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Revisions to the Definitions and the Continuous Emission Monitoring Provisions of the Acid Rain Program and the NO_X Budget Trading Program; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72 and 75

[FRL–7207–4]

RIN 2060–AJ43

Revisions to the Definitions and the Continuous Emission Monitoring Provisions of the Acid Rain Program and the NO_X Budget Trading Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this action, EPA is taking final action on the portions of the June 13, 2001 proposed rule revisions that modify the existing requirements for sources affected by the Acid Rain Program and by the NO_X Budget Trading Program under the October 27, 1998 NO_X SIP Call. Certain changes to the proposed rule revisions have been made based on the public comments received. EPA is not finalizing the proposed changes at this time to the Appeal Procedures or to the Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport. Today's final rule establishes additional flexibility and options for sources in meeting the continuous emission monitoring system (CEMS) requirements under programs to reduce sulfur dioxide and nitrogen oxides emissions. These revisions may apply to sources that monitor and report emissions only during the ozone season, as well as to sources that monitor and report emissions for the entire year. The provisions in this final rule benefit the environment by ensuring that sulfur dioxide ($S0_2$), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions are accurately monitored and reported, even as they benefit the affected industrial sources by creating opportunities to adopt cost saving procedures.

DATES: The effective date of this rule is July 12, 2002. However, regulated entities will have additional time to implement certain requirements, as described in Section V, Rule Implementation, and in the rule.

ADDRESSES: *Docket.* Supporting information, including public comments, used in developing the regulations is contained in Docket No. A–2000–33. This docket is available for public inspection and photocopying between 8:00 a.m. and 5:30 p.m. Monday through Friday, excluding government holidays, and is located at: EPA Air Docket (MC 6102), Room M–1500, Waterside Mall, 401 M Street, SW, Washington, DC 20460. A reasonable fee may be charged for photocopying.

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

SUPPLEMENTARY INFORMATION: A redline/strikeout version of 40 CFR parts 72 and 75 as amended by this final 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 electric generators, produce steam, or cogenerate electricity and steam. While part 75 of title 40 of the Code of Federal Regulations (40 CFR) primarily regulates the electric utility industry, certain State and Federal NO_X mass emissions programs also rely on 40 CFR part 75 (subpart H), 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, or organization is regulated by this action, you should carefully examine the applicability provisions in 40 CFR 72.6, 72.7, and 72.8 and 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 Final Rule

Today's action modifies existing monitoring and reporting requirements in 40 CFR parts 72 and 75. These requirements support emission control programs that use the monitoring and reporting provisions of part 75, such as the Acid Rain Program, and the NO_X Budget Trading Program developed under 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 changes finalized are as follows: the definitions of ''pipeline natural gas'' and ''natural gas'' in § 72.2 are finalized as proposed to remove all references to the H_2S content of the fuel and instead be based on total sulfur content, along with corresponding changes appendix D to part 75; the low mass emissions (LME) units provisions in § 75.19 are clarified and expanded and, for units with certain types of NO_X emission controls, qualification as a LME unit is made easier; the CEMS missing data procedures are revised to allow fuel-specific missing data substitution; the missing data procedures in subpart H of part 75 are expanded and clarified for sources that are non-load based and/or report emission data only in the ozone season; the NO_X span and range provisions in appendix A are revised to make them easier to implement for combustion turbines; and the alternate calibration error limit for daily operation is changed from 10 ppm to 5 ppm for units with span values of 50 ppm or less.

EPA has developed a Response to Comment document (see Docket No. A–2000–33, Item V–C–1) as a supplement to this preamble, which addresses all the comments received on the proposed rule revisions. Comments that were raised and are not addressed in this preamble are responded to in this supplemental document.

III. Statutory Authority, Regulatory History, and Stakeholder Involvement

In accordance with titles I and IV of the Clean Air Act (CAA, or the Act), with today's action EPA is promulgating revisions to rules implementing programs that the Agency has established to mitigate interstate transport of nitrogen oxides, as well as to reduce the acidic deposition precursor emissions of sulfur dioxide and nitrogen oxides. EPA originally promulgated 40 CFR parts 72 and 75 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 CEMS requirements in part 75 and relevant definitions in part 72 (*see* below).

Section 110 of the Act requires that State Implementation Plans (SIPs) prohibit sources from contributing significantly to nonattainment or maintenance of attainment in another State. On October 27, 1998, EPA issued the NO_X SIP Call, a final rule under section 110 requiring certain States to revise their SIPs to meet NO_X emission budgets to