any of the units, or for a group of identical turbines with water injection, steam injection, or water/fuel emulsion on all units and no other type of add-on NO_X controls, the fuel-and-unit-specific NO_X emission rate for all units in the group, for a particular type of fuel, shall be the highest three run average NO_X emission rate obtained at any load from any unit tested in the group, for that type of fuel.

(*4*) If a four-load test is performed for an individual low mass emission unit which has add-on NO_X emission controls (except for a turbine that uses water injection, steam injection, or water/fuel emulsion and has no other type of add-on NO_X controls), the fuel-and-unit-specific NO_X emission rate for each type of fuel combusted in the unit shall be the higher of:

(*i*) The highest emission rate from any load of the appendix E test for that type of fuel; or

(*ii*) 0.15 lb/mmBtu.

(*5*) [Reserved]

(*6*) If representative four-load testing is performed according to paragraph (c)(1)(iv)(B)(*2*) of this section for a group of identical low mass emission units having identical add-on NO_X controls (except for a group of identical turbines with water injection, steam injection, or water fuel emulsion and no other type of add-on NO_X controls), the fuel-and-unit-specific NO_X emission rate for each unit in the group of units, for a particular type of fuel, shall be the higher of:

(*i*) The highest NO_X emission rate from all appendix E tests of all tested units in the group, for that type of fuel; or

(*ii*) 0.15 lb/mmBtu.

(*7*) If a single-load test is performed according to § 75.19(c)(1)(iv)(I) for an individual low mass emission unit with no NO_X emissions controls of any kind or for a turbine with water injection, steam injection, or water/fuel emulsion and no other type of add-on NO_X controls, the fuel-and-unit-specific NO_X emission rate for a particular type of fuel combusted in the unit shall be either:

(*i*) The three run average NO_X emission rate obtained in the appendix E test for that type of fuel; or

(*ii*) For an uncontrolled turbine which is tested only at base load and which is capable of operating at a higher load or higher internal operating temperature, the three run average NO_X emission rate obtained in the appendix E tests for that type of fuel, multiplied by 1.15.

(*8*) If representative single-load testing is performed according to § 75.19(c)(1)(iv)(I) for a group of identical low mass emission units with no NO_X controls of any kind on any of the units, or an identical group of turbines with water injection, steam injection, or water/fuel emulsion and no other type of add-on NO_X controls, the fuel-and-unit-specific NO_X emission rate for all units in the group, for a particular type of fuel shall be:

(*i*) The highest three run average NO_X emission rate obtained for that type of fuel in any of the appendix E tests; or

(*ii*) For a group of uncontrolled turbines which are tested only at base load and which are capable of operating at a higher peak load or higher internal operating temperature, the highest three run average NO_X emission rate obtained in any of the appendix E tests for that type of fuel, multiplied by 1.15.

* * * * *

(G) Low mass emission units for which at least 3 years of quality-assured NO_X emission rate data from a NO_X-diluent CEMS and corresponding fuel usage data are available may determine fuel-and-unit-specific NO_X emission rates from the actual data using the following procedure. * * * Use the 95th percentile value for each data set as the fuel-and-unit-specific NO_X emission rate, except that for a unit with add-on NO_X emission controls (excluding turbines with water injection, steam injection, or water/fuel emulsion and no other type of add-on NO_X controls), if the 95th percentile value is less than 0.15 lb/mmBtu, a value of 0.15 lb/mmBtu shall be used as the fuel-and-unit-specific NO_X emission rate.

* * * * *

(I) Notwithstanding the requirements in paragraph (c)(1)(iv)(A) of this section, for a unit (or group of identical units) with no NO_X controls of any kind or for a turbine (or group of identical turbines) with water injection, steam injection, water/fuel emulsion, and no other type of add-on NO_X controls, single-load appendix E testing at the normal operating load may be performed instead of a four load test, if the unit has operated (or if all units in the group of identical units have operated) at a single load level for at least 85.0 percent of all operating hours in the previous three years (12 calendar quarters) prior to the calendar quarter of the appendix E test. To determine whether a unit qualifies for single-load testing, proceed as follows. Determine the range of operation of the unit, according to section 6.5.2.1 of appendix A to this part. Divide the range of operation into four equal load bands. For example, if the range of operation extends from 20 MW to 100 MW, the four equal load bands would be: band #1: 20 MW to 40 MW; band #2: 41 MW to 60 MW; band #3: 61 MW to 80 MW; and band #4: 81 to 100 MW. Then, perform a historical load analysis for all unit operating hours in the 12 calendar quarters preceding the quarter of the test. Determine the percentage of the data that fall in each load band. For a unit which is not part of a group of identical units, if 85.0 percent or more of the data fall within one load band, this is the normal load level for the unit and single-load testing may be performed at any point within that load band. For a group of identical units, if each unit in the group meets the 85.0 percent criterion, then representative single-load testing within the normal load band(s) may be performed. For combustion turbines that are operated to produce approximately constant output (in MW) but which use internal operating and exhaust temperatures and not the actual output in MW to control operation of the turbine, the internal operating temperature setpoint may be used as a surrogate for load in demonstrating that the unit qualifies for single-load testing. To qualify for single load testing, the owner or operator must document that the unit has operated within ±10 percent of the setpoint temperature for 85.0 percent of the unit operating hours in the previous 12 calendar quarters. If the setpoint temperature rather than unit load is used to justify single-load testing, the designated representative must certify in the monitoring plan for the unit that this is the manner of operation and must document the setpoint temperature. If the unit normally operates at a base load setpoint temperature but is capable of operating in a higher output peak load when demand requires, then the test must either be performed at peak load or a multiplier of 1.15 shall be used to adjust a base load test result to approximate a peak load test result.

* * * * *

(3) * * *

(i) * * *

(B) * * *

$$HI_{qtr} = \sum_{1}^{n} HI_{hr} \qquad (\text{Eq. LM}-1)$$

Where:

n = Number of unit operating hours in the quarter.

HI_{hr} = Hourly heat input under paragraph (c)(3)(i)(A) of this section (mmBtu).

* * * * *

(D) For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly heat input for the second calendar quarter of the year shall include only the heat input for the months of May and June, and the cumulative ozone season heat input shall be the sum of the quarterly heat input values for the second and third calendar quarters of the year.

(ii) * * *

(E) * * * For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly heat input for the second calendar quarter of the year shall include only the heat input for the months of May and June. * * *

* * * * *

(G) * * * For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the cumulative ozone season heat input shall be the sum of the quarterly heat input values for the second and third calendar quarters of the year.

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

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

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

Where:

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

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

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

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

(I) * * *

(Eq LM–8 for steam output) * * *

Where:

HI_{hr} = Hourly heat input to the unit (mmBtu).

MW_{hr} = Hourly operating load for the unit (MW).

ST_{hr} = Hourly steam load for the unit (klb of steam/hr).

(J) * * *

(Eq LM–8a for steam output) * * *

Where:

HI_{hr} = Hourly heat input to the individual unit (mmBtu).

MW_{hr} = Hourly operating load for the individual unit (MW).

ST_{hr} = Hourly steam load for the individual unit (klb of steam/hr).

$\sum MW_{qtr}$ all-units = Sum of the quarterly operating loads (from Eq. LM–5) for all units in the group (MW).

$\sum ST_{qtr}$ all-units = Sum of the quarterly steam loads (from Eq. LM–6) for all units in the group (klb of steam/hr).

(4) * * *

(ii) * * *

(A) * * *

(Eq LM–10) * * *

W_{NO_X} = Hourly NO_X mass emissions (lbs).

EF_{NO_X} = Either the NO_X emission factor from Table LM–2 of this section or the fuel- and unit-specific NO_X emission rate determined under paragraph (c)(1)(iv) of this section (lb/mmBtu). * * *

* * * * *

(C) * * * For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the ozone season NO_X mass emissions for the unit shall be the sum of the quarterly NO_X mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for the second and third calendar quarters of the year.

* * * * *

15. Section 75.20 is amended by:

a. Revising paragraphs (b)(2), (b)(3)(i), (c)(2)(ii), (c)(2)(iii), (c)(4) introductory text, (c)(4)(i) through (iii), (g)(2), (h)(3), (h)(4) introductory text, (h)(4)(i) and (h)(4)(ii);

b. In the first sentence of paragraph (a) by removing the words '', which includes the automated data acquisition and handling system, and, where applicable, the CO_2 continuous emission monitoring system,'';

c. In the first sentence of paragraph (a)(3) by revising the words ''section for each continuous emission or opacity monitoring system or component thereof,'' to read ''section, each'', removing the words ''or component thereof'' after each of the two additional occurrences of the words ''opacity monitoring system'' in paragraph (a)(3), and adding the word ''conditional'' before the words ''data validation'' in the last sentence;

d. In paragraph (a)(4)(iii) by removing each occurrence of the words ''or component thereof'', by adding the word ''conditional'' immediately before each occurrence of ''data validation'', and by removing the words '', until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests'' that appear at the end of the second sentence;

e. In paragraph (a)(4)(iv) by removing the words ''or component thereof,'';

f. In the first sentence of paragraph (a)(5)(i) by removing the words ''or component thereof'' and by adding the words ''(or, if the conditional data validation procedures in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section are used, until a probationary calibration error test is passed following corrective actions in accordance with paragraph (b)(3)(ii) of this section)'' after the words ''successfully completed'';

g. In paragraphs (b)(3)(iv)(A), (b)(3)(iv)(B), and (b)(3)(vii)(A) by revising each occurrence of the word ''consecutive'' to read ''cumulative'';

h. Revising the third and fourth sentences of paragraph (b)(5);

i. Removing the second paragraph labeled (c)(1)(v) and paragraph (h)(4)(iii);

j. Adding new paragraphs (c)(2)(iv) and (h)(5);

k. In paragraph (d)(2)(iii) by removing the words ''or SO_2-diluent'' in the third sentence and by adding the word ''cumulative'' after ''168'' in the fifth sentence;

l. In paragraph (d)(2)(v) by adding the words ''(or 720 hours in any ozone season, for sources that report emission data only during the ozone season, in accordance with § 75.74(c))'' after the words ''one calendar year'' in the first sentence and by adding the words ''(or ozone season, as applicable)'' after the words ''per calendar year'' in the second sentence;

m. In the third sentence of (d)(2)(vii) by adding the words '', beginning with the letters ''LK'' (e.g., ''LK1,'' ''LK2,'' etc.)'' after the words ''replacement analyzer'' and by adding the word ''shall'' before the word ''specify'';

n. Adding a sentence to the end of paragraph (g)(1)(i);

o. In paragraph (g)(5) by adding the words ''(or recertified)'' after the word ''certified'' in the first sentence, adding the words ''or for disapproval of a recertification request'' and ''or denial of a recertification request'' after, respectively, the first and second occurrence of the words ''loss of certification'' in the second sentence, removing the word ''either'' from the second sentence, adding the words ''(or recertified)'' after the word ''certified'' in the final sentence; and

p. In the last sentence of paragraph (h)(1) by adding the word ''acceptable'' before the word ''water-to-fuel''.

The revisions and additions read as follows:

§ 75.20 Initial certification and recertification procedures.

* * * * *

(b) * * *

(2) *Notification of recertification test dates.* The owner, operator or designated representative shall submit notice of testing dates for recertification under this paragraph as specified in § 75.61(a)(1)(ii).

(3) * * *

(i) The owner or operator shall either use substitute data, according to the standard missing data procedures in §§ 75.33 through 75.37, or shall report emission data using a reference method or another monitoring system that has been certified or approved for use under this part, in the period extending from the hour of the replacement, modification or change made to a monitoring system that triggers the need to perform recertification testing until the hour of successful completion of all of the required recertification tests. Alternatively, if conditional data validation is used, as provided in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section, the owner or operator shall either use substitute data or shall report data from a certified CEMS or reference method, beginning with the hour of the replacement, modification, or change made to the monitoring system until the hour in which a probationary calibration error test (according to paragraph (b)(3)(ii) of this section) is passed. Notwithstanding this requirement, if the replacement, modification, or change requiring recertification of the CEMS is such that the historical data stream is no longer representative (e.g., where the SO_2 concentration and stack flow rate change significantly after installation of a wet scrubber), the owner or operator shall substitute for missing data as follows, in lieu of using the standard missing data procedures in §§ 75.33 through 75.37: for a change that results in a significantly higher concentration or flow rate, substitute maximum potential values according to the procedures in paragraph (a)(5) of this section; or for a change that results in a significantly lower concentration or flow rate, substitute data using the standard missing data procedures. The owner or operator shall then use the initial missing data procedures in § 75.31, beginning with the first hour of quality assured data obtained with the recertified monitoring system, unless otherwise provided by § 75.34 for units with add-on emission controls. The first hour of quality-assured data for the recertified monitoring system shall either be the hour after all recertification tests have been completed or, if conditional data validation is used, the first quality-assured hour shall be determined in accordance with paragraphs (b)(3)(ii) through (b)(3)(ix) of this section.

* * * * *

(5) *Approval or disapproval of request for recertification.* * * * In the event that a recertification application is disapproved, data from the monitoring system are invalidated and the applicable missing data procedures in §§ 75.31 or 75.33 shall be used from the date and hour of receipt of the disapproval notice back to the hour of the adjustment or change to the CEMS that triggered the need for recertification testing or, if the conditional data validation procedures in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section were used, back to the hour of the probationary calibration error test that began the recertification test period. Data from the monitoring system remain invalid until all required recertification tests have been passed or until a subsequent probationary calibration error test is passed, beginning a new recertification test period. * * *

(c) * * *

(2) * * *

(ii) Relative accuracy test audits, as follows:

(A) For a flow monitor installed on a peaking unit or bypass stack, a single-load RATA at the normal load level, as defined in section 6.5.2.1(d) of appendix A to this part; or

(B) For all other flow monitors, a RATA at each of the three load levels (or operational levels) corresponding to the three flue gas velocities described in section 6.5.2(a) of appendix A to this part;

(iii) A bias test for the single-load flow RATA described in paragraph (c)(2)(ii)(A) of this section; and

(iv) A bias test (or bias tests) for the 3-level flow RATA described in paragraph (c)(2)(ii)(B) of this section, at the following load or operational level(s):

(A) At each load level designated as normal under section 6.5.2.1(d) of appendix A to this part, for units that produce electrical or thermal output; or

(B) At the operational level identified as normal in section 6.5.2.1(d) of appendix A to this part, for units that do not produce electrical or thermal output.

* * * * *

(4) For each CO_2 pollutant concentration monitor, each CO_2 monitoring system that uses an O_2 monitor to determine CO_2 concentration, and each diluent gas monitor used only to monitor heat input rate:

(i) A 7-day calibration error test;

(ii) A linearity check;

(iii) A relative accuracy test audit, where, for an O_2 monitor used to determine CO_2 concentration, the CO_2 reference method shall be used for the RATA; and

* * * * *

(g) * * *

(1) * * *

(i) * * * For orifice, nozzle, and venturi-type flowmeters, the results of primary element visual inspections and/or calibrations of the transmitters or transducers shall also be provided.

* * * * *

(2) *Initial certification, recertification, and QA testing notification.* The designated representative shall provide initial certification testing notification, recertification testing notification, and routine periodic retesting notification for an excepted monitoring system under appendix E to this part as specified in § 75.61. Initial certification testing notification, recertification testing notification, or periodic quality assurance testing notification is not required for an excepted monitoring system under appendix D to this part.

* * * * *

(h) * * *

* * * * *

(3) *Approval of certification applications.* The provisions for the certification application formal approval process in the introductory text of paragraph (a)(4) and in paragraphs (a)(4)(i), (ii), and (iv) of this section shall apply, except that ''continuous emission or opacity monitoring system'' shall be replaced with ''low mass emissions excepted methodology.'' Provisional certification status for the low mass emissions methodology begins when a complete certification application is received, and the methodology is considered to be certified either upon receipt of a written approval notice from the Administrator or, if such notice is not provided, at the end of the Administrator's 120 day review period. However, in contrast to CEM systems or appendix D and E monitoring systems, a provisionally certified or certified low mass emissions excepted methodology may not be used to report data under the Acid Rain Program or in a NO_X mass emissions reduction program under subpart H of this part prior to the applicable commencement date specified in § 75.19(a)(1)(ii).

(4) *Disapproval of low mass emissions unit certification applications.* If the Administrator determines that the certification application for a low mass emissions unit does not demonstrate that the unit meets the requirements of §§ 75.19(a) and (b), the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification is invalidated by the Administrator, and any emission data reported using the excepted methodology during the Administrator's 120-day review period shall be considered invalid. The owner or operator shall use the following

procedures when a certification application is disapproved:

(i) The owner or operator shall substitute the following values, as applicable, for each hour of unit operation in which data were reported using the low mass emissions methodology until such time, date, and hour as continuous emission monitoring systems or excepted monitoring systems, where applicable, are installed and provisionally certified: the maximum potential concentration of SO_2, as defined in section 2.1.1.1 of appendix A to this part; the maximum potential fuel flowrate, as defined in section 2.4.2 of appendix D to this part; the maximum potential values of fuel sulfur content, GCV, and density (if applicable) in Table D–6 of appendix D 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; or the maximum potential CO_2 concentration as defined in section 2.1.3.1 of appendix A to this part. For a unit subject to a State or federal NO_X mass reduction program where the owner or operator intends to monitor NO_X mass emissions with a NO_X pollutant concentration monitor and a flow monitoring system, substitute for NO_X concentration using the maximum potential concentration of NO_X, as defined in section 2.1.2.1 of appendix A to this part, and substitute for volumetric flow using the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part; and

(ii) The designated representative shall submit a notification of certification test dates for the required monitoring systems, as specified in § 75.61(a)(1)(ii), and shall submit a certification application according to the procedures in paragraph (a)(2) of this section.

(5) *Recertification.* Recertification of an approved low mass emissions excepted methodology is not required. Once the Administrator has approved the methodology for use, the owner or operator is subject to the on-going qualification and disqualification procedures in § 75.19(b)(1), on an annual basis.

§ 75.21 [Amended].

16. Section 75.21 is amended by:

a. In paragraph (a)(7) by adding the words ''only for infrequent, non-routine operation (e.g.,'' after the words ''higher sulfur fuel(s)'' in the first sentence, by adding a closing parenthesis after the words ''short-term testing'' in the first sentence, and by revising in the last sentence the words ''720 unit (or stack) operating hour grace period'' to read ''grace period of 720 cumulative unit or stack operating hours'';

b. In paragraph (a)(8) by removing the words ''On and after April 1, 2000'' and by capitalizing the initial occurrence of the word ''the'';

c. In paragraph (a)(9) by revising in the first sentence the words ''exempted under paragraphs (a)(6) or (a)(7) of this section from the SO_2 RATA requirements of this part'' to read ''exempted from the SO_2 RATA requirements of this part under paragraphs (a)(6) or (a)(7) of this section'', and by revising in the last sentence the words ''720 unit (or stack) operating hour grace period'' to read ''grace period of 720 cumulative unit or stack operating hours''; and

d. In paragraph (e)(2) by removing the word ''another''.

17. Section 75.22 is amended by:

a. Removing the last sentence of paragraph (a) introductory text;

b. In the last sentence of paragraph (a)(4) by revising the word ''techniques'' to read ''wet bulb-dry bulb technique''; and

c. Adding a sentence to the end of paragraph (a)(5).

The revisions and additions read as follows:

§ 75.22 Reference test methods.

(a) * * *

(5) * * * Alternatively, Method 20 may be used as the reference method for relative accuracy test audits of NO_X CEMS installed on combustion turbines.

* * * * *

18. Section 75.24 is amended by:

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

b. In paragraph (c)(2) by removing the words ''or certified portable monitor or''.

The revisions read as follows:

§ 75.24 Out-of-control periods and adjustment for system bias.

(a) * * *

(1) For daily calibration error tests, an out-of-control period occurs when the calibration error of a pollutant concentration monitor exceeds the applicable specification in section 2.1.4 of appendix B to this part.

* * * * *

19. Section 75.30 is amended by:

a. In paragraph (a)(6) by removing the period at the end of the paragraph and replacing it with ''; or'';

b. Adding new paragraphs (a)(7) and (a)(8);

c. In the first sentence of paragraph (b) by adding the words ''percent moisture,'' after the words ''flow rate,''; and

d. In paragraphs (d)(1) and (d)(2) by removing the words ''§ 75.54(b)(5) or'' and the words ''as applicable,''.

The revisions and additions read as follows:

§ 75.30 General provisions.

(a) * * *

(7) A valid, quality-assured hour of moisture data (in percent H_2O) has not been measured or recorded for an affected unit, either by a certified moisture monitoring system or an approved alternative monitoring method under subpart E of this part. This requirement does not apply when a default percent moisture value, as provided in §§ 75.11(b) or 75.12(b), is used to account for the hourly moisture content of the stack gas; or

(8) A valid, quality-assured hour of heat input rate data (in mmBtu/hr) has not been measured and recorded for a unit from a certified flow monitor and a certified diluent (CO_2 or O_2) monitor or by an approved alternative monitoring system under subpart E of this part.

* * * * *

20. Section 75.31 is amended by:

a. Revising the first sentence of paragraph (a);

b. Revising paragraphs (c) introductory text and (c)(1);

c. Adding a new sentence to the beginning of paragraph (c)(2);

d. In paragraph (c)(3) by adding the words ''(or for non-load-based units using operational bins, when no prior quality-assured data exist in the corresponding operational bin)'' after the words ''higher load range''; and

e. Adding a new paragraph (d).

The revisions and additions read as follows:

§ 75.31 Initial missing data procedures.

(a) During the first 720 quality-assured monitor operating hours following initial certification of the required SO_2, CO_2, O_2 or moisture monitoring system(s) at a particular unit or stack location (i.e., the date and time at which quality assured data begins to be recorded by CEMS(s) installed at that location), and during the first 2,160 quality-assured monitor operating hours following initial certification of the required NO_X-diluent, NO_X concentration, or flow monitoring system(s) at the unit or stack location, the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section. * * *

* * * * *

(c) *Volumetric flow and NO_X emission rate or NO_X concentration data (load ranges or operational bins used).* The procedures in this paragraph apply to affected units for which load-based ranges or non-load-based operational bins, as defined, respectively, in sections 2 and 3 of appendix C to this part are used to provide substitute NO_X and flow rate data. For each hour of missing volumetric flow rate data, NO_X emission rate data, or NO_X concentration data used to determine NO_X mass emissions:

(1) Whenever prior quality-assured data exist in the load range (or operational bin) corresponding to the operating load (or operating conditions) at the time of the missing data period, the owner or operator shall substitute, by means of the automated data acquisition and handling system, for each hour of missing data, the arithmetic average of all of the prior quality-assured hourly flow rates, NO_X emission rates, or NO_X concentrations in the corresponding load range (or operational bin) as determined using the procedure in appendix C to this part. When non-load-based operational bins are used, if essential operating or parametric data are unavailable for any hour in the missing data period, such that the operational bin cannot be determined, the owner or operator shall, for that hour, substitute (as applicable) the maximum potential flow rate as specified in section 2.1.4.1 of appendix A to this part or the maximum potential NO_X emission rate or the maximum potential NO_X concentration as specified in section 2.1.2.1 of appendix A to this part.

(2) This paragraph (c)(2) does not apply to non-load-based units using operational bins. * * *

* * * * *

(d) *Non-load-based volumetric flow and NO_X emission rate or NO_X concentration data (operational bins not used).* The procedures in this paragraph apply only to affected units that do not produce electrical output (in megawatts) or thermal output (in klb/hr of steam) and for which operational bins are not used. For each hour of missing volumetric flow rate data, NO_X emission rate data, or NO_X concentration data used to determine NO_X mass emissions:

(1) Whenever prior quality-assured data exist at the time of the missing data period, the owner or operator shall substitute, by means of the automated data acquisition and handling system, for each hour of missing data, the arithmetic average of all of the prior quality-assured hourly average flow rates or NO_X emission rates or NO_X concentrations.

(2) Whenever no prior quality-assured flow rate, NO_X emission rate, or NO_X concentration data exist, the owner or operator shall, as applicable, substitute for each hour of missing data, the maximum potential flow rate as specified in section 2.1.4.1 of appendix A to this part or the maximum potential NO_X emission rate or the maximum potential NO_X concentration as specified in section 2.1.2.1 of appendix A to this part.

21. Section 75.32 is amended by:

a. Revising paragraph (a) introductory text;

b. In paragraph (a)(1) by adding the words ''or stack'' after the word ''unit'' and revising the word ''equation'' to read ''Equation''; and

c. Revising paragraph (a)(2) and the first three sentences of paragraph (a)(3).

The revisions and additions read as follows:

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

(a) Following initial certification of the required SO_2, CO_2, O_2 or moisture monitoring system(s) at a particular unit or stack location (i.e., the date and time at which quality assured data begins to be recorded by CEMS(s) at that location), the owner or operator shall, upon completion of the first 720 quality-assured monitor operating hours, calculate and record, by means of the automated data acquisition and handling system, the percent monitor data availability for the SO_2 pollutant concentration monitor, the CO_2 pollutant concentration monitor, the O_2 or CO_2 diluent monitor used to calculate heat input, and the moisture monitoring system (as applicable). Similarly, following initial certification of the required NO_X-diluent, NO_X concentration, or flow monitoring system(s) at a unit or stack location, the owner or operator shall, upon completion of the first 2,160 quality-assured monitor operating hours, calculate and record, by means of the automated data acquisition and handling system, the percent monitor data availability for the flow monitor, the NO_X-diluent monitoring system, and the NO_X concentration monitoring system (as applicable). Notwithstanding these requirements, if three years (26,280 clock hours) have elapsed since the date and hour of initial certification and fewer than 720 (or 2,160, as applicable) quality-assured monitor operating hours have been recorded, the owner or operator shall begin calculating and recording the percent monitor data availability. The percent monitor data availability shall be calculated for each monitored parameter at each unit or stack location, as follows:

* * * * *

(2) Upon completion of 8,760 unit or stack operating hours following initial certification and thereafter, the owner or operator shall, for the purpose of applying the standard missing data procedures of § 75.33, use Equation 9 to calculate, hourly, percent monitor data availability. Notwithstanding this requirement, if three years (26,280 clock hours) have elapsed since initial certification and fewer than 8,760 unit or stack operating hours have been accumulated, the owner or operator shall begin using a modified version of Equation 9, as described in paragraph (a)(3) of this section.

$$\begin{matrix}\text{Percent} \\ \text{monitor data} \\ \text{availability}\end{matrix} = \frac{\begin{matrix}\text{Total unit operating hours} \\ \text{for which quality-assured data} \\ \text{were recorded during previous} \\ \text{8,760 unit operating hours}\end{matrix}}{8{,}760} \times 100 \qquad \text{(Eq. 9)}$$

(3) When calculating percent monitor data availability using Equation 8 or 9, the owner or operator shall include all unit operating hours, and all monitor operating hours for which quality-assured data were recorded by a certified primary monitor; a certified redundant or non-redundant backup monitor or a reference method for that unit; or by an approved alternative monitoring system under subpart E of this part. No hours from more than three years (26,280 clock hours) earlier shall be used in Equation 9. For a unit that has accumulated fewer than 8,760 unit or stack operating hours in the previous three years (26,280 clock hours), use the words ''in the previous three years'' instead of ''during previous 8,760 unit or stack operating hours'' in Equation 9, and use ''total unit or stack operating

hours in the previous three years'' instead of ''8,760.'' * * *

* * * * *

22. Section 75.33 is amended by:

a. Revising paragraphs (a) and (c) introductory text;

b. Adding paragraphs (b)(5), (b)(6), (b)(7), (c)(7), (c)(8), (c)(9), (c)(10), (d), and (e);

c. In paragraphs (c)(1) introductory text and (c)(2) introductory text by removing the words ''or continuous emission monitoring system'';

d. In paragraphs (c)(1)(i), (c)(1)(ii)(A), (c)(2)(i), (c)(2)(ii)(A), and (c)(3) by adding the words ''or operational bin'' after each occurrence of the words ''unit load range'';

e. In paragraph (c)(3) by removing the words ''section 2 of'';

f. In paragraph (c)(4) by adding a sentence to the end of the paragraph;

g. In paragraph (c)(5) by adding a new first sentence and by adding the words ''recording during the previous 2,160 quality-assured monitor operating hours'' before the words ''at the next'';

h. In paragraph (c)(6) by revising the words ''or a higher load range'' to read ''(or a higher load range) or for the corresponding operational bin''; and

i. Redesignating Tables 1 and 2 from paragraph to follow paragraph (c)(9) and revising them.

The revisions and additions read as follows:

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

(a) Following initial certification of the required SO_2, NO_X, and flow rate monitoring system(s) at a particular unit or stack location (i.e., the date and time at which quality assured data begins to be recorded by CEMS(s) at that location) and upon completion of the first 720 quality-assured monitor operating hours (for SO_2) or the first 2,160 quality assured monitor operating hours (for flow, NO_X emission rate, or NO_X concentration), the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section and depicted in Table 1 (SO_2) and Table 2 of this section (NO_X, flow). Notwithstanding these requirements, if three years (26,280 clock hours) have elapsed since the date and hour of initial certification, and fewer than 720 (or 2,160, as applicable) quality assured monitor operating hours have been recorded, the owner or operator shall begin using the missing data procedures of this section. The owner or operator of a unit shall substitute for missing data using quality-assured monitor operating hours of data from no earlier than three years (26,280 clock hours) prior to the date and time of the missing data period.

(b) * * *

(5) The owner or operator may, for units that combust more than one type of fuel, elect to implement the missing data routines in paragraphs (b)(1) through (b)(4) of this section on a fuel-specific basis. If this option is selected, the owner or operator shall document this in the monitoring plan required under § 75.53. To implement this option, the owner or operator shall create and maintain a separate SO_2 concentration database for each type of fuel (or blend), in order to obtain the appropriate substitute data values when that fuel (or blend) is combusted. Also, for the purposes of providing substitute data under paragraph (b)(4) of this section, a separate, fuel-specific maximum potential SO_2 concentration (MPC) value shall be determined for each type of fuel (or blend) combusted in the unit, in a manner consistent with section 2.1.1.1 of appendix A to this part. For fuel that qualifies as pipeline natural gas or natural gas (as defined in § 72.2 of this chapter), the owner or operator shall, for the purposes of determining the MPC, either determine the maximum total sulfur content and minimum gross calorific value (GCV) of the gas by fuel sampling and analysis or shall use a default total sulfur content of 0.05 percent by weight (dry basis) and a default GCV value of 950 Btu/scf. The exact methodology used to determine each fuel-specific MPC value shall be documented in the monitoring plan for the unit or stack.

(6) If the owner or operator elects to switch from non-fuel-specific missing data routines to fuel-specific routines (as described in paragraph (b)(5) of this section) and if, at the time of the change, the initial missing data procedures of § 75.31 have previously been completed on a non-fuel-specific basis and the calculation of percent monitor data availability and use of the standard missing data procedures has begun in accordance with §§ 75.32 and 75.33, the owner or operator need not repeat the initial missing data procedures on a fuel-specific basis. Rather, the calculation of percent monitor data availability may continue uninterrupted, and the fuel-specific SO_2 concentration databases may be created prospectively, beginning at the time of the change. Alternatively, the databases may be created from historical CEM data, if records are available documenting the type of fuel combusted during each quality-assured monitor operating hour. If, at the time of the missing data period, there is at least one, but fewer than 720 quality-assured monitor operating hours of fuel-specific SO_2 concentration data in a particular database, use whatever data are in the database, for the purposes of the lookback periods described in § 75.33, paragraphs (b)(1)(ii)(A), (b)(2)(ii)(A), and (b)(3). If there are no quality-assured monitor operating hours of fuel-specific SO_2 concentration data in a particular database, report the fuel-specific MPC value determined under paragraph (b)(5) of this section for each hour of the missing data period.

(7) Table 1 of this section summarizes the provisions of paragraphs (b)(1) through (b)(6) of this section.

(c) *Volumetric flow rate, NO_X emission rate and NO_X concentration data.* Use the procedures in this paragraph to provide substitute NO_X and flow rate data for all affected units for which load-based ranges have been defined in accordance with section 2 of appendix C to this part. For units that do not produce electrical or thermal output (i.e., non-load-based units), use the procedures in this paragraph only to provide substitute data for volumetric flow rate, and only if operational bins have been defined for the unit, as described in section 3 of appendix C to this part. Otherwise, use the applicable missing data procedures in paragraph (d) or (e) of this section for non-load-based units. For each hour of missing volumetric flow rate data, NO_X emission rate data, or NO_X concentration data used to determine NO_X mass emissions:

* * * * *

(4) * * * In addition, when non-load-based operational bins are used, the owner or operator shall substitute (as applicable) the maximum potential flow rate for any hour in the missing data period in which essential operating or parametric data are unavailable and the operational bin cannot be determined.

(5) This paragraph does not apply to non-load-based affected units using operational bins. * * *

* * * * *

(7) If there are fewer than 2,160 quality-assured monitor operating hours in a load range or operational bin, use whatever data are in the load range or bin for purposes of the lookback periods described in paragraphs (c)(1)(i), (c)(1)(ii)(A), (c)(2)(i), (c)(2)(ii)(A), (c)(3), and (c)(5) of this section.

(8) This paragraph (c) (8) does not apply to affected units using non-load-based operational bins. The owner or operator may, for units that combust more than one type of fuel, elect to implement the missing data routines in paragraphs (c)(1) through (c)(7) of this section on a fuel-specific basis. If this option is selected, the owner or operator

shall document this in the monitoring plan required under § 75.53. To implement this option, the owner or operator shall (as applicable) create and maintain a separate flow rate, NO_X emission rate, or NO_X concentration database for each type of fuel, in order to obtain the appropriate substitute data values when that fuel is combusted. Also, for the purposes of providing substitute data under paragraph (c)(4) of this section, a separate, fuel-specific maximum potential concentration (MPC), maximum potential NO_X emission rate (MER), or maximum potential flow rate (MPF) value (as applicable) shall be determined for each type of fuel combusted in the unit, in a manner consistent with section 2.1.2.1 or 2.1.4.1 of appendix A to this part. The exact methodology used to determine each fuel-specific MPC, MPF, or MER value shall be documented in the monitoring plan for the unit or stack.

(9) This paragraph (c)(9) does not apply to affected units using non-load-based operational bins. If the owner or operator elects to switch from non-fuel-specific missing data routines to fuel-specific routines (as described in paragraph (b)(8) of this section) and if, at the time of the change, the initial missing data procedures of § 75.31 have previously been completed on a non-fuel-specific basis and the calculation of percent monitor data availability and use of the standard missing data procedures has begun in accordance with §§ 75.32 and 75.33, the owner or operator need not repeat the initial missing data procedures on a fuel-specific basis. Rather, the calculation of percent monitor data availability may continue uninterrupted, and the fuel-specific NO_X or flow rate databases may be created prospectively, beginning at the time of the change. Alternatively, the databases may be created from historical CEM data, if records are available documenting the type of fuel combusted during each quality-assured monitor operating hour. If, at the time of the missing data period, there is at least one, but fewer than 2,160 quality-assured monitor operating hours of fuel-specific NO_X or flow rate data in a particular load range, use whatever data are in the load range, for the purposes of the lookback periods described in paragraphs (c)(1)(i), (c)(1)(ii)(A), (c)(2)(i), (c)(2)(ii)(A), and (c)(3) of this section. If there are no quality-assured monitor operating hours of fuel-specific NO_X or flow rate data in a particular load range (or a higher range), report the appropriate fuel-specific maximum potential value determined under paragraph (c)(2)(ii)(B)(*8*) of this section. Tables 1 and 2 follow:

TABLE 1.—MISSING DATA PROCEDURE FOR SO_2 CEMS, CO_2 CEMS, MOISTURE 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	N ≤ 24	Average	[y] HB/HA
	N > 24	For SO_2, CO_2, and H_2O**, the greater of	
		Average	HB/HA.
		90th percentile [1]	*720 hours.
		For O_2 and H_2O[x], the lesser of	
		Average	HB/HA.
		10th percentile	*720 hours.
90 or more, but below 95	N ≤ 8	Average	[y] HB/HA
	N > 8	For SO_2, CO_2, and H_2O**, the greater of:.	
		Average	HB/HA.
		95th percentile [1]	*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	N > 0	For SO_2, CO_2, and H_2O**, Maximum value [1]	*720 hours.
		For O_2 and H_2O[x]: Minimum value [1]	*720 hours.
Below 80	N > 0	Maximum potential concentration [3] or % (for SO_2, CO_2, 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 (or ozone seasons) prior to the missing data period.

[1] For units with add-on SO_2 emission controls, the owner or operator may maintain separate databases of controlled and uncontrolled emissions and provide substitute data from the appropriate database according to whether the add-on controls are documented to be operating properly during the missing data period.

[2] During unit operating hours.

[3] For units with add-on SO_2 controls, you may (if available) report the SO_2 concentration from a certified inlet monitor, in lieu of reporting the MPC.

[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.

[y] For units with add-on SO_2 controls, if the missing data procedures of § 75.34(a)(2) are used, report the maximum SO_2 concentration in the previous 720 quality-assured monitor operating hours in the uncontrolled database in lieu of HB/HA average value, for each missing data hour in which the add-on controls are not documented to be operating properly.

TABLE 2.—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 (in hours)	Load ranges
95 or more	$N \leq 24$	Average	2160	Yes.
	$N > 24$	The greater of:		
		Average	HB/HA	No.
		90th percentile	*2160	Yes.
90 or more, but below 95	$N \leq 8$	Average	*2160	Yes.
	$N > 8$	The greater of:		
		Average	HB/HA	No.
		95th percentile	*2160	Yes.
80 or more, but below 90	$N > 0$	Maximum value [1]	*2160	Yes.
Below 80	$N > 0$	Maximum NO_X emission rate; 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, in the corresponding load range (''load bin'') for each hour of the missing data period. May be either fuel-specific or non-fuel-specific. If there are < 2,160 hours of data in the load bin, use all data in the bin for the lookback. 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 (or ozone seasons) prior to the missing data period.

[1] For units with add-on NO_X emission controls, the owner or operator may maintain separate databases of controlled and uncontrolled emissions and provide substitute data from the appropriate database according to whether the add-on controls are documented to be operating properly during the missing data period.

[2] During unit operating hours.

[3] For units with add-on NO_X controls, you may report the NO_X concentration from a certified inlet monitor (if available) in lieu of reporting the MPC.

(10) The load-based provisions of paragraphs (c)(1) through (c)(9) of this section are summarized in Table 2 of this section. The non-load-based provisions for volumetric flow rate, found in paragraphs (c)(1) through (c)(4), (c)(6), and (c)(7) of this section, are presented in Table 4 of this section.

(d) *Non-load-based NO_X emission rate and NO_X concentration data.* Use the procedures in this paragraph to provide substitute NO_X data for affected units that do not produce electrical output (in megawatts) or thermal output (in klb/hr of steam). For each hour of missing NO_X emission rate data, or NO_X concentration data used to determine NO_X mass emissions:

(1) Whenever the monitor data availability is equal to or greater than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(i) For a missing data period less than or equal to 24 hours, substitute, as applicable, for each missing hour, the arithmetic average of the NO_X emission rates or NO_X concentrations recorded by a monitoring system in a 2,160 hour lookback period. The lookback period may be comprised of either:

(A) The previous 2,160 quality assured monitor operating hours, or

(B) The previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins, as defined in section 3 of appendix C to this part, are used.

(ii) For a missing data period greater than 24 hours, substitute, as applicable, for each missing hour, the greater of:

(A) The 90th percentile NO_X emission rate or the 90th percentile NO_X concentration recorded by a monitoring system during the previous 2,160 quality assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used), or

(B) The arithmetic average of the hourly NO_X emission rates or NO_X concentrations recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used).

(2) Whenever the monitor data availability is at least 90.0 percent but less than 95.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period according to the following procedures:

(i) For a missing data period of less than or equal to eight hours, substitute, as applicable, the arithmetic average of the hourly NO_X emission rates or NO_X concentrations recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used).

(ii) For a missing data period greater than eight hours, substitute, as applicable, for each missing hour, the greater of:

(A) The 95th percentile hourly flow rate or the 95th percentile NO_X emission rate or the 95th percentile NO_X concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used), or

(B) The arithmetic average of the hourly NO_X emission rates or NO_X concentrations recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used).

(3) Whenever the monitor data availability is at least 80.0 percent but less than 90.0 percent, the owner or operator shall, by means of the automated data acquisition and handling system, substitute, as applicable, for each hour of each missing data period, the maximum hourly NO_X emission rate or the maximum hourly NO_X concentration

recorded during the previous 2,160 quality-assured monitor operating hours (or during the previous 2,160 quality-assured monitor operating hours at the corresponding operational bin, if operational bins are used).

(4) Whenever the monitor data availability is less than 80.0 percent, the owner or operator shall substitute, as applicable, for each hour of each missing data period, the maximum NO_X emission rate, as defined in section 2.1.2.1 of appendix A to this part, or the maximum potential NO_X concentration, as defined in section 2.1.2.1 of appendix A to this part. In addition, when operational bins are used, the owner or operator shall substitute (as applicable) the maximum potential NO_X emission rate or the maximum potential NO_X concentration for any hour in the missing data period in which essential operating or parametric data are unavailable and the operational bin cannot be determined.

(5) If operational bins are used and no prior quality-assured NO_X concentration data or NO_X emission rate data exist for the corresponding operational bin, the owner or operator shall substitute, as applicable, either the maximum potential NO_X emission rate or the maximum potential NO_X concentration, as defined in section 2.1.2.1 of appendix A to this part.

(6) If operational bins are used and there is at least one, but fewer than 2,160 quality-assured monitor operating hours of NO_X emission rate or NO_X concentration data in a particular operational bin, use whatever data are in the bin, for the purposes of the lookback periods described in paragraphs (d)(1)(i)(B), (d)(1)(ii)(A), (d)(1)(ii)(B), (d)(2)(i), (d)(2)(ii)(A), (d)(2)(ii)(B), and (d)(3) of this section.

(7) Table 3 of this section summarizes the provisions of paragraphs (d)(1) through (d)(6) of this section.

(e) *Non-load-based volumetric flow rate data.* (1) If operational bins, as defined in section 3 of appendix C to this part, are used for a non-load-based unit, use the missing data procedures in paragraph (c) of this section to provide substitute volumetric flow rate data for the unit.

(2) If operational bins are not used for a non-load-based unit, modify the procedures in paragraph (c) of this section as follows:

(i) In paragraphs (c)(1) through (c)(3), the words ''previous 2,160 quality-assured monitor operating hours'' shall apply rather than ''previous 2,160 quality-assured monitor operating hours at the corresponding unit load range or operational bin, as determined using the procedure in appendix C to this part;''

(ii) The last sentence in paragraph (c)(4) does not apply;

(iii) Paragraphs (c)(5), (c)(7), (c)(8), and (c)(9) are not applicable; and

(iv) In paragraph (c)(6), the words, ''for either the corresponding load range (or a higher load range) or for the corresponding operational bin'' do not apply.

(3) Table 4 of this section summarizes the provisions of paragraphs (e)(1) and (e)(2) of this section. Tables 3 and 4 follow:

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 (in hours)
95 or more	N≤24	Average	*2160
		The greater of:	
	N>24	Average	*2160
		90th percentile	*2160
90 or more, but below 95	N≤8	Average	*2160
	N>8	The greater of:	
		Average	*2160
		95th percentile	*2160
80 or more, but below 90	N>0	Maximum value	*2160
Below 80, or operational bin indeterminable	N>0	Maximum NO_X emission rate or maximum potential NO_X concentration.	None

*If operational bins are used, the lookback period is 2,160 quality-assured, monitor operating hours in the corresponding operational bin. If there are < 2,160 hours of data in the operational bin, use all data in the bin for the lookback. If operational bins are not used, the lookback period is the previous 2,160 quality-assured monitor operating hours. For units for which data are reported 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 (or ozone seasons) prior to the missing data period.

[1] During unit operating hours.

TABLE 4.—NON-LOAD-BASED MISSING DATA PROCEDURE FOR FLOW RATE CEMS

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) [1]	Method	Lookback period (in hours)
95 or more	N≤24	Average	*2160
	N>24	The greater of:	
		Average	HB/HA
		90th percentile	*2160

TABLE 4.—NON-LOAD-BASED MISSING DATA PROCEDURE FOR FLOW RATE CEMS—Continued

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours) [1]	Method	Lookback period (in hours)
90 or more, but below 95	$N \leq 8$	Average	*2160
	$N > 8$	The greater of:	
		Average	HB/HA.
		95th percentile	*2160
80 or more, but below 90	$N > 0$	Maximum value	*2160
Below 80, or operational bin indeterminable	$N > 0$	Maximum potential flow rate	None

*If operational bins are used, the lookback period is the previous 2,160 quality-assured, monitor operating hours in the corresponding operational bin. If there are < 2,160 hours of data in the operational bin, use all data in the bin for the lookback. 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 (or ozone seasons) prior to the missing data period.

[1] During unit operating hours.

23. Section 75.34 is amended by:

a. Revising paragraphs (a) introductory text, (a)(1), (a)(2), and (d);

b. Redesignating paragraph (a)(3) as (a)(4) and adding new paragraph (a)(3);

c. In the second sentence of newly redesignated paragraph (a)(4) by removing the words ''§ 75.55(b) or'' and '', as applicable''; and

d. In paragraph (c) by revising the word '' NO_{X2}'' to read '' NO_X''.

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 (including turbines that use dry low-NO_X (DLN) technology) shall use one of the following options for each hour in which quality-assured data from the outlet SO_2 and/or NO_X monitoring system(s) are not obtained, and shall document which option is selected in the monitoring plan required under § 75.53:

*(1) The owner or operator may use the missing data substitution procedures specified in §§ 75.31 through 75.33 to provide substitute data for any missing data hour(s) in which the add-on emission 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, for each missing data period, record parametric data to verify the proper operation of the SO_2 or NO_X add-on emission controls during each hour, as described in paragraph (d) of this section. For any missing data hour(s) in which such parametric data are either not provided or, if provided, do not demonstrate that proper operation of the SO_2 or NO_X add-on emission controls has been maintained, the owner or operator shall substitute (as applicable) the maximum potential NO_X concentration (MPC) as defined in section 2.1.2.1 of appendix A to this part, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter, or the maximum potential concentration for SO_2, as defined by section 2.1.1.1. Alternatively, for SO_2 or NO_X, the owner or operator may substitute, if available, the hourly SO_2 or NO_X concentration recorded by a certified inlet monitor, in lieu of the MPC. For each hour in which data from an inlet monitor are reported, the owner or operator shall use a method of determination code (MODC) of ''22'' (see Table 4a in § 75.57). In addition, under § 75.64(c), the designated representative shall submit as part of each electronic quarterly report, a certification statement, verifying the proper operation of the SO_2 or NO_X add-on emission control for each missing data period in which the missing data procedures of §§ 75.31 through 75.33 were applied; or

(2) The owner or operator may use the missing data procedures in §§ 75.31 through 75.33 for all missing data hours if:

(i) For purposes of the data lookback periods described in § 75.33, two separate historical databases are created and maintained. The first (controlled) database shall consist of quality-assured monitor operating hours of SO_2 concentration, NO_X concentration, or NO_X emission rate (as applicable) recorded downstream of the add-on emission controls, when the add-on controls are in operation (i.e., on). For a unit with more than one type of add-on controls (e.g., a unit with steam injection and SCR), the emission data for any hour(s) in which any of the add-on controls are operating shall be included in the controlled database. The second (uncontrolled) database shall consist of quality-assured monitor operating hours of SO_2 concentration, NO_X concentration, or NO_X emission rate (as applicable) recorded when none of the add-on emission controls are in operation (i.e., off). Alternatively, the uncontrolled database may consist of quality-assured monitor operating hours of data recorded by a certified monitoring system located at the control device inlet or by a certified monitoring system installed on a bypass stack (for exhaust configurations in which the flue gases are occasionally routed through an auxiliary stack, bypassing the add-on emission controls);

(ii) For each hour of each missing data period, when the appropriate mathematical algorithm from Table 1 or Table 2 in § 75.33 requires a lookback for the 90th percentile value, or the 95th percentile value, or the maximum value from the previous 720 (or 2,160) quality-assured monitor operating hours, the value is obtained from the appropriate database (i.e., from the controlled database if the add-on controls are documented to be operating properly during the hour or from the uncontrolled database if the add-on controls are either not in operation or not documented to be operating properly during the hour). To provide the necessary documentation, the owner or operator shall, for each missing data period, record parametric data, as described in paragraph (d) of this section;

(iii) For SO_2, when substitution of the average of the hour-before and hour-after values is required under §§ 75.33(b)(1)(i) or (b)(2)(i), the maximum SO_2 concentration recorded in the previous 720 quality-assured monitoring hours in the uncontrolled database is substituted in lieu of the hour-before and hour-after value, for each hour of the missing data period in which the add-on controls are either not in operation or are not documented to be operating properly;

(iv) When the percent monitor data availability (calculated according to § 75.32) is <80 percent, the maximum potential SO_2 or NO_X concentration or the maximum potential NO_X emission rate (as applicable) is substituted for each hour of the missing data period, in accordance with § 75.33(b)(4) and (c)(4); and

(v) The designated representative, in accordance with § 75.64(c), submits as part of each electronic quarterly report a certification statement verifying the proper operation of the SO_2 or NO_X add-on emission controls during each missing data hour in which substitute data values from the first (controlled) database are reported, and (if applicable) for SO_2, during each missing data hour in which the average of the hour before and hour after values is reported.

(3) If the owner or operator elects to switch from the missing data option in paragraph (a)(1) of this section to the option in paragraph (a)(2) of this section, and if, at the time of the change, the initial missing data procedures in § 75.31 have been previously completed and use of the standard missing data procedures of § 75.33 has begun, the owner or operator need not repeat the initial missing data procedures. Rather, calculation of the percent monitor data availability may continue uninterrupted and the two databases (controlled and uncontrolled) may be created prospectively, beginning at the time of the change. Alternatively, the databases may be created from historical CEM data, if records are available documenting the operational status (i.e., on or off) of the emission controls during each quality-assured monitor operating hour. If, at the time of the missing data period, there are no quality-assured monitor operating hours of SO_2 or NO_X data in the appropriate database for the lookback periods described in § 75.33(b)(1)(ii)(A), (b)(2)(ii)(A), (b)(3), (c)(1)(i), (c)(1)(i)(A), (c)(2)(i), (c)(2)(ii)(A), and (c)(3), report the appropriate maximum potential SO_2 or NO_X concentration or the maximum potential NO_X emission rate (as applicable) for each hour of the missing data period. If there is at least one, but fewer than the requisite number of quality-assured monitor operating hours of SO_2 or NO_X data in the appropriate database for the lookback periods (i.e., either 720 or 2,160 hours, as applicable) the owner or operator shall use all available data in the database for the lookbacks.

* * * * *

(d) In order to implement the option in paragraphs (a)(1) and (a)(2) of this section, the owner or operator shall keep records of information as described in § 75.58(b)(3)(i) to verify the proper operation of all add-on SO_2 or NO_X emission controls (including dry low-NO_X technology), during all periods of SO_2 or NO_X emission missing data. The owner or operator shall document in the quality assurance/quality control (QA/QC) program required by section 1 of appendix B to this part, the parameters monitored and (as applicable) the ranges and combinations of parameters that indicate proper operation of the controls. If any of the following control methods are used: wet or dry limestone scrubbing, limestone injection, steam or water injection, selective catalytic or non-catalytic reduction (i.e., SCR or SNCR), or any other control method involving injection of water, steam, or chemical reagents into the combustion chamber or flue gas stream, at least one key parameter directly related to the control device removal efficiency shall be monitored. Examples of such key parameters include the water-to-fuel ratio, the ammonia injection rate, and the slurry flow rate. Irrespective of which specific parameter(s) are monitored, a demonstrable correlation between the parametric data and control device removal efficiency shall be established, as part of the QA/QC program. The correlation shall be based on parametric data recorded during unit operation, with the add-on controls in-service and the SO_2 or NO_X monitor (as applicable) at the control device outlet providing quality-assured data. EPA recommends that the correlation be based on a minimum of 720 hours of such data, obtained at various load levels, covering the range of operation of the unit. The correlation shall serve as the basis for determining whether to use substitute data values from the controlled database or from the uncontrolled database, during periods of missing SO_2 or NO_X data. The owner or operator shall provide the information recorded under § 75.58(b)(3) and the related QA/QC program information to the Administrator, to the EPA Regional Office, or to an auditor from EPA or from the appropriate State or local agency, upon request.

24. Section 75.35 is revised to read as follows:

§ 75.35 Missing data procedures for CO_2.

(a) The owner or operator of a unit with a CO_2 continuous emission monitoring system for determining CO_2 mass emissions in accordance with § 75.10 (or an O_2 monitor that is used to determine CO_2 concentration in accordance with appendix F to this part) shall substitute for missing CO_2 pollutant concentration data using the procedures of paragraphs (b) and (d) of this section.

(b) During the first 720 quality assured monitor operating hours following initial certification at a particular unit or stack location (i.e., the date and time at which quality assured data begins to be recorded by a CEMS at that location), or (when implementing these procedures for a previously certified CO_2 monitoring system) during the 720 quality assured monitor operating hours preceding implementation of the standard missing data procedures in paragraph (d) of this section, the owner or operator shall provide substitute CO_2 pollutant concentration data according to the procedures in § 75.31(b).

(c) [Reserved]

(d) Upon completion of 720 quality assured monitor operating hours using the initial missing data procedures of § 75.31(b), the owner or operator shall provide substitute data for CO_2 concentration data or substitute CO_2 data for heat input determination, as applicable, in accordance with the procedures in § 75.33(b) except that the term ''CO_2 concentration'' shall apply rather than ''SO_2 concentration,'' the term ''CO_2 pollutant concentration monitor'' or ''CO_2 diluent monitor'' shall apply rather than ''SO_2 pollutant concentration monitor,'' and the term ''maximum potential CO_2 concentration, as defined in section 2.1.3.1 of appendix A to this part'' shall apply, rather than ''maximum potential SO_2 concentration.''

25. Section 75.36 is amended by:

a. Revising the section heading;

b. In paragraph (a) by adding the word ''rate'' after the words ''hourly heat input'' in the first sentence, by adding the word ''rate'' after the words ''heat input'' in the second and third sentences, removing the words ''On and after April 1, 2000,'' in the third sentence and capitalizing ''When'' to begin that sentence, and by removing the last sentence;

c. Revising paragraph (b);

d. Removing and reserving paragraph (c); and

e. In paragraph (d) by adding the word ''rate'' after each occurrence of the word ''input''.

The revisions and additions read as follows:

§ 75.36 Missing data procedures for heat input rate determinations.

* * * * *

(b) During the first 720 quality assured monitor operating hours following initial certification at a particular unit or stack location (i.e., the date and time at which quality assured data begins to be recorded by a CEMS at that location), or (when implementing these procedures for a previously certified CO_2 or O_2 monitor) during the 720 quality assured monitor operating hours preceding implementation of the standard missing data procedures in paragraph (d) of this section, the owner or operator shall provide substitute CO_2 or O_2 data, as applicable, for the calculation of heat input (under section 5.2 of appendix F to this part) according to § 75.31(b).

* * * * *

26. Section 75.37 is amended by:

a. In paragraph (a) by revising the words ''On and after April 1, 2000, the'' to read ''The'' in the first sentence and by removing the second sentence;

b. Revising paragraphs (c) and (d)(2)(i); and

c. In paragraph (d) introductory text by removing the words ''of the moisture monitoring system''.

The revisions and additions read as follows:

§ 75.37 Missing data procedures for moisture.

* * * * *

(c) During the first 720 quality assured monitor operating hours following initial certification at a particular unit or stack location (i.e., the date and time at which quality assured data begins to be recorded by a moisture monitoring system at that location), the owner or operator shall provide substitute data for moisture according to § 75.31(b).

(d) * * *

(2) * * *

(i) Provided that none of the following equations is used to determine SO_2 emissions, CO_2 emissions or heat input: Equation F–2, F–14b, F–16, F–17, or F–18 in appendix F to this part, or Equation 19–5 or 19–9 in Method 19 in appendix A to part 60 of this chapter, use the missing data procedures in § 75.33(b), except that the term ''moisture percentage'' shall apply rather than ''SO_2 concentration,'' the term ''moisture monitoring system'' shall apply rather than ''SO_2 pollutant concentration monitor,'' and the term ''maximum potential moisture percentage, as defined in section 2.1.6 of appendix A to this part'' shall apply, rather than ''maximum potential SO_2 concentration;'' or

* * * * *

27. Section 75.41 is amended by adding the words ''(Eq. 22)'' immediately before ''where,'' in paragraph (b)(2)(v)(B) and by revising Equation 27 in paragraph (c)(2)(ii) to read as follows:

§ 75.41 Precision criteria.

* * * * *

(c) * * *

(2) * * *

(ii) * * *

$$r = \frac{\sum e_p e_v - \left(\sum e_p\right)\left(\sum e_v\right)/n}{\left(\left[\sum e_p^2 - \left(\sum e_p\right)^{2/n}\right]\left[\sum e_v^2 - \left(\sum e_v\right)^{2/n}\right]\right)^{(1/2)}} \quad \text{(Eq. 27)}$$

28. Section 75.53 is amended by:

a. Removing and reserving paragraphs (c) and (d);

b. Revising paragraphs (a)(1), (e)(1)(viii), (f)(1)(i)(F), and (f)(2)(i)(H);

c. In paragraph (b) by adding the words '', by the applicable deadline specified in § 75.62 or elsewhere in this part'' prior to the period at the end of the paragraph;

d. In paragraph (e)(1)(i)(D) by adding the words ''emergency/startup'' after the words ''primary/secondary'';

e. In paragraph (e)(1)(i)(E) by adding the words ''primary/secondary controls indicator;'' after the words ''(if applicable);'';

f. In paragraph (e)(1)(ix) by revising the words ''Part 75 monitoring'' to read ''Monitoring'', adding the words ''ARP/Subpart H facility ORISPL number,'' after the words ''boiler identification number,'', and adding the words ''(or equivalent)'' after the words ''reporting indicator'';

g. In paragraph (f)(2)(i)(F) by adding the word ''rate'' after the word ''input'' and the word ''emission'' after the word '' NO_X'';

h. Adding a sentence to the end of paragraph (f)(5)(i); and

i. Adding paragraphs (f)(5)(i)(A) through (H).

The revisions and additions read as follows:

§ 75.53 Monitoring plan.

(a) * * *

(1) The owner or operator shall meet the requirements of paragraphs (a), (b), (e), and (f) of this section.

* * * * *

(e) * * *

(1) * * *

(viii) Stack exit height (ft) above ground level and ground level elevation above sea level.

* * * * *

(f) * * *

(1) * * *

(i) * * *

(F) The method used to demonstrate that the unit qualifies for monthly GCV sampling or daily fuel sampling for sulfur content, if applicable.

* * * * *

(2) * * *

(i) * * *

(H) To document the unit qualifies as a peaking unit, current calendar year or ozone season, capacity factor data as specified in the definition of peaking unit in § 72.2 of this chapter, and an indication of whether the data are actual, projected, or operating data.

* * * * *

(5) * * *

(i) * * * The following items should be included:

(A) Current calendar year of application;

(B) Type of qualification;

(C) Years one, two, and three;

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

(E) Annual or ozone season NO_X mass calculated from emission factors for years one, two, and three;

(F) Annual measured or projected SO_2 mass emissions for years one, two, and three;

(G) Annual SO_2 mass calculated from emission factors for years one, two, and three; and

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

* * * * *

§ 75.54 [Reserved]

29. Section 75.54 is removed and reserved.

§ 75.55 [Reserved]

30. Section 75.55 is removed and reserved.

§ 75.56 [Reserved]

31. Section 75.56 is removed and reserved.

32. Section 75.57 is amended by:

a. Revising the introductory paragraph;

b. In paragraph (a)(3) by removing the words ''§ 75.55 or'' and ''as applicable,'';

c. In paragraph (a)(4) by removing both occurrences of the words ''§ 75.56 or'';

d. Revising Table 4a at the end of paragraph (c)(4);

e. Revising paragraph (d)(6); and

f. Revising the first sentence of paragraph (d)(7).

The revisions read as follows:

§ 75.57 General recordkeeping provisions.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

* * * * *

(c) * * *

(4) * * *

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 SO2 and/or NO_X emission controls: SO2 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	Average of the hourly SO_2 concentration, CO_2 concentration, O_2 concentration, NO_X concentration, moisture percentage, flow rate, or NO_X emission rate for the hour before and the hour following a missing data period, using initial missing data procedures.
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 (or, if applicable, a higher load range), for the applicable lookback period, using the initial missing data procedures.
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 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	[Reserved].
14	Diluent cap value (if the cap is replacing a CO_2 measurement, use 5.0 percent for boilers and 1.0 percent for turbines; if it is replacing an O_2 measurement, use 14.0 percent for boilers and 19.0 percent for turbines).
15	[Reserved].
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 or NO_X emission rate or flow rate, for an hour in which flue gases are discharged through an unmonitored bypass stack.
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.)
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.

(d) * * *

(6) Hourly average NO_X emission rate (for NO_X-diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth);

(7) Hourly average NO_X emission rate (for NO_X-diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in § 75.24(d). * * *

* * * * *

33. Section 75.58 is amended by:

a. Revising the introductory paragraph;

b. In paragraphs (b)(1)(i) and (c) by removing the words ''§ 75.54(c) or'';

c. In paragraph (b)(1)(xi) and (b)(2)(vii) by removing the words ''Codes 1–15 in Table 4 of § 75.54 or'';

d. Revising paragraph (b)(3);

e. Adding a period to the end of paragraph (c)(7)(ii);

f. In paragraph (d) by removing the words ''paragraph 75.54(d) or'';

g. In paragraph (e)(1) by removing the words ''§§ 75.54(c)(1) and (c)(3) or''; and

h. In paragraph (f) by removing the words ''§§ 75.54(b) through (e) or''.

The revisions read as follows:

§ 75.58 General recordkeeping provisions for specific situations.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

* * * * *

(b) * * *

(3) For units with add-on SO_2 or NO_X emission controls following the provisions of § 75.34(a)(1) or (a)(2), the owner or operator shall record:

(i) Parametric data which demonstrate, for each hour of missing SO_2 or NO_X emission data, the proper operation of the add-on emission controls, as described in the quality assurance/quality control program for the unit. The parametric data shall be maintained on site and shall be submitted, upon request, to the Administrator, EPA Regional office, State, or local agency;

(ii) A flag indicating, for each hour of missing SO_2 or NO_X emission data, either that the add-on emission controls are operating properly, as described in the quality assurance/quality control program, or that the add-on emission controls are not operating properly; and

(iii) For the purposes of creating the controlled and uncontrolled databases described under § 75.34(a)(2), a flag indicating whether the add-on emission controls are operating (on) or not operating (off) during each unit operating hour.

* * * * *

34. Section 75.59 is amended by:

a. Revising the introductory paragraph;

b. Revising paragraphs (a)(1)(vii), (a)(7)(ii)(P) and (a)(7)(iii)(F);

c. In the second sentence of paragraph (a)(7) by adding the words ''of this section'' after the words ''through (a)(7)(vi)'';

d. In paragraph (a)(10)(i)(E) by revising the reference to ''(a)(7)(iii)(A)'' to read ''(a)(7)(iii)'';

e. In paragraph (b)(2)(v) by adding the word ''level'' after the word ''high'';

f. In paragraphs (b)(4)(ii)(K) and (b)(5)(i)(N) by removing the word ''and'' after the semicolon;

g. In paragraph (b)(4)(ii)(L) by removing the period and adding in its place ''; and'';

h. In paragraph (b)(5)(i)(O) by removing the period and adding in its place a semicolon;

i. Adding paragraphs (b)(4)(ii)(M), (b)(5)(i)(P), and (b)(5)(i)(Q);

j. In paragraph (c)(1) by removing the words ''§ 75.55(b) or'';

k. In paragraph (d)(1) by revising the word ''under'' to read ''using the procedures of'';

l. Adding the word ''and'' at the end of paragraph (d)(1)(xi);

m. Removing paragraphs (d)(1)(xiii) through (d)(1)(xvi);

n. Redesignating existing paragraph (d)(2) as (d)(3) and adding a new paragraph (d)(2); and

o. In newly designated paragraph (d)(3)(x) by removing the words ''and (*3*)''.

The revisions and additions read as follows:

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

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

(a) * * *

(1) * * *

(vii) Reference signal or calibration gas level;

* * * * *

(7) * * *

(ii) * * *

(P) Average stack flow rate, adjusted, if applicable, for wall effects (scfh, wet basis);

* * * * *

(iii) * * *

(F) Average velocity differential pressure at traverse point (inches of H_2O) or the average of the square roots of the velocity differential pressures at the traverse point ((inches of $H_2O)^{1/2}$);

* * * * *

(b) * * *

(4) * * *

(ii) * * *

(M) Number of hours excluded due to co-firing.

* * * * *

(5) * * *

(i) * * *

(P) Flag to indicate highest NO_X emission rate for unit-specific, fuel-specific NO_X emission rate testing; and

(Q) Adjusted NO_X default rate (for low mass emission unit default testing).

* * * * *

(d) * * *

(2) For each single-load or four-load appendix E test, record the following:

(i) The three-run average NO_X emission rate for each load level;

(ii) An indicator that the average NO_X emission rate is the highest NO_X average emission rate recorded at any load level of the test (if appropriate);

(iii) The default NO_X emission rate (highest three run average NO_X emission rate at any load level, multiplied by 1.15, if appropriate;

(iv) An indicator that the add-on NO_X emission controls were operating or not operating during each run of the test; and

(v) Parameter data indicating the use and efficacy of control equipment during the test.

* * * * *

35. Section 75.60 is amended by adding paragraph (b)(7) to read as follows:

§ 75.60 General provisions.

* * * * *

(b) * * *

(7) *Routine appendix E retest reports.* If requested by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report within 45 days after completing a required periodic retest according to section 2.2 of appendix E to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by § 75.59(b)(5) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report.

* * * * *

36. Section 75.61 is amended by:

a. In paragraph (a)(1) by removing the words ''and except for testing only of the data acquisition and handling system'' from the end of that paragraph, by adding a period to the end of the first sentence, and by adding two new sentences to the end of the paragraph;

b. In paragraph (a)(1)(i) by revising the number ''45'' to read ''21'';

c. Revising paragraphs (a)(1)(ii) and (a)(1)(iii);

d. In paragraph (a)(1)(iv) by revising both references to ''(a)(1)'' to read ''(a)(1)(ii)'', by adding the words ''or other retests'' to the end of the first sentence, and by adding the words ''(or other retests)'' after the words ''recertification tests'' in the second sentence;

e. In the first sentence of paragraph (a)(2) introductory text by adding the words '', or will become affected,'' after the words ''commercial operation'';

f. In paragraph (a)(4) by removing ''(a)'' after the second and third occurrences of ''§ 75.4'';

g. Revising the first sentence of paragraph (a)(5) introductory text;

h. In paragraph (a)(5)(ii) by adding the words '', appendix E retest, or low mass emissions unit retest'' after the words ''relative accuracy test''; and

i. Revising paragraph (a)(6).

The revisions and additions read as follows:

§ 75.61 Notifications.

(a) * * *

(1) * * * The owner or operator shall also provide written notification of testing performed under § 75.19(c)(1)(iv)(A) to establish fuel and unit-specific NO_X emission rates for low mass emissions units. Such notifications are not required, however, for initial certifications and recertifications of excepted monitoring systems under appendix D to this part.

* * * * *

(ii) *Notification of certification retesting, recertification testing, and retesting of low mass emissions units.* For retesting required following a loss of certification under § 75.20(a)(5), for recertification testing required under § 75.20(b), or for retesting required under § 75.19(c)(1)(iv)(D), notice of the date of any required RATA testing, any required retesting under section 2.3 in appendix E to this part, or any required retesting to determine new fuel and unit-specific NO_X emission rates for low mass emissions units shall be submitted either in writing or by telephone at least 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this paragraph (a)(1)(ii) as long as notice of the new date is provided by telephone or other means at least 7 days prior to the original scheduled test date or the revised test date, whichever is earlier.

(iii) *Repeat of testing without notice.* Notwithstanding the above notice requirements, the owner or operator may elect to repeat a certification or recertification test or low mass emissions unit retest immediately, without advance notification, whenever the owner or operator has determined during the certification or recertification testing or low mass emissions unit retesting that a test was failed or must be aborted, or that a second test is necessary in order to attain a reduced relative accuracy test frequency.

* * * * *

(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, and of periodic retesting of low mass emissions units performed under § 75.19(c)(1)(iv)(D), no later than 21 days prior to the first scheduled day of testing. * * *

* * * * *

(6) *Notice of combustion of emergency fuel under appendix D or E.* The designated representative of an oil-fired unit or gas-fired unit using appendix D or E of this part shall, for each calendar quarter in which emergency fuel is combusted, provide notice of the combustion of the emergency fuel in the cover letter (or electronic equivalent) which transmits the next quarterly report submitted under § 75.64. The notice shall specify the exact dates and hours during which the emergency fuel was combusted.

* * * * *

37. Section 75.62 is amended by:

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

b. In the third sentence of paragraph (a)(2) by adding the words ''certification and'' after the words ''with any'' and the words ''certification or'' after the words ''associated with the''.

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, by a method specified by the Administrator, as follows: no later than 45 days prior to the initial certification tests; at the time of each certification or recertification application submission; in each electronic quarterly report; and whenever an update of the electronic monitoring plan information is required, either under § 75.53(b) or elsewhere in this part (for such required updates, submit the updated electronic monitoring plan within 30 days of the event with which the monitoring plan change is associated, unless otherwise specified in this part).

* * * * *

38. Section 75.63 is amended by:

a. Revising paragraphs (a)(1)(i) and (ii), and removing paragraph (a)(1)(iii);

b. In paragraph (a)(2)(i) by adding the words ''under § 75.20(b)'' after the words ''recertification tests'' and the words ''of this section'' after the words ''paragraph (b)(1)'';

c. Revising the first and second sentences of paragraph (a)(2)(ii);

d. In paragraph (a)(2)(iii) by adding the words ''rather than certification testing'' after the words ''are required'';

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

f. In paragraph (b)(1)(ii) by removing the words ''§ 75.56 or'' and ''as applicable,''; and

g. Revising the first sentence of paragraphs (b)(2)(i) and (c).

The revisions and additions read as follows:

§ 75.63 Initial certification or recertification application.

(a) * * *

(1) * * *

(i) For CEM systems or excepted monitoring systems under appendix D or E to this part, within 45 days after completing all initial certification tests, submit:

(A) To the Administrator, the electronic information required by paragraph (b)(1) of this section and a hardcopy certification application form (EPA form 7610–14). The results of the certification tests shall also be included in the appropriate electronic quarterly report submittal under § 75.64. Except for subpart E applications for alternative monitoring systems or unless specifically requested by the Administrator, do not submit a hardcopy of the test data and results to the Administrator.

(B) To the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency, the hardcopy information required by paragraph (b)(2) of this section.

(ii) For units for which the owner or operator is applying for certification approval of the optional excepted methodology under § 75.19 for low mass emissions units, submit, no later than 45 days prior to commencing use of the methodology:

(A) To the Administrator, the electronic information required by paragraph (b)(1)(i) of this section, and a hardcopy certification application form (EPA form 7610–14); and

(B) To the applicable EPA Regional Office and appropriate State and/or local air pollution control agency, the hardcopy information required by § 75.19(a)(2), the hardcopy results of any appendix E (of this part) tests or any CEMS data analysis used to derive a fuel and unit specific default NO_X emission rate, and the hardcopy information in paragraphs (b)(2)(i), (iii), and (iv) of this section.

(2) * * *

(ii) Within 45 days after completing all recertification tests under § 75.20(b), submit the hardcopy information required by paragraph (b)(2) of this section to the applicable EPA Regional

Office and the appropriate State and/or local air pollution control agency. The applicable EPA Regional Office or appropriate State or local air pollution control agency may waive the requirement to provide hardcopy recertification test data and results. * * *

* * * * *

(b) * * *

(1) * * *

(i) A complete, up-to-date version of the electronic portion of the monitoring plan, according to § 75.53(e) and (f), in the format specified in § 75.62(c).

* * * * *

(2) * * *

(i) Any changed portions of the hardcopy monitoring plan information required under § 75.53(e) and (f). * * *

* * * * *

(c) *Format.* The electronic portion of each certification or recertification application shall be submitted in a format to be specified by the Administrator and by a method specified by the Administrator. * * *

39. Section 75.64 is amended by:

a. Revising the first and third sentences of paragraph (a) introductory text and revising paragraph (a)(2) introductory text;

b. In paragraph (a)(2)(iii) by removing the words ''§ 75.54(f) or'';

c. In paragraph (a)(2)(iv) by removing the words ''§ 75.55(b)(3) or'';

d. In paragraph (a)(2)(vi) by removing the words ''§ 75.54(g) or'';

e. In paragraph (a)(2)(vii) by removing the words ''§ 75.56 or'';

f. In paragraph (a)(2)(viii) by removing the words ''§ 75.56(a)(5)(vii), § 75.56(a)(5)(ix),'';

g. In paragraph (a)(2)(xi) by removing the words ''§ 75.56(a)(7) or'';

h. In paragraph (a)(4) by removing the words ''hundredth prior to April 1, 2000 and to the nearest'' and the words ''on and after April 1, 2000'';

i. Removing and reserving paragraphs (a)(2)(v), (a)(8), and (e);

j. In paragraph (d) by removing the words ''or hardcopy''; and

k. In paragraph (f) by removing the words ''modem and''.

The revisions 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). * * * 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, 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). * * *

* * * * *

(2) The information and hourly data required in § 75.53 and §§ 75.57 through 75.59, excluding the following:

* * * * *

§ 75.65 [Amended].

40. Section 75.65 is amended by removing the words ''§ 75.54(f) or'' and '', as applicable,''.

§ 75.66 [Amended]

41. Section 75.66 is amended by:

a. In paragraph (e) by removing the words ''§ 75.55(b) or'' and '', as applicable,''; and

b. Removing and reserving paragraph (i).

42. Section 75.70 is amended by:

a. Adding a hyphen to the term ''non-affected'' in paragraph (a)(1);

b. In paragraph (d)(1) by adding the words ''in § 75.20'' after the words ''recertification procedures'';

c. Revising paragraphs (e), (f) introductory text, and (f)(1) introductory text;

d. In paragraphs (f)(1)(i), (ii), and (iii) by adding a comma after the word ''valid'' and revising the words ''quality assured'' to read ''quality-assured'';

e. In paragraphs (f)(1)(ii) and (iii) by removing the word ''or'' from the end of each paragraph;

f. In paragraph (f)(1)(iii) by adding the word ''rate'' before the word ''data'', revising the word ''mmBtu'' to read ''mmBtu/hr'', and revising the word ''accepted'' to read ''excepted'';

g. In paragraph (f)(1)(iv) by revising the words ''volumetric flow monitor, and without a diluent monitor'' to read ''flow monitor'', by adding a comma after the reference to ''§ 75.32'', and by removing the period and adding ''; or'' to the end of the paragraph;

h. Adding new paragraph (f)(1)(v);

i. In paragraph (g)(1) by adding the word ''rate'' after the words ''and heat input'';

j. In paragraph (g)(2) by revising the words ''of the unit under section 2.1'' to read '', as defined in section 2.1.4.1''; and

k. Revising paragraph (g)(6).

The revisions and additions read as follows:

§ 75.70 NO_X mass emissions provisions.

* * * * *

(e) *Quality assurance and quality control requirements.* For units that use continuous emission monitoring systems to account for NO_X mass emissions, the owner or operator shall meet the applicable quality assurance and quality control requirements in § 75.21, appendix B to this part, and § 75.74(c) for the NO_X-diluent continuous emission monitoring systems, flow monitoring systems, NO_X concentration monitoring systems, moisture monitoring systems, and diluent monitors required under § 75.71. Units using the low mass emissions excepted methodology under § 75.19 shall meet the applicable quality assurance requirements of that section, except as otherwise provided in § 75.74(c). Units using excepted monitoring methods under appendices D and E to this part shall meet the applicable quality assurance requirements of those appendices.

(f) *Missing data procedures.* Except as provided in § 75.74(c)(7), the owner or operator shall provide substitute data from monitoring systems required under § 75.71 for each affected unit as follows:

(1) For an owner or operator using a continuous emissions monitoring system, substitute for missing data in accordance with the applicable missing data procedures in §§ 75.31 through 75.37 whenever the unit combusts fuel and:

* * * * *

(v) A valid, quality-assured hour of moisture data (in percent H_2O) has not been measured or recorded for an affected unit, either by a certified moisture monitoring system or an approved alternative monitoring method under subpart E of this part. This requirement does not apply when a default percent moisture value, as provided in §§ 75.11(b) or 75.12(b), is used to account for the hourly moisture content of the stack gas.

* * * * *

(g) * * *

(6) For any unit using continuous emissions monitors, the conditional data validation procedures in § 75.20(b)(3)(ii) through (b)(3)(ix).

* * * * *

43. Section 75.71 is amended by:

a. In paragraph (a)(1) by adding the word ''rate'' after the words ''heat input'' and by removing the hyphen after each occurrence of the words ''O_2'' and ''CO_2'';

b. In the second sentence of paragraph (a)(2) by adding the word ''rate'' after the words ''measure heat input'', by removing the word ''use'' after the words ''if applicable,'', and by adding the words ''may be used'' after the words ''appendix D to this part'';

c. In paragraph (b)(1) by revising ''i.e.'' to read ''e.g.'' and by adding the words ''or to calculate the heat input rate'' before the words '', the owner'';

d. In paragraph (b)(3) by adding the word ''rate'' after the word ''input'' and by adding a comma after the word ''maintain'';

e. In the first and second sentences of paragraph (c)(2) by adding the word ''rate'' after the words ''heat input''; and

f. In paragraph (d)(2) by removing the words ''or, if applicable, paragraph (e) of this section'', by revising the reference in ''paragraph (c)'' to read ''paragraph (c)(1) or (c)(2)'', and by adding two new sentences to the end of the paragraph.

The revisions and additions read as follows:

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

* * * * *

(d) * * *

(2) * * * If the required CEMS are not installed and certified by that date, the owner or operator shall report hourly NO_X mass emissions as the product of the maximum potential NO_X emission rate (MER) and the maximum hourly heat input of the unit (as defined in § 72.2 of this chapter), starting with the first unit operating hour after the deadline and continuing until the CEMS are provisionally certified. For each unit operating hour in which the MER is used for NO_X mass reporting, the MER shall be specific to the type of fuel being combusted in the unit.

* * * * *

44. Section 75.72 is amended by:

a. Revising the first sentence of the introductory paragraph to the section;

b. Revising paragraphs (a)(1) introductory text and (a)(1)(i);

c. Redesignating paragraph (a)(1)(ii) as paragraph (a)(1)(iii) and adding a new paragraph (a)(1)(ii);

d. In the newly redesignated paragraph (a)(1)(iii)(A) by adding the word ''rate'' after the words ''heat input'' and by adding the words ''and a diluent monitor'' after the word ''system'' in newly redesignated paragraph (a)(1)(iii)(B);

e. In paragraph (a)(2) introductory text by adding the words '', for purposes of heat input determination,'' after the words ''from each unit and'';

f. In paragraph (a)(2)(ii)(A) by adding the word ''rate'' after the words ''heat input'';

g. In paragraph (b)(1) introductory text by removing the semicolon and adding the words '', for purposes of heat input determination,'' at the end of the paragraph;

h. In paragraph (b)(2)(ii)(B) by adding the word ''rate'' after the words ''heat input'' in the first sentence;

i. In paragraph (b)(2)(iii) by adding the words '', in accordance with paragraph (a) of this section'' after the word ''purposes'';

j. Revising paragraph (c);

k. Revising paragraph (d);

l. In paragraph (e) introductory text by revising the first sentence, adding a new second sentence, and revising the words ''appendix F of '' to read ''appendix F to'' in the third sentence;

m. In paragraph (e)(1) introductory text by revising the second sentence and adding a new third sentence;

n. In paragraph (e)(1)(i) by adding the word ''rate'' after ''heat input'' and by revising the reference to ''§ 75.16(e)(5)'' to read ''§ 75.16(e)(3)'';

o. In paragraph (e)(2) by adding the word ''rate'' after the words ''heat input'' in the first sentence; and

p. In paragraph (g) by removing the words ''the owner or operator should'' and by revising the reference to ''§ 75.16(e)(5)'' to read ''§ 75.16(e)(3)''.

The revisions and additions read as follows:

§ 75.72 Determination of NO_X mass emissions.

Except as provided in paragraphs (e) and (f) of this section, the owner or operator of an affected unit shall 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). * * *

(a) * * *

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system and diluent monitor in the common stack, record the combined NO_X mass emissions for the units exhausting to the common stack, and, for the purposes of determining the hourly unit heat input rates, either:

(i) Apportion the common stack heat input rate to the individual units according to the procedures in § 75.16(e)(3);

(ii) Install, certify, operate, and maintain a flow monitoring system and diluent monitor in the duct to the common stack from each unit; or

* * * * *

(c) *Unit with a main stack and a bypass stack.* Whenever any portion of the flue gases from an affected unit can be routed through a bypass stack to avoid the installed NO_X-diluent continuous emissions monitoring system or NO_X concentration monitoring system, the owner and operator shall either:

(1) Install, certify, operate, and maintain separate NO_X-diluent continuous emissions monitoring systems and flow monitoring systems on the main stack and the bypass stack and calculate NO_X mass emissions for the unit as the sum of the NO_X mass emissions measured at the two stacks;

(2) Monitor NO_X mass emissions at the main stack using a NO_X-diluent CEMS and a flow monitoring system and measure NO_X mass emissions at the bypass stack using the reference methods in § 75.22(b) for NO_X concentration, flow rate, and diluent gas concentration, or NO_X concentration and flow rate, and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems; or

(3) Install, certify, operate, and maintain a NO_X-diluent CEMS and a flow monitoring system only on the main stack. If this option is chosen, it is not necessary to designate the exhaust configuration as a multiple stack configuration in the monitoring plan required under § 75.53, since only the main stack is monitored. For each unit operating hour in which the bypass stack is used, report NO_X mass emissions as follows. If the unit heat input is determined using a flow monitor and a diluent monitor, report NO_X mass emissions using the maximum potential NO_X emission rate, the maximum potential flow rate, and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable). The maximum potential NO_X emission rate shall be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). If the unit heat input is determined using a fuel flowmeter, in accordance with appendix D to this part, report NO_X mass emissions as the product of the fuel-specific maximum potential NO_X emission rate and the actual measured hourly heat input rate.

(d) *Unit with multiple stack or duct configuration.* When the flue gases from an affected unit discharge to the atmosphere through more than one stack, or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X-diluent continuous

emission monitoring system and a flow monitoring system in each of the multiple stacks and determine NO_X mass emissions from the affected unit as the sum of the NO_X mass emissions recorded for each stack. If another unit also exhausts flue gases into one of the monitored stacks, the owner or operator shall comply with the applicable requirements of paragraphs (a) and (b) of this section, in order to properly determine the NO_X mass emissions from the units using that stack;

(2) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system in each of the ducts that feed into the stack, and determine NO_X mass emissions from the affected unit using the sum of the NO_X mass emissions measured at each duct; or

(3) If the unit is eligible to use the procedures in appendix D to this part and if the conditions and restrictions of § 75.17(c)(2) are fully met, install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system in one of the ducts feeding into the stack or in one of the multiple stacks, (as applicable) in accordance with § 75.17(c)(2), and use the procedures in appendix D to this part to determine heat input rate for the unit.

(e) *Units using a NO_X concentration monitoring system and a flow monitoring system to determine NO_X mass.* The owner or operator may use a NO_X concentration monitoring system and a flow monitoring system to determine NO_X mass emissions for the cases described in paragraphs (a) through (c) of this section and in paragraph (d)(1) or paragraph (d)(2) of this section (in place of a NO_X-diluent continuous emissions monitoring system and a flow monitoring system). However, this option may not be used for the case described in paragraph (d)(3) of this section. * * *

(1) * * * In addition, the owner or operator must provide heat input rate values for each unit utilizing a common stack. The owner or operator may either:

* * * * *

45. Section 75.73 is amended by:

a. In the second sentence of paragraph (a) by adding the word ''compliance'' before the word ''deadline'', and by revising the reference to ''§ 75.70'' to read ''§ 75.70(b)'';

b. Revising paragraph (a)(6) introductory text;

c. Adding new paragraphs (a)(8), (a)(9), (d)(6), (f)(1)(vii), and (f)(1)(viii);

d. Revising all of paragraph (c)(3) except for the heading and the first sentence;

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

f. In paragraph (e)(2) by adding the words ''certification or'' before the words ''recertification application'' in the third sentence, and by adding a new sentence to the end of the paragraph.

The revisions and additions read as follows:

§ 75.73 Recordkeeping and reporting.

(a) * * *

(6) *Specific heat input record provisions for gas-fired or oil-fired units using the procedures in appendix D to this part.* In lieu of the information required in § 75.57(c)(2), the owner or operator shall record the information in § 75.58(c) for each affected gas-fired or oil-fired unit and each non-affected gas- or oil-fired unit under § 75.72(b)(2)(ii) for which the owner or operator is using the procedures in appendix D to this part for estimating heat input.

* * * * *

(8) Total NO_X mass emissions for the hour.

(9) Formulas from monitoring plan for total NO_X mass.

* * * * *

(c) * * *

(3) * * * In addition, to the extent applicable, each monitoring plan shall contain the information in § 75.53, paragraphs (f)(1)(i), (f)(2)(i), and (f)(4) in electronic format and the information in § 75.53, paragraphs (f)(1)(ii) and (f)(2)(ii) in hardcopy format. For units using the low mass emissions excepted methodology under § 75.19, the monitoring plan shall include the additional information in § 75.53, paragraphs (f)(5)(i) and (f)(5)(ii). The monitoring plan also shall identify, in electronic format, the reporting schedule for the affected unit (ozone season or quarterly), the beginning and end dates for the reporting schedule, seasonal controls indicator, ozone season fuel switching flag, and whether year-round reporting for the unit is required by a State or local agency.

(d) * * *

(6) *Routine appendix E retest reports.* If requested by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report within 45 days after completing a required periodic retest according to section 2.2 of appendix E to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by § 75.59(b)(5) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report.

(e) * * *

(1) *Electronic submission.* The designated representative for an affected unit shall submit to the Administrator, by a method specified by the Administrator, a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (e)(2) of this section) for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii) to the permitting authority, no later than 45 days prior to the initial certification test; at the time of a certification or recertification application submission; and whenever an update of the electronic monitoring plan is required, either under § 75.53 or elsewhere in this part. Submit the updated electronic monitoring plan within 30 days of the event with which the monitoring plan is associated, unless otherwise specified in this part.

(2) * * * Electronic submittal of all monitoring plan information, including hardcopy portions, is permissible provided that a paper copy of the hardcopy portions can be furnished upon request.

(f) * * *

(1) * * *

(vii) Reporting period heat input.

(viii) New reporting frequency and begin date of the new reporting frequency.

* * * * *

46. Section 75.74 is amended by:

a. Revising paragraph (c)(2)(i)(D)(*1*);

b. Adding a new second sentence to paragraph (c)(2)(ii);

c. In the third sentence of paragraph (c)(2)(ii)(C) by revising the words ''in every period of five consecutive calendar'' to read ''every five'';

d. Revising paragraph (c)(2)(ii)(H)(*1*);

e. Revising the second sentence of paragraph (c)(3)(iii);

f. In the second sentence of paragraph (c)(3)(iv) by adding the words ''the cumulative'' after the word ''only'' and by revising the words ''included when determining'' to read ''used to determine'';

g. In paragraph (c)(3)(v) by adding a new second sentence;

h. In paragraph (c)(3)(vi)(B) by removing the quotation marks around the words ''probationary calibration error test'' in the first sentence, by revising the reference to ''§ 75.20(b)(3)'' to read ''§ 75.20(b)(3)(ii)'' in the first sentence, and by adding the words ''(subject to the restrictions in paragraph (c)(3)(xii) of this section)'' after the words ''§ 75.20(b)(3)'' in the third sentence;

i. In paragraph (c)(3)(viii) by adding the word ''cumulative'' after the number ''168'';

j. In paragraph (c)(3)(x) by adding the words '', if applicable,'' after the words ''§ 75.20(b)(3) and'';

k. In paragraph (c)(3)(xi) by adding a comma after each occurrence of the word ''diagnostic'', by revising the words ''§ 75.31 or § 75.33'' in the third sentence to read ''§ 75.31, § 75.33, or § 75.37'', and by adding the words ''conditional data validation'' before the word ''provisions'' in the fifth sentence;

l. In paragraphs (c)(3)(xii)(A) and (B) by revising each occurrence of the words ''§ 75.31 or § 75.33'' to read ''§ 75.31, § 75.33, or § 75.37'', by adding a comma after the occurrence of the word ''diagnostic'' in each paragraph, and by adding the words ''conditional data validation'' before the word ''provisions'' in the second sentence of paragraph (c)(3)(xii)(B).

m. In paragraph (c)(4) by adding the word ''rate'' after the words ''heat input'' in the first sentence and by adding a new third sentence;

n. In paragraph (c)(5) by adding the word ''rate'' after the words ''heat input'';

o. Revising paragraphs (c)(6)(v), (c)(7)(ii), and (c)(8)(ii);

p. Adding a new paragraph (c)(7)(iii);

q. In the second sentence of paragraph (c)(10)(ii) by revising the word ''monitoring'' to read ''monitored''; and

r. In the second sentence of paragraph (c)(11) by revising the word ''calender'' to read ''calendar''.

The revisions and additions read as follows:

§ 75.74 Annual and ozone season monitoring and reporting requirements.

* * * * *

(c) * * *

(2) * * *

(i) * * *

(D) * * *

(*1*) If the monitor passed a linearity check on or after January 1 of the previous year and the unit or stack on which the monitor is located operated for fewer than 336 cumulative unit or stack operating hours (as defined in § 72.2 of this chapter) in the previous ozone season, the owner or operator may have a grace period of up to 168 cumulative unit or stack operating hours to perform a linearity check, subject to the restrictions in this paragraph and in paragraph (c)(3)(xii) of this section, and the owner or operator may continue to submit quality assured data from that monitor as long as all other required quality assurance tests are passed. If the unit or stack operates for more than the allowable grace period of 168 cumulative operating hours in the current ozone season without a linearity check of the monitor having been performed, the owner or operator of the unit shall either report data from a certified backup monitoring system or reference method or shall report substitute data using the missing data procedures under paragraph (c)(7) of this section, starting with the first unit or stack operating hour after the grace period expires and continuing until the successful completion of a linearity check. Note that the grace period shall not extend beyond the end of the third calendar quarter.

* * * * *

(ii) * * * Notwithstanding this requirement, a pre-ozone season RATA need not be performed between October 1 and April 30, if a RATA was passed during the previous ozone season and if the conditions in paragraph (a)(3)(vii) of this section are met, thereby ensuring that the data from the CEMS are quality-assured at the beginning of the current ozone season.

* * * * *

(H) * * *

(*1*) If the monitoring system passed a RATA on or after January 1 of the previous year and the unit or stack on which the monitor is located operated for fewer than 336 cumulative unit or stack operating hours (as defined in § 72.2 of this chapter) in the previous ozone season, the owner or operator may have a grace period of up to 720 cumulative unit or stack operating hours to perform a RATA, subject to the restrictions in this paragraph and in paragraph (c)(3)(xii) of this section, and the owner or operator may continue to report quality assured data from that monitor as long as all other required quality assurance tests are passed. If the unit or stack operates for more than the allowable grace period of 720 cumulative unit or stack operating hours in the current ozone season, without a RATA of the monitoring system having been performed, the owner or operator of the unit or stack shall either report data from a certified backup monitoring system or reference method or shall report substitute data using the missing data procedures under paragraph (c)(7) of this section, starting with the first unit operating hour after the grace period expires and continuing until the successful completion of the RATA. Note that the grace period shall not extend beyond the end of the third calendar quarter.

* * * * *

(3) * * *

(iii) * * * If the flow-to-load ratio test for the second calendar quarter is failed, the owner or operator shall follow the procedures in section 2.2.5(c)(8) of appendix B to this part. * * *

* * * * *

(v) * * * Automatic deadline extensions may be claimed for the two calendar quarters outside the ozone season (the first and fourth calendar quarters), since a fuel flow-to-load ratio test is not required in those quarters. * * *

* * * * *

(4) * * * The owner or operator shall include all calendar quarters in the year when determining the deadline for visual inspection of the primary fuel flowmeter element, as specified in section 2.1.6(c) of appendix D to this part.

* * * * *

(6) * * *

(v) The results of RATAs (and any other quality assurance test(s) required under paragraph (c)(2) or (c)(3) of this section) which affect data validation for the current ozone season, but which were performed outside the ozone season (i.e., between October 1 of the previous calendar year and April 30 of the current calendar year), shall be reported in the quarterly report for the second quarter of the current calendar year (or in the report for the third calendar quarter of the current calendar year, if the unit or stack does not operate in the second quarter).

(7) * * *

(ii) The standard missing data procedures of §§ 75.31 through 75.37 shall be used, with one exception. When a fuel which has a significantly higher NO_X emission rate than any of the fuel(s) combusted in prior ozone seasons is combusted in the unit, and no quality-assured NO_X data have been recorded in the current or any previous ozone season while combusting the new fuel, the owner or operator shall substitute the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter, from a NO_X-diluent continuous emission monitoring system, or the maximum potential concentration of NO_X, as defined in section 2.1.2.1 of appendix A to this part, from a NO_X concentration monitoring system. The maximum potential value used shall be specific to the new fuel. The owner or operator shall substitute the maximum potential value for each hour of missing NO_X data until the first hour that quality-assured NO_X data are obtained while combusting the new fuel, and then shall resume use of the standard missing data routines, either on a fuel-specific or non-fuel-specific basis; and

(iii) In order to apply the missing data routines described in §§ 75.31 through

75.37 on an ozone season-only basis, the procedures in those sections shall be modified as follows:

(A) The use of the initial missing data procedures in § 75.31 shall commence with the first unit operating hour in the first ozone season for which emissions data are required to be reported under § 75.64.

(B) In § 75.31(a), the phrases, ''during the first 720 quality-assured monitor operating hours within the ozone season'' and ''during the first 2,160 quality-assured monitor operating hours within the ozone season.'' apply respectively instead of the phrases ''during the first 720 quality-assured monitor operating hours'' and ''during the first 2,160 quality-assured monitor operating hours.''

(C) The sentence, ''The owner or operator of a unit shall use these procedures for no longer than three ozone seasons following initial certification'' applies instead of the last sentence of § 75.31(a).

(D) In § 75.32(a), the phrases ''the first 720 quality-assured monitor operating hours within the ozone season,'' ''the first 2,160 quality-assured monitor operating hours within the ozone season,'' and ''three ozone seasons'' apply, respectively, instead of the phrases ''the first 720 quality-assured monitor operating hours,'' ''the first 2,160 quality-assured monitor operating hours,'' and ''three years (26,280 clock hours).''

(E) In § 75.32(a)(1), the phrase ''Following initial certification, prior to completion of 3,672 unit operating hours within the subsequent ozone season(s)'' applies instead of the phrase ''Prior to completion of 8,760 unit operating hours following initial certification.''

(F) In Equation 8, the phrase ''Total unit operating hours within the ozone season'' applies instead of the phrase ''Total unit operating hours.''

(G) In § 75.32(a)(2), phrase, ''3,672 unit operating hours within the ozone season,'' applies instead of the phrase, ''8,760 unit operating hours'', and the phrase, ''three ozone seasons'' applies instead of the phrase, ''three years (26,280 clock hours).''

(H) In the numerator of Equation 9, the phrase, ''Total unit operating hours within the ozone season'' applies instead of the phrase ''Total unit operating hours'', and the phrase, ''3,672 unit operating hours within the ozone season'' applies instead of the phrase, ''8,760 unit operating hours''. In the denominator of Equation 9, the number ''3,672'' applies instead of ''8,760.''

(I) Use the following instead of the first three sentences in § 75.32(a)(3): ''When calculating percent monitor data availability using Equation 8 or 9, the owner or operator shall include all unit operating hours within the ozone season, and all monitor operating hours within the ozone season for which quality-assured data were recorded by a certified primary monitor; a certified redundant or non-redundant backup monitor or a reference method for that unit; or by an approved alternative monitoring system under subpart E of this part. No hours from more than three ozone seasons earlier shall be used in Equation 9.'' For a unit that has accumulated fewer than 3,672 unit operating hours in the previous three ozone seasons, use the following in the numerator of Equation 9, ''Total unit operating hours for which quality-assured data were recorded in the previous three ozone seasons'', and in the denominator of Equation 9 use ''Total unit operating hours in the previous three ozone seasons.''

(J) In § 75.33(a), the phrases ''the first 720 quality-assured monitor operating hours within the ozone season,'' ''the first 2,160 quality-assured monitor operating hours within the ozone season,'' and ''three ozone seasons'' apply, respectively, instead of the phrases ''the first 720 quality-assured monitor operating hours,'' ''the first 2,160 quality-assured monitor operating hours,'' and ''three years (26,280 clock hours).''

(K) Instead of the last sentence of § 75.33(a), use ''For the purposes of missing data substitution, the owner or operator of a unit shall not use quality-assured monitor operating hours of data that were recorded more than three ozone seasons prior to the ozone season in which the missing data period occurs.''

(L) In §§ 75.33(b), 75.33(c), 75.35, 75.36, and 75.37, the phrases, ''720 quality-assured monitor operating hours within the ozone season'' and ''2,160 quality-assured monitor operating hours within the ozone season'' apply, respectively, instead of the phrases ''720 quality-assured monitor operating hours'' and ''2,160 quality-assured monitor operating hours.''

(M) In § 75.34(a)(2), the phrases, ''720 (or 2,160) quality-assured monitor operating hours within the ozone season,'' ''previous 720 quality-assured monitor operating hours recorded within the ozone season in the uncontrolled database,'' and ''the requisite number of quality-assured monitor operating hours of SO_2 or NO_X data recorded within the ozone season in the appropriate database for the lookback periods,'' apply respectively instead of ''720 (or 2,160) quality-assured monitor operating hours,'' ''previous 720 quality-assured monitor operating hours in the uncontrolled database,'' and ''the requisite number of quality-assured monitor operating hours of SO_2 or NO_X data in the appropriate database for the lookback periods.''

(8) * * *

(ii) For units with add-on emission controls, using the missing data option in § 75.34(a)(1), the range of operating parameters for add-on emission controls, as described in § 75.34(a) and information for verifying proper operation of the add-on emission controls during missing data periods, as described in § 75.34(d). For units using the missing data option in § 75.34(a)(2), information documenting the operating status of the add-on emission controls during unit operation, as described in § 75.34(d).

* * * * *

Appendix A Section 1 [Amended].

47. Section 1 of Appendix A to Part 75 is amended by:

a. In section heading 1.1 by revising the words ''Pollutant Concentration and CO_2 or O_2'' to read ''Gas'';

b. In the second sentence of section 1.1 by revising the words ''SO_2 pollutant concentration monitor or NO_X'' to read ''SO_2, CO_2, O_2, or NO_X concentration monitoring system or NO_X-diluent'';

c. In section heading 1.1.1 by removing the words ''Pollutant Concentration and CO_2 or O_2'';

d. In section heading 1.1.2 by removing the words ''Pollutant Concentration and CO_2 or O_2 Gas'';

e. In the fourth sentence of section 1.2 by revising the words ''section 6.5.2'' to read ''section 6.5.2.1''; and

f. Removing the first sentence of section 1.2.2.

48. Section 2 of Appendix A to Part 75 is amended by:

a. Revising the second and third sentences of section 2.1;

b. In the first sentence of section 2.1.1 by revising the words ''this section 2'' to read ''sections 2.1.1.1 through 2.1.1.5 of this appendix'';

c. Moving Equations A–1a and A–1b and the variable equations and Note following them from paragraph (c) of section 2.1.1.1 to the end of paragraph (a) of section 2.1.1.1;

d. Revising the definition of the variable ''%S'' in Equation A–1b of paragraph (a) of section 2.1.1.1;

e. Adding a definition for the variable ''GCV'' after the definition of the variable ''$\%CO_{2w}$'' in Equation A–1b in paragraph (a) of section 2.1.1.1;

f. Adding two sentences to the end of paragraph (b) of section 2.1.1.1;

g. Adding three sentences to the end of paragraph (a) of section 2.1.1.2;

h. In the definition of MPC in Equation A–2 in paragraph (c) of section 2.1.1.2 by adding the words ''in section 2.1.1.1 of this appendix'' after the words ''as determined by Eq. A–1a or A–1b'';

i. Revising the fifth and tenth sentences of section 2.1.1.3;

j. In paragraph (c) of section 2.1.1.4 by adding a sentence after the first sentence;

k. Removing the first sentence of paragraph (d) of section 2.1.1.4 and adding three sentences in its place;

l. In the first sentence of section 2.1.1.5 by revising the words ''paragraphs (a) and (b)'' to read ''paragraphs (a), (b), and (c)'';

m. In paragraph (c) of section 2.1.1.5 by revising the final sentence;

n. In section 2.1.2 by revising the words ''section 2.1.2.1'' to read ''sections 2.1.2.1 through 2.1.2.5 of this appendix'';

o. In paragraph (a) of section 2.1.2.1 by adding two new sentences at the end of Option 1, by removing the word ''or'' from Option 3, by revising the period at the end of Option 4 to read ''; or'', and by adding a new Option 5;

p. Adding two new sentences to the end of paragraph (c) of section 2.1.2.1;

q. Revising the first sentence of paragraph (d) of section 2.1.2.1;

r. Revising the second sentence of paragraph (e) and Table 2–2 in section 2.1.2.1;

s. Revising paragraph (a) of section 2.1.2.2;

t. In the third sentence of paragraph (b) of section 2.1.2.2 by adding the words ''(if applicable)'' after the words '' NO_X emissions'';

u. Revising the second and third sentences of paragraph (c) of section 2.1.2.2;

v. Revising the fourth sentence of paragraph (a) of section 2.1.2.3;

w. In the first sentence of paragraph (b) of section 2.1.2.3 by revising the words ''requires a span'' to read ''requires or allows the use of a span value'';

x. Revising the second sentence of paragraph (b) of section 2.1.2.4 and adding a new sentence after the first sentence;

y. Removing the first sentence of paragraph (c) of section 2.1.2.4 and adding three sentences in its place;

z. In the third sentence of section 2.1.2.5 by revising the words ''paragraphs (a) and (b)'' to read ''paragraphs (a), (b), and (c)'';

aa. In paragraph (c) of section 2.1.2.5 by adding the word ''diagnostic'' before the words ''linearity test'' in the fifth sentence and by revising the final sentence;

bb. Amending section 2.1.3 by adding a sentence to the end of the section;

cc. In section 2.1.3.3 by adding two new sentences to the beginning of the section;

dd. In the fifth sentence of section 2.1.4.2 by adding the words '', as specified in section 2.2.2.1 of this appendix'' after the words ''of the calibration span value'';

ee. In section 2.1.6 by adding a sentence to the end of that section; and

ff. Revising section 2.2.

The revisions and additions read as follows:

Appendix A to Part 75—Specifications and Test Procedures

* * * * *

2. Equipment Specifications

2.1 Instrument Span and Range

* * * To meet these objectives, select the range such that the majority of the readings obtained during typical unit operation are kept, to the extent practicable, between 20.0 and 80.0 percent of the full-scale range of the instrument. These guidelines do not apply to: (1) SO_2 readings obtained during the combustion of very low sulfur fuel (as defined in § 72.2 of this chapter); (2) SO_2 or NO_X readings recorded on the high measurement range, for units with SO_2 or NO_X emission controls and two span values, unless the emission controls are operated seasonally (for example, only during the ozone season); or (3) SO_2 or NO_X readings less than 20.0 percent of full-scale on the low measurement range for a dual span unit, provided that the maximum expected concentration (MEC), low-scale span value, and low-scale range settings have been determined according to sections 2.1.1.2, 2.1.1.4(a), (b), and (g) of this appendix (for SO_2), or according to sections 2.1.2.2, 2.1.2.4(a) and (f) of this appendix (for NO_X).

2.1.1 SO_2 Pollutant Concentration Monitors * * *

2.1.1.1 Maximum Potential Concentration

(a) * * *

Where, * * *

%S = Maximum sulfur content of fuel to be fired, wet basis, weight percent, as determined according to the applicable method in paragraph (c) of section 2.1.1.1.

* * * * *

GCV = Minimum gross calorific value of the fuel or blend to be combusted, based on historical fuel sampling and analysis data or, if applicable, based on the fuel contract specifications (Btu/lb). If based on fuel sampling and analysis, the GCV shall be determined according to the applicable method in paragraph (c) of section 2.1.1.1.

* * * * *

(b) * * * Note that the initial MPC value is subject to periodic review under section 2.1.1.5 of this appendix. If an MPC value is found to be either inappropriately high or low, the MPC shall be adjusted in accordance with section 2.1.1.5, and corresponding span and range adjustments shall be made, if necessary.

* * * * *

2.1.1.2 Maximum Expected Concentration

(a) * * * Each initial MEC value shall be documented in the monitoring plan required under § 75.53. Note that each initial MEC value is subject to periodic review under section 2.1.1.5 of this appendix. If an MEC value is found to be either inappropriately high or low, the MEC shall be adjusted in accordance with section 2.1.1.5, and corresponding span and range adjustments shall be made, if necessary.

* * * * *

2.1.1.3 Span Value(s) and Range(s)

* * * If the SO_2 span concentration is ≤ 500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm. * * * If an existing State, local, or federal requirement for span of an SO_2 pollutant concentration monitor requires or allows the use of a span value lower than that required by this section or by section 2.1.1.4 of this appendix, the State, local, or federal span value may be used if a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix. * * *

2.1.1.4 Dual Span and Range Requirements

* * * * *

(c) * * * Alternatively, if RATAs are performed and passed on both measurement ranges, the owner or operator may use two separate SO_2 analyzers connected to separate probes and sample interfaces. * * *

(d) The owner or operator shall designate the monitoring systems and components in the monitoring plan under § 75.53 as follows: when a single probe and sample interface are used, either designate the low and high monitor ranges as separate SO_2 components of a single, primary SO_2 monitoring system; designate the low and high monitor ranges as the SO_2 components of two separate, primary SO_2 monitoring systems; designate the normal monitor range as a primary monitoring system and the other monitor range as a non-redundant backup monitoring system; or, when a single, dual-range SO_2 analyzer is used, designate the low and high ranges as a single SO_2 component of a primary SO_2 monitoring system (if this option is selected, use a special dual-range component type code, as specified by the Administrator, to satisfy the requirements of § 75.53(e)(1)(iv)(D)). When two SO_2 analyzers are connected to separate probes and sample interfaces, designate the analyzers as the SO_2 components of two separate, primary SO_2 monitoring systems. For units with SO_2 controls, if the default high range value is used, designate the low range analyzer as the SO_2 component of a primary SO2 monitoring system. * * *

* * * * *

2.1.1.5 Adjustment of Span and Range

* * * * *

(c) * * * Use the data validation procedures in § 75.20(b)(3), beginning with the hour in which the span is changed.

* * * * *

2.1.2.1 Maximum Potential Concentration

(a) * * *

Option 1: * * * For cement kilns, use 2000 ppm as the MPC. For process heaters, use 200 ppm if the unit burns only gaseous fuel and 500 ppm if the unit burns oil;

* * * * *

Option 5: If a reliable estimate of the uncontrolled NO_X emissions from the unit is available from the manufacturer, the estimated value may be used.

* * * * *

(c) * * * Note that whichever MPC option in section 2.1.2.1(a) of this appendix is selected, the initial MPC value is subject to periodic review under section 2.1.2.5 of this appendix. If an MPC value is found to be either inappropriately high or low, the MPC shall be adjusted in accordance with section 2.1.2.5, and corresponding span and range adjustments shall be made, if necessary.

(d) For units with add-on NO_X controls (whether or not the unit is equipped with low-NO_X burner technology), or for units equipped with dry low-NO_X (DLN) technology, NO_X emission testing may only be used to determine the MPC if testing can be performed either upstream of the add-on controls or during a time or season when the add-on controls or DLN are not in operation. * * *

(e) * * * For a unit with add-on NO_X controls (whether or not the unit is equipped with low-NO_X burner technology), or for a unit equipped with dry low-NO_X (DLN) technology, historical CEM data may only be used to determine the MPC if the 720 quality assured monitor operating hours of CEM data are collected upstream of the add-on controls or if the 720 hours of data include periods when the add-on controls or DLN are not in operation. * * *

TABLE 2–2.—MAXIMUM POTENTIAL CONCENTRATION FOR NO_X—GAS- AND OIL-FIRED UNITS

Unit type	Maximum potential concentration for NO_X (ppm)
Tangentially-fired dry bottom	380
Wall-fired dry bottom	600
Roof-fired (vertically-fired) dry bottom, arch-fired	550
Existing combustion turbine	200
New combustion turbine, permitted to fire either oil or natural gas	200
New combustion turbine, permitted to fire only natural gas	150
Others	(1)

1 As approved by the Administrator.

2.1.2.2 Maximum Expected Concentration

(a) Make an initial determination of the maximum expected concentration (MEC) of NO_X during normal operation for affected units with add-on NO_X controls of any kind (e.g., steam injection, water injection, SCR, or SNCR) and for turbines that use dry low-NO_X technology. Also determine the MEC for uncontrolled units and units that use only low NO_X burners (LNB) for NO_X control, if more than one type of fuel is combusted in the unit. Determine a separate MEC value for each type of fuel (or blend) combusted in the unit, except for fuels that are only used for unit startup and/or flame stabilization and except for the fuel or blend that was used to determine the MPC under section 2.1.2.1 of this appendix. Calculate the MEC of NO_X using Equation A–2, if applicable, inserting the maximum potential concentration, as determined using the procedures in section 2.1.2.1 of this appendix. Where Equation A–2 is not applicable, set the MEC either by: (1) Measuring the NO_X concentration using the testing procedures in this section; (2) using historical CEM data over the previous 720 (or more) quality assured monitor operating hours; or (3) if the unit has add-on NO_X controls or uses dry low NO_X technology, and has a federally-enforceable permit limit for NO_X concentration, the permit limit may be used as the MEC. Include in the monitoring plan for the unit each MEC value and the method by which the MEC was determined. Note that each initial MEC value is subject to periodic review under section 2.1.2.5 of this appendix. If an MEC value is found to be either inappropriately high or low, the MEC shall be adjusted in accordance with section 2.1.2.5, and corresponding span and range adjustments shall be made, if necessary.

* * * * *

(c) * * * The data base for the MEC shall not include any CEM data recorded during unit startup, shutdown, or malfunction or (for units with add-on NO_X controls or turbines using dry low NO_X technology) during any NO_X control device malfunctions or outages. All NO_X control devices and methods used to reduce NO_X emissions (if applicable) must be operating properly during each hour. * * *

2.1.2.3 Span Value(s) and Range(s)

(a) * * * If the NO_X span concentration is ≤500 ppm, the span value may either be rounded upward to the next highest multiple of 10 ppm, or to the next highest multiple of 100 ppm. * * *

* * * * *

2.1.2.4 Dual Span and Range Requirements

* * * * *

(b) * * * Two separate NO_X analyzers connected to separate probes and sample interfaces may be used if RATAs are passed on both ranges. For units with add-on NO_X emission controls (e.g., steam injection, water injection, SCR, or SNCR) or units equipped with dry low-NO_X technology, the owner or operator may use a low range analyzer and a ''default high range value,'' as described in section 2.1.2.4(e) of this appendix, in lieu of maintaining and quality assuring a high-scale range. * * *

(c) The owner or operator shall designate the monitoring systems and components in the monitoring plan under § 75.53 as follows: When a single probe and sample interface are used, either designate the low and high ranges as separate NO_X components of a single, primary NO_X monitoring system; designate the low and high ranges as the NO_X components of two separate, primary NO_X monitoring systems; designate the normal range as a primary monitoring system and the other range as a non-redundant backup monitoring system; or, when a single, dual-range NO_X analyzer is used, designate the low and high ranges as a single NO_X component of a primary NO_X monitoring system (if this option is selected, use a special dual-range component type code, as specified by the Administrator, to satisfy the requirements of § 75.53(e)(1)(iv)(D)). When two NO_X analyzers are connected to separate probes and sample interfaces, designate the analyzers as the NO_X components of two separate, primary NO_X monitoring systems. For units with add-on NO_X controls or units equipped with dry low-NO_X technology, if the default high range value is used, designate the low range analyzer as the NO_X component of the primary NO_X monitoring system. * * *

* * * * *

2.1.2.5 Adjustment of Span and Range

* * * * *

(c) * * * Use the data validation procedures in § 75.20(b)(3), beginning with the hour in which the span is changed.

2.1.3 CO_2 and O_2 Monitors

* * * If a dual-range or autoranging diluent analyzer is installed, the analyzer may be represented in the monitoring plan as a single component, using a special component type code specified by the Administrator to satisfy the requirements of § 75.53(e)(1)(iv)(D).

* * * * *

2.1.3.3 Adjustment of Span and Range

The MPC and MEC values for diluent monitors are subject to the same periodic review as SO_2 and NO_X monitors (see sections 2.1.1.5 and 2.1.2.5 of this appendix). If an MPC or MEC value is found to be either inappropriately high or low, the MPC shall be adjusted and corresponding span and range adjustments shall be made, if necessary. * * *

* * * * *

2.1.6 Maximum Potential Moisture Percentage

* * * Alternatively, a default maximum potential moisture value of 15 percent H_2O may be used.

2.2 Design for Quality Control Testing

2.2.1 Pollutant Concentration and CO_2 or O_2 Monitors

(a) Design and equip each pollutant concentration and CO_2 or O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (e.g., sample lines, filters, scrubbers, conditioners, and as much of the probe as practicable) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all active electronic and optical components (e.g. transmitter, receiver, analyzer).

(b) Design and equip each pollutant concentration or CO_2 or O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero- and mid- or high-level concentrations specified in section 5.2 of this appendix.

2.2.2 Flow Monitors

Design all flow monitors to meet the applicable performance specifications.

2.2.2.1 Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: (1) Zero to 20 percent of span or an equivalent reference value (e.g., pressure pulse or electronic signal) and (2) 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of (1) the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system, or (2) the flow monitoring system from and including the transducer through and including the data acquisition and handling system.

2.2.2.2 Interference Check

(a) Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

(b) Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent velocity sensing interference, and (2) a means for detecting leaks in the system on at least a quarterly basis (manual check is acceptable).

(c) Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

(d) Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (e.g., backpurging system) to prevent velocity sensing interference.

Appendix A to Part 75 [Amended]

49. Section 3 of Appendix A to Part 75 is amended by:

a. In section heading 3.3.1 by adding the word ''Monitors'' after the word ''SO_2'';

b. Revising section 3.3.1;

c. Revising paragraph (a) of section 3.3.2;

d. In the first sentence of paragraph (b) of section 3.3.2 by revising the words ''not exceed'' to read ''be within'';

e. In section heading 3.3.3 by removing the words ''Pollutant Concentration'';

f. In paragraph 3.3.3 by adding ''±'' before the words ''1.0 percent'';

g. In section heading 3.3.4 by adding the word ''Monitors'' after the word ''Flow'';

h. Revising section 3.3.4;

i. In the second sentence of section 3.3.6 by revising the words ''appendix are'' to read ''appendix is''; and

j. Revising the second sentence of paragraph (b) of section 3.3.7.

The revisions and additions read as follows:

3. Performance Specifications

* * * * *

3.3 Relative Accuracy

3.3.1 Relative Accuracy for SO_2 Monitors

(a) The relative accuracy for SO_2 pollutant concentration monitors shall not exceed 10.0 percent except as provided below in this section.

(b) For affected units where the average of the reference method measurements of SO_2 concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the mean value of the monitor measurements shall be within ±15.0 ppm of the reference method mean value wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.2 Relative Accuracy for NO_X-Diluent Continuous Monitoring Systems

(a) The relative accuracy for NO_X-diluent continuous emission monitoring systems shall not exceed 10.0 percent at any load level at which a RATA is performed (the low, mid, or high load level, as defined in section 6.5.2.1 of this appendix).

* * * * *

3.3.4 Relative Accuracy for Flow Monitors

(a) The relative accuracy of flow monitors shall not exceed 10.0 percent at any load level at which a RATA is performed (the low, mid, or high load level, as defined in section 6.5.2.1 of this appendix).

(b) For affected units where the average of the flow reference method measurements of gas velocity at a particular load level of the relative accuracy test audit is less than or equal to 10.0 fps, the mean value of the flow monitor velocity measurements shall be within ±2.0 fps of the reference method mean value in fps at that load level, wherever the 10.0 percent relative accuracy specification is not achieved.

* * * * *

3.3.7 Relative Accuracy for NO_X Concentration Monitoring Systems

* * * * *

(b) * * * Alternatively, for affected units where the average of the reference method measurements of NO_X concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the mean value of the continuous emission monitoring system measurements shall be within ±15.0 ppm of the reference method mean value.

* * * * *

50. Section 4 of Appendix A to Part 75 is amended by:

a. Revising the second sentence of the first paragraph of section 4;

b. Removing the last sentence of the first paragraph of section 4; and

c. In subparagraph (3) of section 4 by adding the words ''the appropriate'' before the word ''units'', by removing the words ''of the standard'', and by adding the word ''e.g.,'' before the words ''lb/hr''.

The revisions and additions read as follows:

4. Data Acquisition and Handling Systems

* * * These systems also shall have the capability of interpreting and converting the individual output signals from an SO_2 pollutant concentration monitor, a flow monitor, a CO_2 monitor, a NO_X pollutant concentration monitor, and a NO_X-diluent continuous emission monitoring system to produce a continuous readout of pollutant mass emission rates in the appropriate units (e.g., lb/hr, lb/mmBtu, tons/hr). * * *

* * * * *

Appendix A to Part 75 [Amended]

51. Section 6 of Appendix A to Part 75 is amended by:

a. In the first sentence of paragraph (a) of section 6.2 by adding the word ''conditional'' before the words ''data validation procedures'';

b. In section 6.3.1 by removing the word ''extended'' before the words ''unit outages'' in the second sentence, and by adding a new sentence after the second sentence;

c. In the first sentence of paragraph (a) of section 6.3.1 by adding the word ''conditional'' before the words ''data validation procedures'';

d. In the fourth sentence of section 6.3.2 by removing the word ''extended'' before the words ''unit outages'', and by adding a new sentence after the fourth sentence;

e. In the first sentence of paragraph (a) of section 6.3.2 by adding the word ''conditional'' before the words ''data validation procedures'';

f. In the first sentence of paragraph (a) of section 6.4 by adding the word ''conditional'' before the words ''data validation procedures'';

g. In the first sentence of section 6.5 by adding the word ''and'' after the words ''heat input,'' and by removing the words ''and each SO_2-diluent continuous emission monitoring system'';

h. Revising paragraphs (a) and (c) of section 6.5;

i. In the first sentence of paragraph (f)(1) of section 6.5 by adding the word ''conditional'' before the words ''data validation procedures'';

j. In the second sentence of paragraph (g) of section 6.5 by removing the words ''SO_2-diluent'';

k. Revising paragraph (a) of section 6.5.1 and paragraph (a) of section 6.5.2;

l. In paragraph (b) of section 6.5.2 by revising the words ''section 6.5.2.1'' to read ''section 6.5.2.1(d)'';

m. In paragraph (c) of section 6.5.2 by adding the words ''(or three operating levels)'' after the word ''level(s)'';

n. In paragraph (d) of section 6.5.2 by adding the words ''(or operating levels)'' after the word ''level(s)'';

o. In section heading 6.5.2.1 by adding the words ''(or Operating)'' after the words ''Normal Load'';

p. Revising paragraph (a) of section 6.5.2.1;

q. In the first sentence of paragraph (b) of section 6.5.2.1 by revising the words ''30.0 to 60.0 percent'' to read ''> 30.0 percent, but ≤ 60.0 percent'' and revising the words ''60.0 to 100.0 percent'' to read ''> 60.0 percent'';

r. Revising paragraphs (c) and (d) of section 6.5.2.1;

s. Revising the first sentence of paragraph (e) of section 6.5.2.1;

t. Removing and reserving section 6.5.3;

u. Amending section 6.5.6 by removing the third sentence;

v. In paragraph (b)(2) of section 6.5.6 by revising the number ''1.0'' To read ''1.2'';

w. Adding paragraph (b)(5) to section 6.5.6;

x. In the first sentence of paragraph (a) of sections 6.5.6.1 and 6.5.6.2 by revising the words ''normal load'' to read ''the normal load level (or normal operating level)'';

y. In paragraph (c) of section 6.5.6.3 by removing the words ''§ 75.56(a)(7) or'' and the words '', as applicable'';

z. In paragraph (a) of section 6.5.7 by removing the words ''or SO_2-diluent'' in the fourth sentence, by adding one sentence before, and two sentences after, the ninth sentence, and by removing the words ''§ 75.56(a)(5)(ix) and'' from the next to last sentence; and

aa. In section 6.5.10 by adding a comma after the number ''7D'', and by adding a new third sentence.

The revisions and additions read as follows:

6. Certification Tests and Procedures

* * * * *

6.3 7-Day Calibration Error Test

6.3.1 Gas Monitor 7-Day Calibration Error Test

* * * Notwithstanding this requirement, for a peaking unit (as defined in § 72.2 of this chapter), only 3 of the 7 days in the test need be unit operating days. * * *

* * * * *

6.3.2 Flow Monitor 7-Day Calibration Error Test

* * * Notwithstanding these requirements, for a peaking unit (as defined in § 72.2 of this chapter), only 3 of the 7 days in the test need be unit operating days. * * *

* * * * *

6.5 Relative Accuracy and Bias Tests (General Procedures)

* * * * *

(a) Except as provided in § 75.21(a)(5), perform each RATA while the unit (or units, if more than one unit exhausts into the flue) is combusting the fuel that is a normal primary or backup fuel for that unit (for some units, more than one type of fuel may be considered normal, e.g., a unit that combusts gas or oil on a seasonal basis). For units that co-fire fuels as the predominant mode of operation, perform the RATAs while co-firing. When relative accuracy test audits are performed on continuous emission monitoring systems installed on bypass stacks/ducts, use the fuel normally combusted by the unit (or units, if more than one unit exhausts into the flue) when emissions exhaust through the bypass stack/ducts.

* * * * *

(c) For monitoring systems with dual ranges, perform the relative accuracy test on the range normally used for measuring emissions. For units with add-on SO_2 or NO_X controls that operate continuously rather than seasonally, or for units that need a dual range to record high concentration ''spikes'' during startup conditions, the low range is considered normal. However, for some dual span units (e.g., for units that use fuel switching or for which the emission controls are operated seasonally), provided that both monitor ranges are connected to a common probe and sample interface, either of the two measurement ranges may be considered normal; in such cases, perform the RATA on the range that is in use at the time of the scheduled test. If the low and high measurement ranges are connected to separate sample probes and interfaces, RATA testing on both ranges is required.

* * * * *

6.5.1 Gas Monitoring System RATAs (Special Considerations)

(a) Perform the required relative accuracy test audits for each SO_2 or CO_2 pollutant concentration monitor, each CO_2 or O2 diluent monitor used to determine heat input, each NO_X-diluent continuous emission monitoring system, and each NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2) at the normal load level or normal operating level for the unit (or combined units, if common stack), as defined in section 6.5.2.1 of this appendix. If two load levels or operating levels have been designated as normal, the RATAs may be done at either load level.

* * * * *

6.5.2 Flow Monitor RATAs (Special Considerations)

(a) Except for flow monitors on bypass stacks/ducts and peaking units, perform relative accuracy test audits for the initial certification of each flow monitor at three different exhaust gas velocities (low, mid, and high), corresponding to three different load levels or operating levels within the range of operation, as defined in section 6.5.2.1 of this appendix. For a common stack/duct, the three different exhaust gas velocities may be obtained from frequently used unit/load or operating level combinations for the units exhausting to the common stack. Select the three exhaust gas velocities such that the audit points at adjacent load or operating levels (i.e., low and mid or mid and high), in megawatts (or in thousands of lb/hr of steam production or in ft/sec, as applicable), are separated by no less than 25.0 percent of the range of operation, as defined in section 6.5.2.1 of this appendix.

* * * * *

6.5.2.1 Range of Operation and Normal Load (or Operating) Load Level(s)

(a) The owner or operator shall determine the upper and lower boundaries of the ''range of operation'' as follows for each unit (or combination of units, for common stack configurations) 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:

(1) For affected units that produce electrical output (in megawatts) or thermal output (in klb/hr of steam production), the lower boundary of the range of operation of a unit shall be the minimum safe, stable load. For common stacks, the minimum safe, stable load shall be the lowest of the minimum safe, stable loads for any of the units discharging through the stack. Alternatively, for a group of frequently-operated units that serve a common stack, the sum of the minimum safe, stable loads for the individual units may be used as the lower boundary of the range of operation. The upper boundary of the range of operation of a unit shall be the maximum sustainable load. The ''maximum sustainable load'' is the higher of either: the nameplate or rated capacity of the unit, less any physical or regulatory limitations or other deratings; or the highest sustainable unit load, based on at least four quarters of representative historical operating data. For common stacks, the maximum sustainable load is the sum of all of the maximum sustainable loads of the individual units discharging through the stack, unless this load is unattainable in practice, in which case use the highest sustainable combined load for the units that discharge through the stack, based on at least four quarters of representative historical operating data. The load values for the unit(s) shall be expressed either in units of megawatts or thousands of lb/hr of steam load; or

(2) For affected units that do not produce electrical or thermal output, the lower boundary of the range of operation shall be the minimum expected flue gas velocity (in ft/sec) during normal, stable operation of the unit. The upper boundary of the range of operation shall be the maximum potential flue gas velocity (in ft/sec) as defined in section 2.1.4.1 of this appendix. The minimum expected and maximum potential velocities may be derived from the results of reference method testing or by using Equation A–3a or A–3b (as applicable) in section 2.1.4.1 of this appendix. If Equation A-3a or A–3b is used to determine the minimum expected velocity, replace the word ''maximum'' to read ''minimum'' in the definitions of ''MPV,'' ''H_f,'' ''% O_{2d},'' and ''% H_2O,'' and replace the word ''minimum'' to read ''maximum'' in the definition of ''CO_{2d}.''

* * * * *

(c) *Analysis of historical load or operating level data.* (1) For units that produce electrical or thermal output, the owner or operator shall identify, for each affected unit or common stack (except for peaking units), the ''normal'' load level or levels (low, mid or high), based on the operating history of the unit(s). To identify the normal load level(s), the owner or operator shall, at a minimum, determine the relative number of operating hours at each of the three load levels, low, mid and high over the past four representative operating quarters. The owner or operator shall determine, to the nearest 0.1 percent, the percentage of the time that each load level (low, mid, high) has been used during that time period. A summary of the data used for this determination and the calculated results shall be kept on-site in a format suitable for inspection. For new units or newly-affected units, the data analysis in this paragraph may be based on fewer than four quarters of data if fewer than four representative quarters of historical load data are available. Or, if no historical load data are available, the owner or operator may designate the normal load based on the expected or projected manner of operating the unit. However, in either case, once four quarters of representative data become available, the historical load analysis shall be repeated.

(2) If the affected unit does not produce electrical or steam load, follow the procedures in paragraph (c)(1) of this section, except that:

(i) The words ''load level'' shall read ''operating level;'' and

(ii) If the unit does not have an installed flow monitor, the historical data analysis described in paragraph (c)(1) of this section is not required.

(d) *Determination of normal load.* (1) Based on the analysis of the historical load data described in paragraph (c) of this section, the owner or operator shall, for units that produce electrical or thermal output, designate the most frequently used load level as the normal load level for the unit (or combination of units, for common stacks). The owner or operator may also designate the second most frequently used load level as an additional normal load level for the unit or stack. For peaking units, normal load designations are unnecessary; the entire operating load range shall be considered normal. If the manner of operation of the unit changes significantly, such that the designated normal load(s) or the two most frequently used load levels change, the owner or operator shall repeat the historical load analysis and shall redesignate the normal load(s) and the two most frequently used load levels, as appropriate. A minimum of two representative quarters of historical load data are required to document that a change in the manner of unit operation has occurred. Update the electronic monitoring plan whenever the normal load level(s) and the two most frequently-used load levels are redesignated.

(2) For units that do not produce electrical or thermal output, follow the procedures in paragraph (d)(1) of this section, except that:

(i) The words ''load'' and ''load level'' shall read ''operating level;'' and

(ii) If the unit does not have an installed flow monitor, the two most frequently-used operating levels and the normal operating level(s) shall be determined using sound engineering judgment, in lieu of performing a historical data analysis. The operating level determinations shall be based on knowledge of the unit, operating experience with the unit, and actual stack gas velocity measurements using EPA Method 2 in appendix A to part 60 of this chapter (or its allowable alternatives).

(e) The owner or operator shall report the upper and lower boundaries of the range of operation for each unit (or combination of units, for common stacks), in units of megawatts or thousands of lb/hr of steam production or ft/sec (as applicable), in the electronic quarterly report required under § 75.64. * * *

* * * * *

6.5.6 Reference Method Traverse Point Selection

* * * * *

(b) * * *

(5) If Method 7E is used as the reference method for the RATA of a NO_X CEMS installed on a combustion turbine, the reference method measurements may be made at the sampling points specified in section 6.1.2 of Method 20 in appendix A to part 60 of this chapter.

* * * * *

6.5.7 Sampling Strategy

(a) * * * Also, allow sufficient measurement time to ensure that stable temperature readings are obtained at each traverse point, particularly at the first measurement point at each sample port, when a probe is moved sequentially from port-to-port. * * * Alternatively, moisture measurements for molecular weight determination may be performed before and after a series of RATA runs at a particular load level (low, mid, or high), provided that the time interval between the two moisture measurements does not exceed three hours. If this option is selected, the results of the two moisture determinations shall be averaged arithmetically and applied to all RATA runs in the series. * * *

* * * * *

6.5.10 Reference Methods

* * * Notwithstanding these requirements, Method 20 may be used as the reference method for relative accuracy test audits of NO_X monitoring systems installed on combustion turbines.

Appendix A to Part 75 [Amended]

52. Section 7 of Appendix A to Part 75 is amended by:

a. In section heading 7.3 by revising the words ''SO_2–Diluent Continuous Emission'' to read ''O_2 Monitors, NO_X Concentration'';

b. Revising the first sentence of section 7.3;

c. Revising the variable

$$"\sum_{i=l}^{n}"$$

in the list of defined variables for Eq. A–7 to be

$$"\sum_{i=1}^{n} d_i"$$

and removing the final sentence of section 7.3.1;

d. In the section heading and text of section 7.4 by revising the word '' NO_X'' to read '' NO_X-diluent'';

e. In section heading 7.4.2 by removing the words ''(Monitoring System)'';

f. In the second sentence of section 7.6.1 by adding the words ''or NO_X'' after both occurrences of the word ''SO_2'' and the third sentence by revising the word '' NO_X'' to read ''NO_Xdiluent'';

g. In paragraph (a) of section 7.7 by removing the fourth sentence;

h. In paragraph (b) of section 7.7 by removing the first two sentences and adding four new sentences;

i. In the variable ''(Heat Input)$_{avg}$'' under Eq. A–13a in paragraph (c) of section 7.7 by adding a second and third sentence to the definition;

j. In paragraph (d) of section 7.7 by adding the words ''(i.e., the arithmetic average of the diluent gas concentrations for all clock hours in which a RATA run was performed)'' to the end of the sentence;

k. In section 7.8 by designating the existing text as paragraph (a), removing the first sentence, adding the words ''and section 2.2.5 of appendix B to this part'' to the end of the second sentence, and adding a new paragraph (b); and

l. Revising Figure 6.

The revisions and additions read as follows:

7. Calculations

* * * * *

7.3 Relative Accuracy for SO_2 and CO_2 Pollutant Concentration Monitors, O_2 Monitors, NO_X Concentration Monitoring Systems, and Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for SO_2 and CO_2 pollutant concentration monitors, O_2 monitors used only for heat input rate determination, NO_X concentration monitoring systems, and flow monitors using the following procedures. * * *

* * * * *

7.7 Reference Flow-to-Load Ratio or Gross Heat Rate

* * * * *

(b) In Equation A–13, for a common stack, determine L_{avg} by summing, for each RATA run, the operating loads of all units discharging through the common stack, and then taking the arithmetic average of the summed loads. For a unit that discharges its emissions through multiple stacks, either determine a single value of Q_{ref} for the unit or a separate value of Q_{ref} for each stack. In the former case, calculate Q_{ref} by summing, for each RATA run, the volumetric flow rates through the individual stacks and then taking the arithmetic average of the summed RATA run flow rates. In the latter case, calculate the value of Q_{ref} for each stack by taking the arithmetic average, for all RATA runs, of the flow rates through the stack. * * *

(c) * * *

$(\text{Heat Input})_{avg}$ = * * * For multiple stack configurations, if the reference GHR value is determined separately for each stack, use the hourly heat input measured at each stack. If the reference GHR is determined at the unit level, sum the hourly heat inputs measured at the individual stacks.

* * * * *

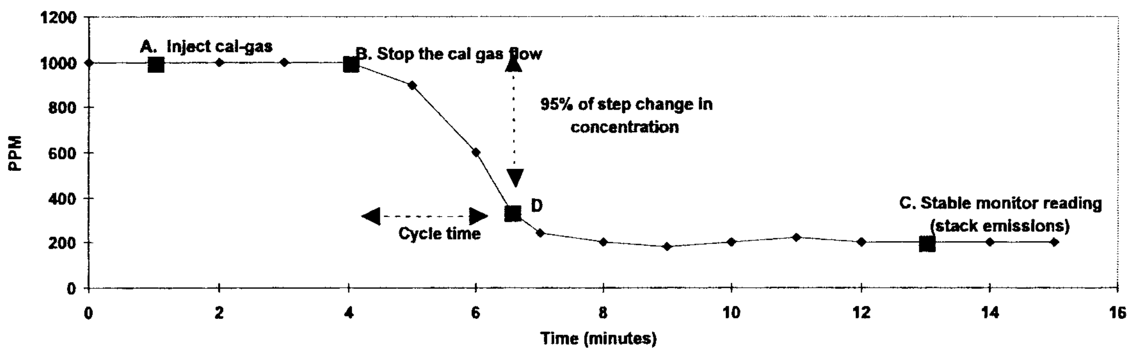
7.8 Flow-to-Load Test Exemptions

* * * * *

(b) Units that do not produce electrical output (in megawatts) or thermal output (in klb of steam per hour) are exempted from the flow-to-load ratio test requirements of section 7.7 of this appendix and section 2.2.5 of appendix B to this part.

* * * * *

Figure 6. Downscale Cycle Time Test



* * * * *

53. Section 1 of Appendix B to Part 75 is amended by:

a. Adding a fourth sentence to section 1; and

b. Removing the word ''and'' before the words ''section 2.1.5.1'' in the second sentence of section 1.3.1.

The revisions and additions read as follows:

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Assurance/Quality Control Program

* * * Electronic storage of the information in the QA/QC plan is permissible, provided that the information can be made available in hardcopy upon request during an audit.

* * * * *

54. Section 2 of Appendix B to Part 75 is amended by:

a. In paragraph (a) of section 2.1.4 by revising the words ''< 200 ppm'' in the first sentence to read ''> 50.0 ppm but ≤ 200 ppm, or exceeds 5.0 ppm for span values ≤ 50.0 ppm'';

b. In the first sentence of section 2.2.1 by revising the word ''Perform'' to read ''Unless a particular monitor (or monitoring range) is exempted under this paragraph or under section 6.2 of appendix A to this part, perform'';

c. In paragraph (c) of section 2.2.3 by adding a third sentence;

d. In the second sentence of paragraph (e) of section 2.2.3 by removing the words ''or SO_2-diluent'';

e. In the second sentence of paragraph (f) of section 2.2.3 by revising the words ''168 unit operating hour or stack operating hour grace period'' to read ''grace period of 168 cumulative unit or stack operating hours'';

f. In paragraph (a) of section 2.2.4 by revising both occurrences of the word ''consecutive'' to read ''cumulative'';

g. In the first sentence of paragraph (b) of section 2.2.4 by adding the word ''cumulative'' after the number ''168'' and the words ''first unit operating'' before the words ''hour following'';

h. In paragraph (a) of section 2.2.5 by removing the first sentence, revising the words ''by an approved petition in accordance with'' in the second sentence to read ''from the flow-to-load ratio test under'', and by adding a final sentence before Eq. B–1;

i. Revising the third sentence of paragraph (a)(1) of section 2.2.5;

j. In paragraph (a)(3) of section 2.2.5 by adding the word ''rate'' after the words ''heat input'';

k. In paragraph (a)(4) of section 2.2.5 by adding the word ''acceptable'' after each occurrence of the number ''168'', and by adding in the third sentence the words ''(i.e., at loads within ± 10 percent of L_{avg})'' after the word ''rates'';

l. Revising the last sentence of paragraph (b) of section 2.2.5;

m. Revising the introductory text of paragraph (c) of section 2.2.5;

n. Adding a new third sentence in paragraph (c)(1) of section 2.2.5;

o. In paragraph (c)(8) of section 2.2.5 by removing the second sentence and adding two new sentences in its place;

p. In the first sentence of the introductory paragraph to section 2.2.5.1 by revising the words ''two weeks'' to read ''14 unit operating days'';

q. Revising paragraph (b) of section 2.2.5.1;

r. Revising section 2.2.5.2;

s. Revising the second and third sentences of paragraph (a) of section 2.2.5.3;

t. In the second sentence of paragraph (b) of section 2.2.5.3 by changing the number ''5.0'' to ''10.0'';

u. In paragraph (c) of section 2.2.5.3 by adding the words ''(if applicable)'' after the words ''flow-to-load test'' in the second sentence and after the words ''flow monitor'' in the third sentence;

v. In the fourth sentence of paragraph (a) of section 2.3.1.1 by revising the words ''720 unit (or stack) operating hour grace period'' to read ''grace period of 720 cumulative unit or stack operating hours'';

w. Removing and reserving paragraph (b) of section 2.3.1.2;

x. Removing the words ''On and after January 1, 2000,'' and capitalizing the letter ''t'' in the first instance of ''the'' in paragraph (c) of section 2.3.1.2;

y. In paragraph (d) of section 2.3.1.2 by adding the words '', as measured by the reference method during the RATA'' after the words ''≤10.0 fps'' and by removing the words ''(10.0 percent if prior to January 1, 2000)'';

z. In paragraph (e) of section 2.3.1.2 by adding the words ''reference method'' before the word ''concentrations'', and by adding the words '') during the RATA'' after the words ''250 ppm'';

aa. In paragraph (f) of section 2.3.1.2 by adding the words ''measured by the reference method during the RATA'' after the words ''average NO_X emission rate'';

bb. Removing and reserving paragraph (g) of section 2.3.1.2;

cc. In section heading 2.3.1.3 by adding the words ''(or Operating)'' after the words ''RATA Load'';

dd. In paragraph (a) of section 2.3.1.3 by adding the words ''(or operating level)'' after each instance of the words ''load level'', adding the words ''(or operating levels)'' after the words ''load levels'', and by revising the words ''section 6.5.2.1'' to read ''section 6.5.2.1(d)'';

ee. In paragraph (b) of section 2.3.1.3 by revising the words ''section 6.5.2.1'' to read ''section 6.5.2.1(d)'';

ff. Revising paragraphs (c)(1) through (c)(6) of section 2.3.1.3;

gg. In paragraph (c) of section 2.3.2 by adding a new third sentence;

hh. In paragraphs (d) and (f) of section 2.3.2 by adding the words ''(or operating level)'' after each occurrence of the words ''load level'', the words ''(or single-level)'' after the word ''single-load'', the words ''(or multiple-level)'' after the word ''multiple-load'', the words ''(or operating level(s))'' after the words ''load level(s)'', and the words ''(or 3-level)'' after the words ''3-load'';

ii. Revising paragraph (e) of section 2.3.2;

jj. In paragraph (a) of section 2.3.3 by revising the first two instances of the word ''consecutive'' to read ''cumulative'', removing the word ''or'' after the first two semicolons, and by removing the words ''consecutive calendar'' after the word ''five'';

kk. In the first sentence of paragraph (c) of section 2.3.3 by adding the word ''cumulative'' after the number ''720'';

ll. Revising paragraph (b) of section 2.4;

mm. Revising footnote 2 of Figure 1 to Appendix B of Part 75; and

nn. In Figure 2 to Appendix B of Part 75 by removing the row for ''Flow (Phase I)'', renaming the row for ''Flow (Phase II)'' as ''Flow'', by revising the word ''H_2O_2'' in the final row to read ''H_2O^2'', and by adding the word ''cumulative'' after both occurrences of the number ''168'' in footnote 1 to Figure 2.

The revisions and additions read as follows:

2. Frequency of Testing

* * * * *

2.2 Quarterly Assessments

* * * * *

2.2.3 Data Validation

* * * * *

(c) * * * If a routine daily calibration error test is performed and passed just prior to a linearity test (or during a linearity test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the linearity test data.

* * * * *

2.2.5 Flow-to-Load Ratio or Gross Heat Rate Evaluation

(a) *Applicability and methodology.* * * * Alternatively, for the reasons stated in paragraphs (c)(1) through (c)(6) of this section, the owner or operator may exclude from the data analysis certain hours within ± 10.0 percent of L_{avg} and may calculate R_h values for only the remaining hours. * * *

(1) * * * For a unit that discharges its emissions through multiple stacks or that monitors its emissions in multiple breechings, Q_h will be either the combined hourly volumetric flow rate for all of the stacks or ducts (if the test is done on a unit basis) or the hourly flow rate through each stack individually (if the test is performed separately for each stack). * * *

* * * * *

(b) * * * If E_f is above these limits, the owner or operator shall either: implement Option 1 in section 2.2.5.1 of this appendix; perform a RATA in accordance with Option 2 in section 2.2.5.2 of this appendix; or (if applicable) re-examine the hourly data used for the flow-to-load or GHR analysis and recalculate E_f, after excluding all non-representative hourly flow rates, as provided in paragraph (c) of this section.

(c) *Recalculation of E_f.* If the owner or operator did not exclude any hours within ±10 percent of L_{avg} from the original data analysis and chooses to recalculate E_f, the flow rates for the following hours are considered non-representative and may be excluded from the data analysis:

(1) * * * Also, for units that co-fire different types of fuels, if the reference RATA was done while co-firing, then hours in which a single fuel was combusted may be excluded from the data analysis as different fuel hours (and vice-versa for co-fired hours, if the reference RATA was done while combusting only one type of fuel);

* * * * *

(8) * * * If, however, E_f is still above the applicable limit, data from the monitor shall be declared out-of-control, beginning with the first unit operating hour following the quarter in which E_f exceeded the applicable limit. Alternatively, if a probationary calibration error test is performed and passed according to § 75.20(b)(3)(ii), data from the monitor may be declared conditionally valid following the quarter in which E_f exceeded the applicable limit. * * *

2.2.5.1 Option 1

* * * * *

(b) If a problem with the flow monitor is identified through the investigation (including the need to re-linearize the monitor by changing the polynomial coefficients or K factor(s)), data from the monitor are considered invalid back to the first unit operating hour after the end of the calendar quarter for which E_f was above the applicable limit. If the option to use conditional data validation was selected under section 2.2.5(c)(8) of this appendix, all conditionally valid data shall be invalidated, back to the first unit operating hour after the end of the calendar quarter for which E_f was above the applicable limit. Corrective actions shall be taken. All corrective actions (e.g., non-routine maintenance, repairs, major component replacements, re-linearization of the monitor, etc.) shall be documented in the operation and maintenance records for the monitor. The owner or operator then shall either complete the abbreviated flow-to-load test in section 2.2.5.3 of this appendix, or, if the corrective action taken has required relinearization of the flow monitor, shall perform a 3-load RATA. The conditional data validation procedures in § 75.20(b)(3) may be applied to the 3-load RATA.

2.2.5.2 Option 2

Perform a single-load RATA (at a load designated as normal under section 6.5.2.1 of appendix A to this part) of each flow monitor for which E_f is outside of the applicable limit. If the RATA is passed hands-off, in accordance with section 2.3.2(c) of this appendix, no further action is required and the out-of-control period for the monitor ends at the date and hour of completion of a successful RATA, unless the option to use conditional data validation was selected under section 2.2.5(c)(8) of this appendix. In that case, all conditionally valid data from the monitor are considered to be quality-assured, back to the first unit operating hour following the end of the calendar quarter for which the E_f value was above the applicable limit. If the RATA is failed, all data from the monitor shall be invalidated, back to the first unit operating hour following the end of the calendar quarter for which the E_f value was above the applicable limit. Data from the monitor remain invalid until the required RATA has been passed. Alternatively, following a failed RATA and corrective actions, the conditional data validation procedures of § 75.20(b)(3) may be used until the RATA has been passed. If the corrective actions taken following the failed RATA included adjustment of the polynomial coefficients or K-factor(s) of the flow monitor, a 3-level RATA is required.

2.2.5.3 Abbreviated Flow-to-Load Test

(a) * * * Data from the monitoring system are considered invalid from the hour of commencement of the repair, replacement, or maintenance until either the hour in which the abbreviated flow-to-load test is passed, or the hour in which a probationary calibration error test is passed following completion of the repair, replacement, or maintenance and any associated adjustments to the monitor. If the latter option is selected, the abbreviated flow-to-load test shall be completed within 168 cumulative unit operating hours of the probationary calibration error test (or, for peaking units, within 30 unit operating days, if that is less restrictive). * * *

* * * * *

2.3 Semiannual and Annual Assessments

* * * * *

2.3.1 Relative Accuracy Test Audit (RATA)

* * * * *

2.3.1.3 RATA Load (or Operating) Levels and Additional RATA Requirements

* * * * *

(c) * * *

(1) An annual 2-load (or 2-level) flow RATA shall be done at the two most frequently used load levels (or operating levels), as determined under section 6.5.2.1(d) of appendix A to this part. Alternatively, a 3-load (or 3-level) flow RATA at the low, mid, and high load levels (or operating levels), as defined under section 6.5.2.1(b) of appendix A to this part, may be performed in lieu of the 2-load (or 2-level) annual RATA.

(2) If the flow monitor is on a semiannual RATA frequency, 2-load (or 2-level) flow RATAs and single-load (or single-level) flow RATAs at the normal load level (or normal operating level) may be performed alternately.

(3) A single-load (or single-level) annual flow RATA may be performed in lieu of the 2-load (or 2-level) RATA if the results of an historical load data analysis show that in the time period extending from the ending date of the last annual flow RATA to a date that is no more than 21 days prior to the date of the current annual flow RATA, the unit (or combination of units, for a common stack) has operated at a single load level (or operating level) (low, mid, or high), for ≥85.0 percent of the time. Alternatively, a flow monitor may qualify for a single-load (or single-level) RATA if the 85.0 percent criterion is met in the time period extending from the beginning of the quarter in which the last annual flow RATA was performed through the end of the calendar quarter preceding the quarter of current annual flow RATA.

(4) A 3-load (or 3-level) RATA, at the low-, mid-, and high-load levels (or operating levels), as determined under section 6.5.2.1 of appendix A to this part, shall be performed at least once every five consecutive calendar years.

(5) A 3-load (or 3-level) RATA is required whenever a flow monitor is re-linearized, i.e., when its polynomial coefficients or K factor(s) are changed, except for flow monitors installed on peaking units and bypass stacks. For peaking units and bypass stacks, a single-load RATA at the normal load is required.

(6) For all multi-level flow audits, the audit points at adjacent load levels or at adjacent operating levels (e.g., mid and high) shall be separated by no less than 25.0 percent of the ''range of operation,'' as defined in section 6.5.2.1 of appendix A to this part.

* * * * *

2.3.2 Data Validation

* * * * *

(c) * * * If a routine daily calibration error test is performed and passed just prior to a RATA (or during a RATA test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the RATA test data. * * *

* * * * *

(e) For a RATA performed using the option in paragraph (b)(1) or (b)(2) of this section, if the RATA is failed (that is, if the relative accuracy exceeds the applicable specification in section 3.3 of appendix A to this part) or if the RATA is aborted prior to completion due to a problem with the CEMS, then the CEMS is out-of-control and all emission data from the CEMS are invalidated prospectively from the hour in which the RATA is failed or aborted. Data from the CEMS remain invalid until the hour of completion of a subsequent RATA that meets the applicable specification in section 3.3 of appendix A to this part. If 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, the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B). Note that when a RATA is aborted for a reason other than monitoring system malfunction (see paragraph (h) of this section), this does not trigger an out-of-control period for the monitoring system.

* * * * *

2.4 Recertification, Quality Assurance, RATA Frequency and Bias Adjustment Factors (Special Considerations)

* * * * *

(b) Except as provided in section 2.3.3 of this appendix, whenever a passing RATA of a gas monitor is performed, or a passing 2-load (or 2-level) RATA or a passing 3-load (or 3-level) RATA of a flow monitor is performed (irrespective of whether the RATA is done to satisfy a recertification requirement or to meet the quality assurance requirements of this appendix, or both), the RATA frequency (semi-annual or annual) shall be established based upon the date and time of completion of the RATA and the relative accuracy percentage obtained. For 2-load (or 2-level) and 3-load (or 3-level) flow RATAs, use the highest percentage relative accuracy at any of the loads (or levels) to determine the RATA frequency. The results of a single-load (or single-level) flow RATA may be used to establish the RATA frequency when the single-load flow RATA is specifically required under section 2.3.1.3(b) of this appendix (for flow monitors installed on peaking units and bypass stacks) or when the single-load (or single-level) RATA is allowed under section 2.3.1.3(c) of this appendix for a unit that has operated at one load level (or operating level) for ≥ 85.0 percent of the time since the last annual flow RATA. No other single-load (or single-level) flow RATA may be used to establish an annual RATA frequency; however, a 2-load or 3-load (or a 2-level or 3-level) flow RATA may be performed at any time or in place of any required single-load (or single-level) RATA, in order to establish an annual RATA frequency.

* * * * *

Figure 1 to Appendix B of Part 75—Quality Assurance Test Requirements

* * * * *

[2] For flow monitors installed on peaking units and bypass stacks, conduct all RATAs at a single, normal load. For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-level and 2-level RATAs may be done if a monitor is on a semiannual frequency. A single-level RATA may be done in lieu of a 2-level RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥ 85.0 percent of the time. A 3-level RATA is required at least once every five calendar years and whenever a flow monitor is re-linearized.

* * * * *

55. Appendix C to Part 75 is amended by:

a. Revising the section heading of section 2;

b. Revising the fifth sentence in section 2.2.1 and adding a new sentence after that fifth sentence;

c. Revising in section 2.2.3.9 the reference ''75.51(a)(2)'' to read ''75.71(a)(2)''; and

d. Adding new sections 3 and 4.

The revisions and additions read as follows:

Appendix C to Part 75—Missing Data Estimation Procedures

* * * * *

2. Load-Based Procedure for Missing Flow Rate, NO_X Concentration, and NO_X Emission Rate Data

* * * * *

2.2 Procedure

2.2.1 * * * For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity or for a unit for which hourly average gross load in MWge is not recorded separately, determine the maximum hourly average gross load for the unit by converting the maximum rated hourly unit heat input (including heat input from auxiliary firing, if applicable) to an equivalent gross megawatt value, using the percentage efficiencies of the main combustion source and (if applicable) any auxiliary combustion sources. If the actual percentage efficiency of a particular combustion source is unknown, use a default value of 50 percent for a combustion turbine and 33 percent for any other type of combustion source. * * *

* * * * *

3. Non-Load-Based Procedure for Missing Flow Rate, NO_X Concentration, and NO_X Emission Rate Data (Optional)

3.1 Applicability

For affected units that do not produce electrical output in megawatts or thermal output in klb/hr of steam, this procedure may be used in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh), NO_X emission rate (in lb/mmBtu) from NO_X-diluent continuous emission monitoring systems, and NO_X concentration data (in ppm) from NO_X concentration monitoring systems used to determine NO_X mass emissions.

3.2 Procedure

3.2.1 For each monitored parameter (flow rate, NO_X emission rate, or NO_X concentration), establish at least two, but no more than ten operational bins, corresponding to various operating conditions and parameters (or combinations of these) that affect volumetric flow rate or NO_X emissions. Include a complete description of each operational bin in the hardcopy portion of the monitoring plan required under § 75.53(e)(2), identifying the unique combination of parameters and operating conditions associated with the bin and explaining the relationship between these parameters and conditions and the magnitude of the stack gas flow rate or NO_X emissions. Assign a unique number, 1 through 10, to each operational bin. Examples of conditions and parameters that may be used to define operational bins include unit heat input, type of fuel combusted, specific stages of an industrial process, or (for common stacks), the particular combination of units that are in operation.

3.2.2 In the electronic quarterly report required under § 75.64, indicate for each hour of unit operation the operational bin associated with the NO_X or flow rate data, by recording the number assigned to the bin under section 3.2.1 of this appendix.

3.2.3 The data acquisition and handling system must be capable of properly identifying and recording the operational bin number for each unit operating hour. The DAHS must also be capable of calculating and recording the following information for each unit operating hour of missing flow or NO_X data within each identified operational bin during the shorter of: (a) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (b) all previous quality assured monitor operating hours:

3.2.3.1 Average of the hourly flow rates reported by a flow monitor (scfh).

3.2.3.2 The 90th percentile value of hourly flow rates (scfh).

3.2.3.3 The 95th percentile value of hourly flow rates (scfh).

3.2.3.4 The maximum value of hourly flow rates (scfh).

3.2.3.5 Average of the hourly NO_X emission rate, in lb/mmBtu, reported by a NO_X-diluent continuous emission monitoring system.

3.2.3.6 The 90th percentile value of hourly NO_X emission rates (lb/mmBtu).

3.2.3.7 The 95th percentile value of hourly NO_X emission rates (lb/mmBtu).

3.2.3.8 The maximum value of hourly NO_X emission rates, in (lb/mmBtu).

3.2.3.9 Average of the hourly NO_X pollutant concentrations (ppm), reported by a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.51(a)(2).

3.2.3.10 The 90th percentile value of hourly NO_X pollutant concentration (ppm).

3.2.3.11 The 95th percentile value of hourly NO_X pollutant concentration (ppm).

3.2.3.12 The maximum value of hourly NO_X pollutant concentration (ppm).

3.2.4 When a bias adjustment is necessary for the flow monitor and/or the NO_X-diluent continuous emission monitoring system (and/or the NO_X concentration monitoring system), apply the bias adjustment factor to all data values placed in the operational bins.

3.2.5 Calculate all CEMS data averages, maximum values, and percentile values determined by this procedure using bias-adjusted values.

3.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_X emission rate data (and where applicable, NO_X concentration data) according to the procedures in subpart D of this part.

4. Non-Load-Based Procedure for Missing Fuel Flowmeter Data (Optional)

4.1 Applicability

For affected units that do not produce electrical output in megawatts or thermal output in klb/hr of steam, this procedure may be used in accordance with the provisions of this part to provide substitute data for fuel flow rate.

4.2 Procedure

4.2.1 Establish at least two, but no more than ten operational bins, corresponding to various operating conditions and parameters (or combinations of these) related to the fuel flow rate. Include a complete description of each operational bin in the hardcopy portion of the monitoring plan required under § 75.53(f)(1)(ii), identifying the parameters and operating conditions associated with the bin and explaining the relationship between these parameters and conditions and the magnitude of the fuel flow rate. Assign a unique number, 1 through 10, to each operational bin.

4.2.2 In the electronic quarterly report required under § 75.64, indicate for each hour of unit operation the operational bin associated with the fuel flow rate data, by recording the number assigned to the bin under section 4.2.1 of this appendix.

4.2.3 The data acquisition and handling system (DAHS) must be capable of properly identifying and recording the operational bin number for each unit operating hour. The DAHS must also be capable of calculating and recording the following information for each unit operating hour of missing fuel flow rate data within each identified operational bin during the previous 720 operating hours (on a rolling basis):

4.2.3.1 Arithmetic average of the hourly fuel flow rates reported by a certified fuel flowmeter system, in appropriate units of fuel flow rate.

4.2.3.2 The maximum value of hourly fuel flow rates reported by a certified fuel flowmeter system, in appropriate units of fuel flow rate.

4.2.4 The DAHS shall also be capable of separating the recorded fuel flow rate data on the basis of the type of fuel combusted in the unit. A separate database shall be created and maintained for each type of fuel when it is combusted alone in the unit. If different types of fuel are co-fired in the unit, an additional database shall be created and maintained for each type of fuel, for hours in which it is co-fired with any other type(s) of fuel(s).

4.3 Use the calculated average and maximum values to substitute for missing fuel flow rate data according to the applicable procedures in sections 2.4.2 and 2.4.3 in appendix D to this part.

Appendix D Section 1 [Amended].

56. Section 1 of Appendix D to Part 75 is amended by removing the final sentence of section 1.2.

57. Section 2 of Appendix D to Part 75 is amended by:

a. Revising sections 2.1.2, 2.1.2.1, and 2.1.2.2;

b. Revising the first sentence of section 2.1.4.1;

c. Revising section 2.1.4.3;

d. In section 2.1.5 by revising the words ''calibrated fuel flow rate'' to read ''fuel flow rate measurable by the flowmeter'' in the first sentence, by adding the words ''(orifice, nozzle, and venturi-type flowmeters, only)'' after the words ''by design'' in the second sentence, and by revising the words ''measurement against a NIST-traceable reference method'' in the third sentence to read ''in-line comparison against a reference flowmeter'';

e. In section 2.1.5.4 by revising the words ''using the following'' to read ''in a manner consistent with'';

f. In paragraph (c) of section 2.1.6 by removing the words ''2.1.5.1 or'';

g. In paragraph (d) of section 2.1.6 by removing the words '', where applicable,'' before the words ''those procedures'' and '', where applicable'' after the second occurrence of the words ''element inspection'', and by adding ''(if applicable)'' after both occurrences of the words ''test or'';

h. Adding new paragraphs (e) and (f) to section 2.1.6;

i. In the second sentence of paragraph (a) of section 2.1.6.1 by adding the word ''upscale'' after the word ''other'' and by adding a new third sentence;

j. In section heading 2.1.6.2 by revising the words ''and Reporting of'' to read ''for'';

k. In paragraph (a) of section 2.1.6.2 by removing the second and third sentences;

l. Removing and reserving sections 2.1.6.2(b) and 2.1.6.2(c);

m. In the final sentence of section 2.1.6.3 by removing the words ''§ 75.56 or'' and '', as applicable'';

n. In the fourth sentence of paragraph (a) of section 2.1.6.4 by revising the words ''indicates that'' to read ''is failed (if'' and by adding a closing parenthesis after the word ''corroded'';

o. In paragraph (a)(1) of section 2.1.6.4 by adding a new second sentence;

p. In paragraphs (a)(2) and (b)(2) of section 2.1.6.4 by revising the word ''under'' to read '', using'';

q. In paragraph (b) of section 2.1.6.4 by removing the first sentence;

r. In paragraph (b)(1) of section 2.1.6.4 by adding the words ''and, if applicable, the transmitters have been successfully recalibrated'' to the end of the final sentence;

s. In paragraph (c) of section 2.1.6.4 by revising the words ''this period'' to read ''each period of invalid fuel flowmeter data described in paragraph (b) of this section'';

t. In section 2.1.7 by removing each occurrence of the words ''where applicable,'' and ''as applicable,'', by removing the words ''§ 75.54(a) or'', and by adding the words ''(if applicable) a'' and ''(if applicable)'' after the two occurrences of ''test or'', respectively;

u. In paragraph (a) of section 2.1.7.1 by revising the first occurrence of ''i.e.'' to read ''e.g.'', by revising the sixth sentence, and by adding the word ''Arithmetic'' before the word ''average'' in the definitions of the variables ''Q_{base}'' and ''L_{avg}'' under Eq. D–1b;

v. Revising paragraph (b) of section 2.1.7.1;

w. In paragraph (c) of section 2.1.7.1 by adding the words ''average fuel flow rate and the fuel GCV in the'' before the word ''applicable'' in the definition of the variable ''$(\text{Heat Input})_{avg}$'' under Eq. D–1c;

x. In paragraph (a) of section 2.1.7.2 by adding a new third sentence;

y. Revising paragraph (b) of section 2.1.7.2;

z. In the variable for ''$(\text{Heat Input})_h$'' under Eq. D–1e in paragraph (c) of section 2.1.7.2 by adding the words ''hourly fuel flow rate and the fuel GCV in the'' after the words ''using the'';

aa. In paragraph (d) of section 2.1.7.2 by revising the third sentence and by adding a new fourth sentence;

bb. Revising the first sentence of paragraph (a) of section 2.1.7.3;

cc. Adding a second sentence to paragraph (b) of section 2.1.7.3;

dd. In the first sentence of paragraph (a) of section 2.1.7.4 by revising the reference to ''section 2.1.7.2'' to read ''section 2.1.7.2(h)'';

ee. In the final sentence of paragraph (b) of section 2.1.7.4 by adding the word ''fuel'' after the word ''two'' and by adding the words ''(as defined in § 72.2 of this chapter)'' after the word ''quarters'';

ff. Revising Table D–4 in section 2.2;

gg. In section 2.2.4.2 introductory text by adding the words ''and GCV value'' after the words ''Use the sulfur content'' in the fourth sentence, and by revising the reference to ''section 2.2.4.3'' to read ''section 2.2.4.3(c)'';

hh. Revising paragraph (b) of section 2.2.4.2;

ii. In the second sentence of paragraph (c) of section 2.2.4.3 by revising the first and second occurrences of the words ''two following values'' with, respectively, the words ''following conservative, assumed values'' and ''assumed values'';

jj. Revising paragraph (d) of section 2.2.4.3;

kk. Revising Table D–5 in section 2.3(b);

ll. Revising all of section 2.3.1.4 except for the section heading and paragraph (a)(1);

mm. In section 2.3.2.1.1 by adding a new second sentence and by revising Equation D–1h and the definitions of variables for Equation D–1h;

nn. Revising sections 2.3.2.1.2 and 2.3.2.4;

oo. In section 2.3.3.2 by revising the third sentence and adding a new fourth sentence;

pp. In section 2.3.4.3 by adding a new second sentence;

qq. Revising the fourth sentence of section 2.3.4.3.1;

rr. Revising section 2.3.4.3.2 and paragraph (a) of section 2.3.5;

ss. In paragraph (a) of section 2.3.6 by revising the first, second, fourth, and fifth sentences and by adding a new sentence after the second sentence;

tt. In the first sentence of paragraph (b) of section 2.3.6 by removing the words ''(and hydrogen sulfide content, if applicable)'';

uu. In the first sentence of section 2.4.1 by removing the reference ''2.3.3.1.2,'';

vv. Revising Table D–6 in section 2.4.1 and sections 2.4.2, 2.4.2.1(b) and heading, 2.4.2.2, and 2.4.2.3; and

ww. In section 2.4.3 by adding a new sentence to the end of that section.

The revisions and additions read as follows:

2. Procedure

2.1 Fuel Flowmeter Measurements

* * * * *

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (as defined in § 72.2 of this chapter). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix shall not apply to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_X mass emissions under a state or federal NO_X mass emission reduction program, unless both of the following are true: all of the units served by the common pipe are affected units, and all of the units have similar efficiencies. For the purposes of this section, units served by a common pipe have similar efficiencies (e.g., if all of the units are boilers or if all of the units are combustion turbines). When a fuel flowmeter is installed in a common pipe header, proceed as follows:

2.1.2.1 Measure the fuel flow rate in the common pipe, and combine SO_2 mass emissions (Acid Rain Program units only) for the affected units for recordkeeping and compliance purposes; and

2.1.2.2 Apportion the heat input rate measured at the common pipe to the individual units, using Equation F–21a, F–21b, or F–21d in appendix F to this part.

* * * * *

2.1.4 Situations in Which Certified Flowmeter Is Not Required

2.1.4.1 Start-up or Ignition Fuel

For an oil-fired unit that uses gas solely for start-up or burner ignition, a gas-fired unit that uses oil solely for start-up or burner ignition, or an oil-fired unit that uses a different grade of oil solely for start-up or burner ignition, a fuel flowmeter for the start-up fuel is permitted but not required. * * *

* * * * *

2.1.4.3 Emergency Fuel

The designated representative of a unit that is restricted by a federally-enforceable permit to combusting a particular fuel only during emergencies where the primary fuel is not available is exempt from certifying a fuel flowmeter for use during combustion of the emergency fuel. During any hour in which the emergency fuel is combusted, report the hourly heat input to be the maximum rated heat input of the unit for the fuel. Use the maximum potential sulfur content for the fuel (from Table D–6 of this appendix) and the fuel flow rate corresponding to the maximum hourly heat input to calculate the hourly SO_2 mass emission rate, using Equations D–2 through D–4 of this appendix (as applicable). Alternatively, if a certified fuel flowmeter is available for the emergency fuel, you may use the measured hourly fuel flow rates in the calculations. Also, if daily samples or weekly composite samples (fuel oil, only) of the fuel's total sulfur content, GCV, and (if applicable) density are taken during the combustion of the emergency fuel, as described in section 2.2 or 2.3 of this appendix, the sample results may be used to calculate the hourly SO_2 emissions and heat input rates, in lieu of using maximum potential values. The designated representative shall also provide notice under § 75.61(a)(6) for each period when the emergency fuel is combusted.

* * * * *

2.1.6 Quality Assurance

* * * * *

(e) When accuracy testing of the orifice, nozzle, or venturi meter is performed according to section 2.1.5.2 of this appendix, record the information displayed in Table D–1 in this section. At a minimum, record the overall accuracy results for the fuel flowmeter at the three flow rate levels specified in section 2.1.5.2 of this appendix.

(f) Report the results of all fuel flowmeter accuracy tests, transmitter or transducer accuracy tests, and primary element inspections, as applicable, in the emissions report for the quarter in which the quality assurance tests are performed, using the electronic format specified by the Administrator under § 75.64.

2.1.6.1 Transmitter or Transducer Accuracy Test for Orifice-, Nozzle-, and Venturi-Type Flowmeters

(a) * * * For temperature transmitters, the zero and upscale levels may correspond to fixed reference points, such as the freezing point or boiling point of water.

* * * * *

2.1.6.4 Primary Element Inspection

(a) * * *

(1) * * * If the primary element size is changed, also calibrate the transmitters or transducers, consistent with the new primary element size;

* * * * *

2.1.7 Fuel Flow-to-Load Quality Assurance Testing for Certified Fuel Flowmeters

* * * * *

2.1.7.1 Baseline Flow Rate-to-Load Ratio or Heat Input-to-Load Ratio

(a) * * * For orifice-, nozzle-, and venturi-type fuel flowmeters, if the fuel flow-to-load ratio is to be used as a supplement both to the transmitter accuracy test under section 2.1.6.1 of this appendix and to primary element inspections under section 2.1.6.4 of this appendix, then the baseline data must be obtained after both procedures are completed and no later than the end of the fourth calendar quarter following the calendar quarter in which both procedures were completed. * * *

* * * * *

(b) In Equation D–1b, for a fuel flowmeter installed on a common pipe header, L_{avg} is the sum of the operating loads of all units that received fuel through the common pipe header during the baseline period, divided by the total number of hours of fuel flow rate data collected during the baseline period. For a unit that receives the same type of fuel through multiple pipes, Q_{base} is the sum of the fuel flow rates during the baseline period from all of the pipes, divided by the total number of hours of fuel flow rate data collected during the baseline period. Round off the value of R_{base} to the nearest tenth.

* * * * *

2.1.7.2 Data Preparation and Analysis

(a) * * * Alternatively, the owner or operator may exclude non-representative hours from the data analysis, as described in section 2.1.7.3 of this appendix, prior to calculating the values of R_h.

* * * * *

(b) For a fuel flowmeter installed on a common pipe header, L_h shall be the sum of the hourly operating loads of all units that receive fuel through the common pipe header. For a unit that receives the same type of fuel through multiple pipes, Q_h will be the sum of the fuel flow rates from all of the pipes. Round off each value of R_h to the nearest tenth.

* * * * *

(d) * * * If, for a particular fuel flowmeter, fewer than 168 hourly flow-to-load ratios (or GHR values) are available, or, if the baseline data collection period is still in progress at the end of the quarter and fewer than four calendar quarters have elapsed since the quarter in which the last successful fuel flowmeter accuracy test was performed, a flow-to-load (or GHR) evaluation is not required for that flowmeter for that calendar quarter. A one-quarter extension of the deadline for the next fuel flowmeter accuracy test may be claimed for a quarter in which there is insufficient hourly data available to analyze or a quarter that ends with the baseline data collection period still in progress.

* * * * *

2.1.7.3 Optional Data Exclusions

(a) If E_f is outside the limits in section 2.1.7.2(h) of this appendix, the owner or operator may re-examine the hourly fuel flow rate-to-load ratios (or GHRs) that were used for the data analysis and may identify and exclude fuel flow-to-load ratios or GHR values for any non-representative hours, provided that such data exclusions were not previously made under section 2.1.7.2(a) of this appendix. * * *

(b) * * * If fewer than 168 hourly fuel flow-to-load ratio or GHR values remain after the allowable data exclusions, a fuel flow-to-load ratio or GHR analysis is not required for that quarter, and a one-quarter extension of the fuel flowmeter accuracy test deadline may be claimed.

* * * * *

2.2 Oil Sampling and Analysis

* * * * *

TABLE D–4.—OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations
Oil Sulfur Content	Daily manual sampling	1. Highest sulfur content from previous 30 daily samples; or 2. Actual daily value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; [1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; [1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
Oil Density	Daily manual sampling	1. Use the highest density from the previous 30 daily samples; or 2. Actual measured value.

TABLE D–4.—OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS—Continued

Parameter	Sampling technique/frequency	Value used in calculations
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; [1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; [1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
Oil GCV	Daily manual sampling	1. Highest fuel GCV from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; [1] or 3. Maximum value allowed by contract, unless a higher sample value is obtained.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year, unless a higher sample value is obtained; [1] or 2. Maximum value allowed by contract, unless a higher sample value is obtained.[1]

[1] Assumed values may only be used if sulfur content, gross calorific value, or density of each sample is no greater than the assumed value used to calculate emissions or heat input. If a higher sample value is obtained, use the results of that sample analysis as the new assumed value.

* * * * *

2.2.4 Manual Sampling

* * * * *

2.2.4.2 Sampling from a Unit's Storage Tank

* * * * *

(b) One of the conservative assumed values described in section 2.2.4.3(c) of this appendix. Follow the applicable provisions in section 2.2.4.3(d) of this appendix, regarding the use of assumed values.

2.2.4.3 Sampling from Each Delivery

* * * * *

(d) Continue using the assumed value(s), so long as the sample results do not exceed the assumed value(s). However, if the actual sampled sulfur content, gross calorific value, or density of an oil sample is greater than the assumed value for that parameter, then, beginning on the date of receipt of the results of the sample analysis, use the actual sampled value for sulfur content, gross calorific value, or density of fuel to calculate SO_2 mass emission rate or heat input rate. Consider the sampled value to be the new assumed sulfur content, gross calorific value, or density. Continue using this new assumed value to calculate SO_2 mass emission rate or heat input rate unless and until: it is superseded by a higher value from an oil sample; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.3 SO_2 Emissions from Combustion of Gaseous Fuels

* * * * *

TABLE D–5.—GAS SULFUR AND GCV VALUES USED IN CALCULATIONS FOR VARIOUS FUEL TYPES

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
Gas Sulfur Content	Pipeline Natural Gas with total sulfur content less than or equal to 0.5 grains/100scf (when using the provisions of section 2.3.1 to determine SO_2 mass emissions)—Sample semiannually and whenever fuel composition changes significantly.	0.0006 lb/mmBtu.
	Natural Gas with total sulfur content less than or equal to 20.0 grains/100scf (when using the provisions of section 2.3.2 to determine SO_2 mass emissions)—Sample semiannually and whenever fuel composition changes significantly.	Default SO_2 emission rate calculated from Eq. D–1h, using either: 1. The fuel contract maximum total sulfur content, unless a higher value is obtained in a semiannual sample;[1] 2. The maximum total sulfur content from the previous year's samples, unless a higher value is obtained in a semiannual sample;[1] or 3. The actual total sulfur content from the most recent semiannual sample.

TABLE D–5.—GAS SULFUR AND GCV VALUES USED IN CALCULATIONS FOR VARIOUS FUEL TYPES—Continued

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
	Any gaseous fuel delivered in shipments or lots—Sample each lot or shipment.	1. Actual total sulfur content from most recent shipment; 2. Highest total sulfur content from previous year's samples, unless a higher value is obtained in a sample;[1] or 3. Maximum total sulfur content value allowed by contract, unless a higher value is obtained in a sample.[1]
	Any gaseous fuel transmitted by pipeline and having a demonstrated ''low sulfur variability'' using the provisions of section 2.3.6—Sample daily.	1. Actual total sulfur content from daily sample; or 2. Highest total sulfur content from previous 30 daily samples.
	Any gaseous fuel—Sample hourly	Actual hourly total sulfur content of the gas.
Gas GCV	Pipeline Natural Gas—Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); 2. Maximum GCV from contract, unless a higher value is obtained in a monthly sample;[1] or 3. Highest GCV from previous year's samples, unless a higher value is obtained in a monthly sample.[1]
	Natural Gas—Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); 2. Maximum GCV from contract;[1] or 3. Highest GCV from previous year's samples.[1]
	Any gaseous fuel delivered in shipments or lots—Sample each lot or shipment.	1. Actual GCV from most recent shipment or lot; 2. Highest GCV from previous year's samples, unless a higher value is obtained in a sample;[1] or 3. Maximum GCV value allowed by contract, unless a higher value is obtained in a sample.[1]
	Any gaseous fuel transmitted by pipeline and having a demonstrated ''low GCV variability'' using the provisions of section 2.3.5—Sample monthly.	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); or 2. Highest GCV from previous year's samples, unless a higher value is obtained in a monthly sample.[1]
	Any other gaseous fuel not having a ''low GCV variability''—Sample daily or hourly. (Note that the use of an on-line GCV calorimeter or gas chromatograph is allowed).	Actual daily or hourly GCV of the gas.

[1] Assumed sulfur content and GCV values (i.e., contract values or highest values from previous year) may only continue to be used if the sulfur content or GCV of each sample is no greater than the assumed value used to calculate SO_2 emissions or heat input. If a higher sample value is obtained, use the results of that sample analysis as the new assumed value.

2.3.1 Pipeline Natural Gas Combustion

* * * * *

2.3.1.4 Documentation that a Fuel is Pipeline Natural Gas

(a) A fuel may initially qualify as pipeline natural gas, if information is provided in the monitoring plan required under § 75.53, demonstrating that the definition of pipeline natural gas in § 72.2 of this chapter has been met. The information must demonstrate that the fuel meets either the percent methane or GCV requirement and has a total sulfur content of less than or equal to 0.5 grains/100scf. The demonstration must be made using one of the following sources of information:

* * * * *

(2) The results of all available fuel sample analyses from the past 12 months, documenting the total sulfur content of the fuel and the percentage by weight of methane and/or GCV of the fuel. The fuel samples may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the supplier of the gaseous fuel;

(3) Data from a 720-hour demonstration conducted using the procedures of sections 2.3.5 and 2.3.6 of this appendix, documenting the total sulfur content of the fuel and the percentage by weight of methane and/or the GCV of the fuel, and using comparable procedures to document the percentage by weight of methane; or

(4) If historical fuel sampling results or data from a 720-hour demonstration are not available, a fuel may initially qualify as pipeline natural gas if a sample of the fuel is obtained and analyzed for total sulfur content and for percent methane or GCV, and if the results of the sample analysis show that the total sulfur content and percentage methane or GCV meet the definition of pipeline natural gas in § 72.2 of this chapter.

(b) After a fuel initially qualifies as pipeline natural gas under paragraph (a) of this section, the owner or operator shall sample the fuel for total sulfur content at least semiannually and whenever it is reasonable to believe that the fuel composition has changed significantly. The owner or operator shall also sample the GCV of the fuel at the frequency specified in section 2.3.4.1 of this appendix.

(c) If the results of a sample under paragraph (b) of this section show that the total sulfur content of the fuel exceeds 0.5gr/100 scf, the fuel no longer qualifies as pipeline natural gas. When this occurs:

(1) If the sample results show that the fuel still qualifies as natural gas under section 2.3.2.4 of this appendix, discontinue using the 0.0006 lb/mmBtu default SO_2 emission rate under 2.3.1.1, as of the date on which the sample results are received. Determine a new default SO_2 emission rate according to section 2.3.2.1.1 of this appendix and use the new SO_2 emission rate, beginning with the date of receipt of the sample results; or

(2) If the sample results show that the fuel no longer qualifies either as pipeline natural gas or natural gas, the owner or operator shall implement the procedures of section 2.3.3.1 of this appendix (for sulfur content determination) and section 2.3.4.3 of this appendix (for GCV determination), no later than 90 days after the end of the quarter in which the sample results are received.

2.3.2 Natural Gas Combustion

* * * * *

2.3.2.1 SO_2 Emission Rate

* * * * *

2.3.2.1.1 * * * In Equation D–1h, the total sulfur content and GCV values shall be determined in accordance with the allowable options shown in Table D–5 of this appendix. * * *

$$ER = \left[\frac{2.0}{7000}\right] \times \left[10^6\right] \times \left[\frac{S_{total}}{GCV}\right] \qquad (\text{Eq. D}-1\text{h})$$

Where:

ER = Default SO_2 emission rate for natural gas combustion, lb/mmBtu.

S_{total} = Total sulfur content of the natural gas, gr/100scf.

GCV = Gross calorific value of the natural gas, Btu/100scf.

7000 = Conversion of grains/100scf to lb/100scf.

2.0 = Ratio of lb SO_2/lb S.

10^6 = Conversion factor (Btu/mmBtu).

2.3.2.1.2 For reporting purposes, apply the results of the required periodic fuel samples described in Table D–5 of this appendix as follows. Use Equation D–1h to recalculate the SO_2 emission rate, as necessary.

(a) For daily samples of total sulfur content or GCV:

(1) If the actual value is to be used in the calculations, apply the results of each daily sample to all hours in the day on which the sample is taken; or

(2) If the highest value in the previous 30 daily samples is to be used in the calculations, apply that value to all hours in the current day. If, for a particular unit, fewer than 30 daily samples have been collected, use the highest value from all available samples until 30 days of historical sampling results have been obtained.

(b) For semiannual samples of total sulfur content:

(1) If the actual value is to be used in the calculations, apply the results of the most recent sample, until the date on which the results of the next sample are received; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value to all hours in the quarter unless a higher value is obtained in a semiannual fuel sample. In that case, use the sampled value, beginning with the date of receipt of the sample results. Consider the sample results to be the new assumed value. Continue using the new assumed value unless and until it is superseded by a higher value from a subsequent quarterly sample; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

(c) For monthly samples of the fuel GCV:

(1) If the actual value is to be used in the calculations, apply the results of the most recent sample, until the date on which the results of the next sample are received; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value to all hours in each month of the quarter unless a higher value is obtained in a monthly GCV sample. In that case, use the sampled value, beginning with the date of receipt of the sample results. Consider the sample results to be the new assumed value. Continue using the new assumed value unless and until it is superseded by a higher value from a subsequent monthly sample; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

(d) For samples of gaseous fuel delivered in shipments or lots:

(1) If the actual value for the most recent shipment is to be used in the calculations, apply the results of the most recent sample, until the date on which the results of the next sample are received; or

(2) If an assumed value (contract maximum or highest value from previous year's samples) is to be used in the calculations, apply the assumed value unless a higher value is obtained in a sample of a shipment. In that case, use the sampled value, beginning with the date of receipt of the sample results. Consider the sample results to be the new assumed value. Continue using the new assumed value unless and until: it is superseded by a higher value from a sample of a subsequent shipment; or (if applicable) it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

* * * * *

2.3.2.4 Documentation that a Fuel is a Natural Gas

(a) A fuel may initially qualify as natural gas if information is provided in the monitoring plan required under § 75.53, demonstrating that the definition of natural gas in § 72.2 of this chapter has been met. The information must demonstrate that the fuel meets either the percent methane or GCV requirement and has a total sulfur content of less than or equal to 20.0 grains/100 scf. This demonstration must be made using one of the following sources of information:

(1) The gas quality characteristics specified by a purchase contract or by a transportation contract;

(2) The results of all available fuel sample analyses from the past 12 months, documenting the total sulfur content of the fuel and the percentage by weight of methane and/or GCV of the fuel. The fuel samples may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the supplier of the gaseous fuel;

(3) Data from a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix, documenting the total sulfur content of the fuel and the percentage by weight of methane and/or the GCV of the fuel, and using comparable procedures to document the percentage by weight of methane; or

(4) If historical fuel sampling results or data from a 720-hour demonstration are not available, a fuel may initially qualify as natural gas if a sample of the fuel is obtained and analyzed for total sulfur content and for percent methane or GCV, and if the results of the sample analyses show that the total sulfur content and percentage methane or GCV meet the definition of natural gas in § 72.2 of this chapter.

(b) After a fuel initially qualifies as natural gas under paragraph (a) of this section, the owner or operator shall sample the fuel for total sulfur content at least semiannually and whenever it is reasonable to believe that the fuel composition has changed significantly. The owner or operator shall also sample the GCV of the fuel at the frequency specified in section 2.3.4.2 of this appendix.

(c) If the results of a periodic sample required under paragraph (b) of this section show that the total sulfur content of the fuel exceeds 20.0 gr/100 scf, the fuel no longer qualifies as natural gas. In that case, the owner or operator shall implement the procedures of section 2.3.3.1 of this appendix (for sulfur content determination) and section 2.3.4.3 of this appendix (for GCV determination), no later than 90 days after the end of the quarter in which the sample results are received.

2.3.3 SO_2 Mass Emissions From Any Gaseous Fuel

* * * * *

2.3.3.2 SO_2 Mass Emission Rate

* * * That is, for fuels delivered by pipeline which demonstrate a low sulfur variability (under section 2.3.6 of this appendix) use either the daily sample value or the highest value in the previous 30 daily samples or for fuels requiring hourly sulfur content sampling with a gas chromatograph use the actual hourly sulfur content). For fuels delivered in shipments or lots, use either the actual sulfur content from the most recent shipment or an assumed value (contract maximum or highest value from the previous year's samples). In all cases, for reporting purposes, apply the results of the required periodic total sulfur samples in accordance with the provisions of section 2.3.2.1.2 of this appendix.

* * * * *

2.3.4 Gross Calorific Values for Gaseous Fuels

* * * * *

2.3.4.3 GCV of Other Gaseous Fuels

* * * For reporting purposes, apply the results of the required periodic GCV samples in accordance with the provisions of section 2.3.2.1.2 of this appendix.

2.3.4.3.1 * * * For sampling from the tank after each delivery, use either the most recent GCV sample, the maximum GCV specified in the fuel contract, or the highest GCV from the previous year's samples.

2.3.4.3.2 For any gaseous fuel that does not qualify as pipeline natural gas or natural gas, which is not delivered in shipments or lots, and which performs the required 720 hour test under section 2.3.5 of this appendix, if the results of the test demonstrate that the gaseous fuel has a low GCV variability, determine the GCV at least monthly. In calculations of hourly heat input for a unit, use either the most recent monthly sample, the maximum GCV specified in the fuel contract, or the highest fuel GCV from the previous year's samples.

* * * * *

2.3.5 Demonstration of Fuel GCV Variability

(a) This optional demonstration may be made for any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The demonstration data may be used to show that monthly sampling of the GCV of the gaseous fuel or blend is sufficient, in lieu of daily GCV sampling. The procedures in this section may also be used to demonstrate that the GCV of a particular gaseous fuel is within the range of GCV values for pipeline natural gas or natural gas, as defined in § 72.2 of this chapter.

* * * * *

2.3.6 Demonstration of Fuel Sulfur Variability

(a) This optional demonstration may be made for any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The results of the demonstration may be used to show that daily sampling for sulfur in the fuel is sufficient, rather than hourly sampling. The procedures in this section may also be used to demonstrate that the total sulfur content of a particular gaseous fuel is within the limits for pipeline natural gas or natural gas, as defined in § 72.2 of this chapter. * * * Provide a minimum of 720 hours of data, indicating the total sulfur content of the gaseous fuel or blend (in gr/100 scf). The demonstration data shall be obtained using either manual hourly sampling or an on-line gas chromatograph capable of determining fuel total sulfur content on an hourly basis. * * *

* * * * *

2.4 Missing Data Procedures

* * * * *

2.4.1 Missing Data for Oil and Gas Samples

* * * * *

TABLE D–6.—MISSING DATA SUBSTITUTION PROCEDURES FOR SULFUR, DENSITY, AND GROSS CALORIFIC VALUE DATA

Parameter	Missing data substitution maximum potential value
Oil Sulfur Content	3.5 percent for residual oil, or 1.0 percent for diesel fuel.
Oil Density	8.5 lb/gal for residual oil, or 7.4 lb/gal for diesel fuel.
Oil GCV	19,500 Btu/lb for residual oil, or 20,000 Btu/lb for diesel fuel.
Gas Total Sulfur Content	1. 0.002 lb/mmBtu for pipeline natural gas; 2. For natural gas for which semiannual sampling is performed, a default emission rate calculated from Equation D–1h, using the lesser of: (a) The maximum total sulfur content specified in the fuel contract; or (b) 1.5 times the highest total sulfur content from the previous year's samples; 3. For any gaseous fuel sampled daily, 1.5 times the highest total sulfur content value from the previous 30 days on which valid samples were obtained; or 4. For any gaseous fuel sampled hourly, the highest total sulfur content value from the previous 720 hourly samples
Gas GCV/Heat Content	1100 Btu/scf for pipeline natural gas, natural gas or landfill gas. 1500 for butane or refinery gas. 2100 Btu/scf for propane or any other gaseous fuel.

2.4.2 *Missing Data Procedures for Fuel Flow Rate.* Whenever data are missing from any primary fuel flowmeter system (as defined in § 72.2 of this chapter) and there is no backup system available to record the fuel flow rate, use the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix to account for the flow rate of fuel combusted at the unit for each hour during the missing data period. Alternatively, for a fuel flowmeter system used to measure the fuel combusted by a peaking unit, the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix may be used. Before using the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix, establish load ranges for the unit using the procedures of section 2 in appendix C to this part, except for units that do not produce electrical output (megawatts) or thermal output (e.g., klb of steam per hour). The owner or operator of a unit that does not produce electrical or thermal output may either establish operational bins for the unit, as described in section 4 of appendix C to this part, or may perform missing data substitution without segregating the fuel flow rate data into bins. When load ranges or operational bins are used for fuel flow rate missing data purposes, separate, fuel-specific databases shall be created and maintained. A database shall be kept for each type of fuel combusted in the unit, for the hours in which the fuel is combusted alone in the unit. An additional database shall be kept for each type of fuel, for the hours in which it is co-fired with any other type(s) of fuel(s).

2.4.2.1 Simplified Fuel Flow Rate Missing Data Procedure for Peaking Units * * *

(b) The maximum flow rate that the fuel flowmeter can measure (i.e, the upper range value of the flowmeter).

2.4.2.2 *Missing Data Procedures for Non-peaking Units—Single Fuel Hours.* For missing data periods that occur when only one type of fuel is being combusted, provide substitute data for each hour in the missing data period as follows.

2.4.2.2.1 If load-based missing data procedures are used, substitute the arithmetic average of the hourly fuel flow rate(s) measured and recorded by a certified fuel flowmeter system at the corresponding operating unit load range during the previous 720 operating hours in which the unit combusted only that same fuel. If no fuel flow rate data are available at the corresponding load range, apply the same mathematical algorithm to, and use the same lookback period for, the data from the next higher load range, if such data are available. If no quality-assured fuel flow rate data are available at either the corresponding load range or a higher load range, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.2.2 For units that do not produce electrical or thermal output and therefore cannot use load-based missing data procedures, provide substitute data for each hour of the missing data period as follows.

2.4.2.2.2.1 If operational bins (as defined in section 4 of appendix C to this part) are used, substitute the arithmetic average of the hourly fuel flow rates measured and recorded by a certified fuel flowmeter system at the corresponding operational bin during the previous 720 operating hours in which the unit combusted only that same fuel. If no quality-assured fuel flow rate data are available at the corresponding operational bin, or, if essential operating or parametric data are unavailable and the operational bin cannot be determined, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.2.2.2 If operational bins are not used, substitute the arithmetic average of the hourly fuel flow rates measured and recorded by a certified fuel flowmeter system during the previous 720 operating hours in which the unit combusted only that same fuel. If no quality-assured fuel flow rate data are available, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1

of this appendix) for each hour of the missing data period.

2.4.2.3 *Missing Data Procedures for Non-peaking Units—Multiple Fuel Hours.* For missing data periods that occur when two or more different types of fuel are being co-fired, provide substitute fuel flow rate data for each hour of the missing data period as follows.

2.4.2.3.1 If load-based missing data procedures are used, substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system at the corresponding load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If no such quality-assured fuel flow rate data are available at the corresponding load range, apply the same mathematical algorithm to, and use the same lookback period for, the data from the next higher load range (if available). If no quality-assured fuel flow rate data are available for co-fired hours, either at the corresponding load range or a higher load range, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.2 For units that do not produce electrical or thermal output and therefore cannot use load-based missing data procedures, provide substitute fuel flow rate data for each hour of the missing data period as follows.

2.4.2.3.2.1 If operational bins (as defined in section 4 of appendix C to this part) are used, substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system at the corresponding operational bin, during the previous 720 operating hours in which the unit for which the flow rate data are missing was co-fired with any other type of fuel. If no quality-assured fuel flow rate data for co-fired hours are available at the corresponding operational bin, or, if essential operating or parametric data are unavailable and the operational bin cannot be determined, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.2.2 If operational bins are not used, substitute the maximum hourly fuel flow rate measured and recorded by a certified fuel flowmeter system during the previous 720 operating hours in which the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If no quality-assured fuel flow rate data for co-fired hours are available, substitute the maximum potential fuel flow rate (as defined in section 2.4.2.1 of this appendix) for each hour of the missing data period.

2.4.2.3.3 If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in section 2.4.2.3.1 or 2.4.2.3.2 of this appendix (as applicable) separately for each type of fuel.

2.4.2.3.4 If the missing data substitution required in section 2.4.2.3.1 or 2.4.2.3.2 causes the reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit's maximum rated hourly heat input. Manual entry of the adjusted substitute data values is permitted.

2.4.3 * * * In addition, if there is at least one hour, but fewer than 720 hours of quality-assured fuel flowmeter data available for the lookback periods described in sections 2.4.2.2 and 2.4.2.3 of this appendix, use all of the available fuel flowmeter data to determine the appropriate substitute data values.

Appendix D to Part 75 [Amended]

58. Section 3 of Appendix D to Part 75 is amended by:

a. In the definition of the variable ''$\%S_{oil}$'' in Equation D–2 in section 3.1.1 by removing the word ''measured'', and by revising the word ''sample'' to read ''oil'';

b. In the numerator of Equation D–4 in section 3.3.1 by revising the number ''2'' with the number ''2.0'';

c. In the definition of the variable ''GCV_{gas}'' in Equation D–6 in section 3.4.1 by revising the word ''Btu/hr'' to read ''Btu/100 scf'';

d. In the definition of the variable ''GCV_{oil}'' in Equation D–8 in section 3.4.2 by adding the word ''or'' after the word ''Btu/ton,'';

e. In paragraph (b) in section 3.4.3 by revising the words ''Equation D–10 or D–11'' to read ''Equation F–21a or F–21b in appendix F to this part'' in the third sentence and by removing equations and variable definitions for Equations D–10 and D–11;

f. In paragraph (c) of section 3.4.3 by revising the words ''Equation D–10 or D–11'' to read ''Equation F–21a or F–21b'';

g. Revising the section heading of section 3.5;

h. In section heading 3.5.4 by adding the words ''Rate and Heat Input'' after the word ''Input''; and

i. In section 3.5.4 by adding the subsection number ''3.5.4.1'' before the existing text of the section and adding new subsection 3.5.4.2 following the variable definitions for Equation D–15.

The revisions and additions read as follows:

3. Calculations

* * * * *

3.5 Conversion of Hourly Rates to Hourly, Quarterly, and Year-to-Date Totals

* * * * *

3.5.4 Hourly Total Heat Input Rate and Heat Input from the Combustion of all Fuels

* * * * *

3.5.4.2 For reporting purposes, determine the heat input rate to each unit, in mmBtu/hr, for each hour from the combustion of all fuels using Equation D–15a:

$$HI_{rate\text{-}hr} = \frac{\sum_{all\text{-}fuels} HI_{rate\text{-}i} t_i}{t_u} \qquad \text{(Eq. D–15a)}$$

Where:

$HI_{rate\text{-}hr}$ = Total heat input rate from all fuels combusted during the hour, mmBtu/hr.

$HI_{rate\text{-}i}$ = Heat input rate for each type of gas or oil combusted during the hour, mmBtu/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_u = Unit operating time

* * * * *

59. Section 1 of Appendix E to Part 75 is amended by revising the second sentence of section 1.1 and adding two sentences after that second sentence to read as follows:

Appendix E to Part 75—Optional NO_X Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

1. Applicability

1.1 Unit Operation Requirements

* * * If a unit's operations exceed the levels required to be a peaking unit, the owner or operator shall install and certify a NO_X-diluent continuous emission monitoring system no later than December 31 of the following calendar year. If the required CEMS has not been installed and certified by that date, the owner or operator shall report the maximum potential NO_X emission rate (MER) (as defined in § 72.2 of this chapter) for each unit operating hour, starting with the first unit operating hour after the deadline and continuing until the CEMS has been provisionally certified. For each unit operating hour in which the MER is reported, the MER shall be specific to the type of fuel being combusted in the unit. * * *

* * * * *

60. Section 2 of Appendix E to Part 75 is amended by:

a. Revising sections 2.1.4, 2.2 and 2.5.2;

b. In the second sentence of section 2.1.5 by revising the words ''nearest 0.01 lb/mm/Btu'' to read ''nearest 0.001 lb/mmBtu'';

c. In section 2.3 by revising the words ''10 unit'' to read ''30 unit'' and the words ''section 2.1 of appendix B of this part'' with ''§ 72.2 of this chapter,'' and by revising the reference to ''§ 75.60(a)'' to read ''§ 75.60'';

d. In sections 2.3.1 and 2.3.2 by revising the first sentence of each section, adding a new sentence after each first sentence, and revising each occurrence of the words ''manufacturer's recommended'' to read ''acceptable'';

e. Revising the third sentence of 2.4.2;

f. Adding a new second sentence in section 2.5; and

g. Adding sections 2.5.2.1, 2.5.2.1.1, 2.5.2.1.2, 2.5.2.2, and 2.5.2.3.

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. Procedure

2.1 Initial Performance Testing

* * * * *

2.1.4 Emergency Fuel

The designated representative of a unit that has a federally-enforceable permit restricting the combustion of a particular fuel to emergencies where the primary fuel is not available is exempted from the requirements of this appendix for testing the NO_X emission rate during combustion of the emergency fuel. The designated representative shall include in the monitoring plan for the unit documentation that the permit restricts use of the fuel to emergencies only. When emergency fuel is combusted, report the maximum potential NO_X emission rate for the unit, in accordance with section 2.5.2.3 of this appendix. The designated representative shall also provide notice under § 75.61(a)(6) for each period when the emergency fuel is combusted.

* * * * *

2.2 Periodic NO_X Emission Rate Testing

Retest the NO_X emission rate of the gas-fired peaking unit or the oil-fired peaking unit while combusting each type of fuel (or fuel mixture) for which a NO_X emission rate versus heat input rate correlation curve was derived, at least once every 20 calendar quarters. If a required retest is not completed by the end of the 20th calendar quarter following the quarter of the last test, use the missing data substitution procedures in section 2.5 of this appendix, beginning with the first unit operating hour after the end of the 20th calendar quarter. Continue using the missing data procedures until the required retest has been passed. Note that missing data substitution is fuel-specific (i.e., the use of substitute data is required only when combusting a fuel (or fuel mixture) for which the retesting deadline has not been met). Each time that a new fuel-specific correlation curve is derived from retesting, the new curve shall be used to report NO_X emission rate, beginning with the first operating hour in which the fuel is combusted, following the completion of the retest.

2.3 Other Quality Assurance/Quality Control-Related NO_X Emission Rate Testing

* * * * *

2.3.1 For a stationary gas turbine, select at least four operating parameters indicative of the turbine's NO_X formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the turbine manufacturer's recommendations. * * *

2.3.2 For a diesel or dual-fuel reciprocating engine, select at least four operating parameters indicative of the engine's NO_X formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the engine manufacturer's recommendations. * * *

* * * * *

2.4 Procedures for Determining Hourly NO_X Emission Rate

* * * * *

2.4.2 * * * Linearly interpolate to 0.1 mmBtu/hr heat input rate and 0.001 lb/mmBtu NO_X. * * *

* * * * *

2.5 Missing Data Procedures

* * * For the purpose of providing substitute data, calculate the maximum potential NO_X emission rate (as defined in § 72.2 of this chapter) for each type of fuel combusted in the unit.

* * * * *

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 paragraphs 2.5.2.1, 2.5.2.2, and 2.5.2.3 of this section.

2.5.2.1 If the measured heat input rate during any unit operating hour is higher than the highest heat input rate from the baseline correlation tests, the NO_X emission rate for the hour is considered to be missing. Provide substitute data for each such hour, as follows.

2.5.2.1.1 Substitute the higher of: the NO_X emission rate obtained by linear extrapolation of the correlation curve, or the maximum potential NO_X emission rate (MER) (as defined in § 72.2 of this chapter), specific to the type of fuel being combusted. (For fuel mixtures, substitute the highest NO_X MER value for any fuel in the mixture.) For units with NO_X emission controls, the option to report the extrapolated NO_X emission rate may only be used if the controls are documented (e.g., by parametric data) to be operating properly during the missing data period (see section 2.5.2.2 of this appendix); or 2.5.2.1.2 Substitute 1.25 times the highest NO_X emission rate from the baseline correlation tests for the fuel (or fuel mixture) being combusted in the unit, not to exceed the MER for that fuel (or mixture). For units with NO_X emission controls, the option to report 1.25 times the highest emission rate from the correlation curve may only be used if the controls are documented (e.g., by parametric data) to be operating properly during the missing data period (see section 2.5.2.2 of this appendix).

2.5.2.2 For a unit with add-on NO_X emission controls (e.g., steam or water injection, selective catalytic reduction), if, for any unit operating hour, the emission controls are either not in operation or if appropriate parametric data are unavailable to ensure proper operation of the controls, the NO_X emission rate for the hour is considered to be missing. Substitute the fuel-specific MER (as defined in § 72.2 of this chapter) for each such hour.

2.5.2.3 When emergency fuel (as defined in § 72.2) is combusted in the unit, report the fuel-specific NO_X MER for each hour that the fuel is combusted.

* * * * *

61. Section 2 of Appendix F to Part 75 is amended by revising Equation F–3 in section 2.3 to read as follows:

Appendix F to Part 75—Conversion Procedures

* * * * *

2. Procedures for SO_2 Emissions

* * * * *

2.3 * * *

$$E_q = \frac{\sum_{h=1}^{n} E_h t_h}{2000} \qquad \text{(Eq. F-3)}$$

where: * * *

* * * * *

Appendix F Section 3 [Amended]

62. Section 3 of Appendix F to Part 75 is amended by removing the third sentence from section 3.3.5.

63. Section 5 of Appendix F to Part 75 is amended by:

a. In the definition of the variable ‘‘Q_g’’ of Equation F–20 in section 5.5.2 by revising the words ‘‘hundred cubic feet’’ to read ‘‘hundred standard cubic feet per hour’’;

b. In the first sentence of sections 5.6.1, 5.6.2, and 5.7 by revising the word ‘‘should’’ to read ‘‘shall.’’

c. In the definitions for the variables ‘‘t_i,’’ and ‘‘t_{cs},’’ and ‘‘n’’ of Equations F–21a and F–21b in sections 5.6.1 and 5.6.2 by revising the words ‘‘Operating time at a particular unit’’ in the definition of ‘‘variable t_i’’ to read ‘‘Unit operating time’’, by revising the words ‘‘Operating time at common stack’’ in the definition of ‘‘variable t_{cs}’’ with ‘‘Common stack or common pipe operating time’’, and by adding the words ‘‘or pipe’’ to the end of the definition of variable ‘‘n’’.

d. Revising the definitions of variables ‘‘HI_s’’, ‘‘t_{unit}’’, and ‘‘t_s’’, and adding a new definition for ‘‘s’’ in the definition of variables of Equation F–21c in section 5.7; and

e. Adding section 5.6.3.

The revisions and additions read as follows:

5. Procedures for Heat Input

* * * * *

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

* * * * *

5.6.3 As an alternative to using Equation F–21a or F–21b, the owner or operator may apportion the heat input rate at a common pipe to the individual units served by the common pipe based on the fuel flow rate to the individual units, as measured by uncertified fuel flowmeters. This option may only be used if a fuel flowmeter system that meets the requirements of appendix D to this part is installed on the common pipe. If this option is used, determine the unit heat input rates using the following equation:

$$HI_i = HI_{CP}\left(\frac{t_{CP}}{t_i}\right)\left[\frac{FF_i t_i}{\sum_{i=1}^{n} FF_i t_i}\right] \qquad \text{(Eq. F} - \text{21d)}$$

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CP} = Heat input rate at the common pipe, mmBtu/hr.

FF_i = Fuel flow rate to a unit, gal/min, 100 scfh, or other appropriate units

t_i = Unit operating time, hour 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).

t_{CP} = Common pipe operating time, hour 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).

n = Total number of units using the common pipe.

i = Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

* * * * *

HI_s = Heat input rate for the individual stack, duct, or pipe, mmBtu/hr.

t_{Unit} = Unit operating time, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s = Operating time for the individual stack or pipe, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

s = Designation for a particular stack, duct, or pipe.

Appendix F to Part 75 [Amended]

64. Section 7 of Appendix F to Part 75 is amended by revising the definitions of variables ‘‘E_h’’ and ‘‘HI’’ of Equation F–23 in section 7 to read as follows:

7. Procedures for SO_2 Mass Emissions at Units with SO_2 Continuous Emission Monitoring Systems During the Combustion of Pipeline Natural Gas or Natural Gas

* * * * *

E_h = Hourly SO_2 mass emission rate, lb/hr.

HI = Hourly heat input rate, as determined using the procedures of section 5.2 of this appendix, mmBtu/hr.

Appendix F to Part 75 [Amended]

65. Section 8 of Appendix F to Part 75 is amended by:

a. In the first sentence of section 8.1.1 by adding the word ‘‘rate’’ after each occurrence of the words ‘‘heat input’’;

b. Revising the definition of the variable ‘‘t_{cs}’’ of Equation F–25 in section 8.1.2; and

c. Adding definitions of the variables ‘‘p’’ and ‘‘u’’ to Equation F–25 of section 8.1.2.

The revisions and additions read as follows:

8. Procedures for NO_X Mass Emissions

* * * * *

8.1 * * *

8.1.2 * * *

t_{CS} = Common stack 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). (For each hour, t_{cs} is the total time during which one or more of the units which exhaust through the common stack operate.)

* * * * *

p = Number of units that exhaust through the common stack.

u = Designation of a particular unit.

* * * * *

66. Section 2 of Appendix G to Part 75 is amended by:

a. Amending section 2.1 to designate the first two sentences following the variables in Equation G–1 as section 2.1.1, the third sentence as section 2.1.2, and the remaining text as section 2.1.3;

b. Revising the first sentence of section 2.3; and

c. Revising the definition of variable ‘‘F_c’’ of Equation G–4 in section 2.3.

The revisions read as follows:

Appendix G to Part 75—Determination of CO_2 Emissions

* * * * *

2. Procedures for Estimating CO_2 Emissions from Combustion

* * * * *

2.3 In lieu of using the procedures, methods, and equations in section 2.1 of this appendix, the owner or operator of an affected gas-fired (or oil-fired) unit (as defined under § 72.2 of this chapter) may use the following equation and records of hourly heat input to estimate hourly CO_2 mass emissions (in tons). * * *

(Eq. G–4) * * *

F_C = Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1,420 scf/mmBtu for crude, residual, or distillate oil; and calculated according to the procedures in section 3.3.5 of appendix F to this part for other gaseous fuels.

* * * * *

Appendix G to Part 75 [Amended]

67. Section 5 of Appendix G to Part 75 is amended by:

a. Removing and reserving sections 5.1 and 5.1.1;

b. Revising the section heading and introductory text of section 5.2; and

c. Revising Table G–1 in section 5.2.2.

The revisions read as follows:

5. Missing Data Substitution Procedures for Fuel Analytical Data

* * * * *

5.2 Missing Carbon Content Data

Use the procedures of this section to substitute for missing carbon content data.

* * * * *

TABLE G–1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Missing data value
Oil and coal carbon content	Most recent, previous carbon content value available for that type of coal, grade of oil, or default value, in this table.
Gas carbon content	Most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this table.
Default coal carbon content	Anthracite: 90.0 percent. Bituminous: 85.0 percent. Sub-bituminous/Lignite: 75.0 percent.
Default oil carbon content	90.0 percent.
Default gas carbon content	Natural gas: 75.0 percent. Other gaseous fuels: 90.0 percent.

* * * * *

PART 78—APPEAL PROCEDURES FOR ACID RAIN PROGRAM

68. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

69. Section 78.1 is amended by removing from paragraph (a)(1) the words ‘‘parts 72, 73, 74, 75, 76, and 77 of this chapter’’ and adding in their place ‘‘parts 72, 73, 74, 75, 76, or 77 of this chapter or part 97 of this chapter’’; and adding a new paragraph (b)(6) to read as follows:

§ 78.1 Purpose and scope.

(b) * * *

(6) Under part 97 of this chapter,

(i) The adjustment of the information in a compliance certification or other submission and the deduction or transfer of NO_X allowances based on the information, as adjusted, under § 97.31;

(ii) The decision on the allocation of NO_X allowances to a NO_X Budget unit under § 97.41(b), (c), (d), or (e);

(iii) The decision on the allocation of NO_X allowances to a NO_X Budget unit from the compliance supplement pool under § 97.43;

(iv) The decision on the deduction of NO_X allowances under § 97.54;

(v) The decision on the transfer of NO_X allowances under § 97.61;

(vi) The decision on a petition for approval of an alternative monitoring system;

(vii) The approval or disapproval of a monitoring system certification or recertification under § 97.71;

(viii) The finalization of control period emissions data, including retroactive adjustment based on audit;

(ix) The approval or disapproval of a petition under § 97.75;

(x) The determination of the sufficiency of the monitoring plan for a NO_X Budget opt-in unit;

(xi) The decision on a request for withdrawal of a NO_X Budget opt-in unit from the NO_X Budget Trading Program under § 97.86;

(xii) The decision on the deduction of NO_X allowances under § 97.87; and

(xiii) The decision on the allocation of NO_X allowances to a NO_X Budget opt-in unit under § 97.88.

* * * * *

§ 78.2 [Amended].

70. Section 78.2 is amended by removing the words ‘‘shall apply to this part’’ and adding to their place ‘‘shall apply to appeals of any final decision of the Administrator under parts 72, 73, 74, 75, 76, 77, or 78 of this chapter’’.

71. Section 78.3 is amended by:

a. Amending paragraph (b)(3)(i) by adding, after the word ‘‘petitioner)’’, the words ‘‘or the NO_X authorized account representative under paragraph (a)(3) of this section (unless the NO_X authorized account representative is the petitioner)’’;

b. In paragraph (c)(7) by adding, after the words ‘‘title IV of the Act’’, the words ‘‘or part 97 of this chapter, as appropriate’’;

c. In paragraph (d)(2) by adding, after the words ‘‘Acid Rain Program’’ the words ‘‘or on an account certificate of representation submitted by a NO_X authorized account representative or an application for a general account submitted by a NO_X authorized account representative under the NO_X Budget Trading Program’’;

d. Redesignating paragraphs (d)(2) and (d)(3) as paragraphs (d)(3) and (d)(4) respectively; and

e. Adding new paragraphs (a)(3) and (d)(2).

The additions and revisions read as follows:

§ 78.3 Petition for administrative review and request for evidentiary hearing.

(a) * * *

(3) The following persons may petition for administrative review of a decision of the Administrator that is made under part 97 of this chapter and that is appealable under § 78.1(a) of this part:

(i) The NO_X authorized account representative for the unit or any NO_X Allowance Tracking System account covered by the decision; or

(ii) Any interested person.

* * * * *

(d) * * *

(2) Any provision or requirement of part 97 of this chapter, including the standard requirements under § 97.6 of this chapter and any emission monitoring or reporting requirements under part 97 of this chapter.

* * * * *

72. Section 78.4 is amended by adding two new sentences after the third sentence in paragraph (a) to read as follows:

§ 78.4 Filings.

(a) * * * Any filings on behalf of owners and operators of a NO_X Budget unit or source shall be signed by the NO_X authorized account representative. Any filings on behalf of persons with an interest in NO_X allowances in a general account shall be signed by the NO_X authorized account representative. * * *

* * * * *

§ 78.12 [Amended]

73. Section 78.12 is amended by adding, after the words ‘‘was properly issued or should be issued’’ in paragraph (a)(2), the words ‘‘or that a

NO_X Budget permit or other federally enforceable permit was properly issued or should be issued''.

PART 97—FEDERAL NO_X BUDGET TRADING PROGRAM

74. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7426, and 7601.

75. Section 97.2 is amended by:

a. Revising the definition of ''continuous emission monitoring system or CEMS'';

b. In the definition of ''Most stringent State or Federal NO_X emissions limitation'' by removing the words '', with regard to a NO_X Budget opt-in unit,'';

c. In the third sentence of the definition of ''NO_X allowance'' by adding the reference ''§ 97.40,'' after the word ''except'';

d. In the definition of ''NO_X Budget unit'' by removing the words ''Trading Program'';

e. In the definition of ''owner'' by adding the word ''the'' before the final occurrence of the word ''NO_X'' in paragraph (4) of the definition; and

f. In the definition of ''Percent monitor data availability'' by revising the words ''3,672 hours per'' to read ''the total number of unit operating hours in the'', and by revising the symbol ''%'' to read ''percent''.

The revisions and additions read as follows:

§ 97.2 Definitions.

* * * * *

Continuous emission monitoring system or *CEMS* means the equipment required under subpart H of this part to sample, analyze, measure, and provide, by means of readings taken at least once every 15 minutes (using an automated data acquisition and handling system (DAHS), a permanent record of nitrogen oxides (NO_X) emissions, stack gas volumetric flow rate or stack gas moisture content (as applicable), in a manner consistent with part 75 of this chapter. The following are the principal types of continuous emission monitoring systems required under subpart H of this part:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS. A flow monitoring system provides a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated DAHS. A NO_X concentration monitoring system provides a permanent, continuous record of NO_X emissions in units of parts per million (ppm);

(3) A nitrogen oxides emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated DAHS. A NO_X concentration monitoring system provides a permanent, continuous record of: NO_X concentration in units of parts per million (ppm), diluent gas concentration in units of percent O_2 or CO_2 (% O_2 or CO_2), and NO_X emission rate in units of pounds per million British thermal units (lb/mmBtu); and

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter. A moisture monitoring system provides a permanent, continuous record of the stack gas moisture content, in units of percent H_2O (% H_2O).

* * * * *

§ 97.4 [Amended]

76. Section 97.4(b) is amended by:

a. Amending the first sentence of paragraph (b)(1) by adding, after the words ''federally enforceable permit that'', the words ''restricts the unit to combusting only natural gas or fuel oil (as defined in § 75.2 of this chapter) during a control period and'';

b. In paragraph (b)(4)(i) by adding, after the words ''with the restriction on'', the words ''fuel use and''; and

c. In paragraph (b)(4)(vi)(B) by adding, after the words ''the restriction on'', the words ''fuel use or''.

77. Section 97.5 is amended by:

a. In the third sentence of paragraph (b)(2) by adding, after the word ''submit'', the words ''such a statement or'';

b. In paragraph (c)(6)(ii) by removing the period and replacing it with ''; or''; and

c. Adding a new paragraph (c)(6)(iii).

The revisions and additions read as follows:

§ 97.5 Retired unit exemption.

* * * * *

(c) * * *

(6) * * *

(iii) The date on which the unit resumes operation, if the unit is not required to submit a NO_X permit application.

* * * * *

§ 97.40 [Amended]

78. Section 97.40 is amended by removing the word ''program''.

§ 97.43 [Amended]

79. Section 97.43 is amended by removing paragraph (c)(8).

§ 97.51 [Amended]

80. Section 97.51 is amended by amending paragraph (b)(1)(i)(D) by adding, after the words ''with respect to'', the word '' NO_X''.

81. Section 97.54 is amended in paragraph (f) introductory text by revising the colon after the words ''as follows'' with a period and by adding a new sentence to the end of the paragraph to read as follows:

§ 97.54 Compliance.

* * * * *

(f) * * * For each State NO_X Budget Trading Program that is established, and approved and administered by the Administrator pursuant to § 51.121 of this chapter, the terms ''compliance account'' or ''compliance accounts'', ''overdraft account'' or ''overdraft accounts'', ''general account'' or ''general accounts'', ''States'', and ''trading program budgets under § 97.40'' in paragraphs (f)(1) through (f)(3) of this section shall be read to include respectively: a compliance account or compliance accounts established under such State NO_X Budget Trading Program; an overdraft account or overdraft accounts established under such State NO_X Budget Trading Program; a general account or general accounts established under such State NO_X Budget Trading Program; the State or portion of a State covered by such State NO_X Budget Trading Program; and the trading program budget of the State or portion of a State covered by such State NO_X Budget Trading Program.

* * * * *

§ 97.61 [Amended]

82. Section 97.61 is amended in paragraph (b) by revising the words ''same year as'' to read ''third year after the year of''.

83. Section 97.70 is amended by:

a. In paragraph (a)(1) by revising the words ''§§ 75.72 and §§ 75.76'' to read ''§§ 75.71 and 75.72'';

b. Revising paragraph (b)(3);

c. Revising paragraph (b)(4);

d. Removing paragraphs (b)(5) and (b)(6);

e. Redesignating paragraphs (b)(7), (b)(8) and (b)(9) as paragraphs (b)(5), (b)(6), and (b)(7), respectively;

f. Revising newly redesignated paragraphs (b)(5) and (b)(6); and

g. Revising paragraph (c).

The revisions and additions read as follows:

§ 97.70 General requirements.

* * * * *

(b) * * *

(3) For the owner or operator of a NO_X Budget unit under § 97.4(a) that

commences operation on or after January 1, 2002 and that reports on an annual basis under § 97.74(d) by the following dates:

(i) The earlier of 90 unit operating days after the date on which the unit commences commercial operation or 180 calendar days after the date on which the unit commences commercial operation; or (ii) May 1, 2002, if the compliance date under paragraph (b)(3)(i) of this section is before May 1, 2002.

(4) For the owner or operator of a NO_X Budget unit under § 97.4(a) that commences operation on or after January 1, 2002 and that reports on a control period basis under § 97.74(d)(2)(ii), by the following dates:

(i) The earlier of 90 unit operating days or 180 calendar days after the date on which the unit commences commercial operation, provided that this compliance date is during a control period; or (ii) May 1 immediately following the compliance date under paragraph (b)(4)(i) of this section, if such compliance date is not during a control period.

(5) For the owner or operator of a NO_X Budget unit that has a new stack or flue for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section or under subpart I of this part and that reports on an annual basis under § 97.74(d), by the earlier of 90 unit operating days or 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue.

(6) For the owner or operator of a NO_X Budget unit that has a new stack or flue for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section or under subpart I of this part and that reports on a control period basis under § 97.74(d)(2)(ii), by the following dates:

(i) The earlier of 90 unit operating days or 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue, provided that this compliance date is during a control period; or

(ii) May 1 immediately following the compliance date under paragraph (b)(6)(i) of this section, if such compliance date is not during a control period.

* * * * *

(c) *Commencement of data reporting.* (1) The owner or operator of NO_X Budget units under paragraph (b)(1) or (b)(2) of this section shall determine, record and report NO_X mass emissions, heat input rate, and any other values required to determine NO_X mass emissions (e.g., NO_X emission rate and heat input rate, or NO_X concentration and stack flow rate) in accordance with § 75.70(g) of this chapter, beginning on the first hour of the applicable compliance deadline in paragraph (b)(1) or (b)(2) of this section.

(2) The owner or operator of a NO_X Budget unit under paragraph (b)(3) or (b)(4) of this section shall determine, record and report NO_X mass emissions, heat input rate, and any other values required to determine NO_X mass emissions (e.g., NO_X emission rate and heat input rate, or NO_X concentration and stack flow rate) and electric and thermal output in accordance with § 75.70(g) of this chapter, beginning on:

(i) The date and hour on which the unit commences operation, if the date and hour on which the unit commences operation is during a control period; or

(ii) The first hour on May 1 of the first control period after the date and hour on which the unit commences operation, if the date and hour on which the unit commences operation is not during a control period.

(3) Notwithstanding paragraphs (c)(2)(i) and (c)(2)(ii) of this section, the owner or operator may begin reporting NO_X mass emission data and heat input data before the date and hour under paragraph (c)(2)(i) or (c)(2)(ii) of this section if the unit reports on an annual basis and if the required monitoring systems are certified before the applicable date and hour under paragraph (c)(1) or (c)(2) of this section.

* * * * *

84. Section 97.71 is amended by:

a. Revising paragraph (a) introductory text;

b. In paragraphs (b)(1), (b)(2), and (b)(3)(ii) by adding the word ''emission'' before the words ''monitoring system'' in each occurrence in paragraph (b)(1), in both occurrences in the first sentence of paragraph (b)(2), and in the one occurrence in paragraph (b)(3)(ii); and by revising the word ''a'' to read ''an'' after the word ''installs'' in the second sentence of paragraph (b)(1);

c. In paragraphs (b)(3)(iii) and (b)(3)(iv)(C) by removing each occurrence of the words ''or component thereof''; and

d. Revising the second sentence of paragraph (c), adding two new sentences to the end of paragraph (c), and removing paragraphs (c)(i) through (iii).

The revisions and additions read as follows:

§ 97.71 Initial certification and recertification procedures.

(a) The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of part 75 of this chapter for NO_X-diluent CEMS, flow monitors, NO_X concentration CEMS, or excepted monitoring systems under appendix E of part 75 of this chapter for NO_X, under appendix D for heat input, or under § 75.19 for NO_X and heat input, except that:

* * * * *

(c) * * * The owner or operator of such a unit shall also meet the applicable certification and recertification procedures of paragraph (b) of this section, except that the excepted methodology shall be deemed provisionally certified for use under the NO_X Budget Trading Program as of the date on which the certification application is received by the Administrator. The methodology shall be considered to be certified either upon receipt of a written notice of approval from the Administrator or, if such notice is not provided, at the end of the Administrator's 120 day review period. However, a provisionally certified or certified low mass emissions excepted methodology shall not be used to report data under the NO_X Budget Trading Program prior to the applicable commencement date specified in § 75.19(a)(1)(ii) of this chapter.

* * * * *

85. Section 97.72 is amended by:

a. In paragraph (a) by adding the word ''emission'' before the words ''monitoring system'' and the words ''subpart H,'' before ''appendix D''; and

b. In paragraph (b) by adding the word ''emission'' before ''monitoring system'' in the first sentence, by removing each occurrence of the words ''or component'' in the paragraph, and by adding a new final sentence.

The revisions and additions read as follows:

§ 97.72 Out of control periods.

* * * * *

(b) * * * The owner or operator shall follow the initial certification or recertification procedures in § 97.71 for each disapproved system.

86. Section 97.74 is amended by revising paragraphs (a)(1), (d)(1), and (d)(2)(ii); to read as follows:

§ 97.74 Recordkeeping and reporting.

(a) * * *

(1) The NO_X authorized account representative shall comply with all recordkeeping and reporting requirements in this section, with the

recordkeeping and reporting requirements under § 75.73 of this chapter, and with the requirements of § 97.10(e)(1).

* * * * *

(d) * * *

(1) If a unit is subject to an Acid Rain emission limitation or if the owner or operator of the NO_X budget unit chooses to meet the annual reporting requirements of this subpart H, the NO_X authorized account representative shall submit a quarterly report, documenting the NO_X mass emissions from the unit, for each calendar quarter beginning with:

(i) For a unit for which the owner or operator intends to apply or applies for the early reduction credits under § 97.43, the calendar quarter that covers May 1, 2000 through June 30, 2000. NO_X mass emission data shall be recorded and reported from the first hour on May 1, 2000; or

(ii) For a unit that commences operation before January 1, 2002 and that is not subject to paragraph (d)(1)(i) of this section, the calendar quarter covering May 1, 2002 through June 30, 2002. NO_X mass emission data shall be recorded and reported from the first hour on May 1, 2002; or

(iii) For a unit that commences operation on or after January 1, 2002:

(A) The calendar quarter in which the unit commences operation, if unit operation commences during a control period. NO_X mass emission data shall be recorded and reported from the date and hour when the unit commences operation; or

(B) The calendar quarter which includes May 1 through June 30 of the first control period following the date on which the unit commences operation, if the unit does not commence operation during a control period. NO_X mass emission data shall be recorded and reported from the first hour on May 1 of that control period; or

(iv) A calendar quarter before the quarter specified in paragraph (d)(1)(i), (d)(1)(ii), or (d)(1)(iii)(B) of this section, if the owner or operator elects to begin reporting early under § 97.70(c)(3).

(2) * * *

(ii) Submit quarterly reports, documenting NO_X mass emissions from the unit, only for the period from May 1 through September 30 of each year and including the data described in § 75.74(c)(6) of this chapter. The NO_X authorized account representative shall submit such quarterly reports, beginning with:

(A) For a unit for which the owner or operator intends to apply or applies for early reduction credits under § 97.43, the calendar quarter covering May 1, 2000 through June 30, 2000. NO_X mass emission data shall be recorded and reported from first hour on May 1, 2000;

(B) For a unit that commences operation before January 1, 2002 and that is not subject to paragraph (d)(2)(ii)(A)of this section, the calendar quarter covering May 1 through June 30, 2002. NO_X mass emission data shall be recorded and reported from the first hour of May 1, 2002;

(C) For a unit that commences operation on or after January 1, 2002 and during a control period, the calendar quarter in which the unit commences operation. NO_X mass emission data shall be reported from the date and hour corresponding to when the unit commences operation; or (D) For a unit that commences operation on or after January 1, 2002 and not during a control period, the calendar quarter which includes May 1 through June 30 of the first control period after the unit commences operation. NO_X mass emission data shall be recorded and reported from the first hour on May 1 of the first control period after the unit commences operation.

* * * * *

§ 97.87 [Amended]

87. Section 97.87 is amended in second sentence of paragraph (b)(1)(iii)(A) by adding the word ‘‘be’’ after the words ‘‘shall not’’.

88. Subpart J consisting of § 97.90 is added to read as follows:

Subpart J—Appeal Procedures

§ 97.90 Appeal Procedures.

The appeal procedures for the NO_X Budget Trading Program are set forth in part 78 of this chapter.

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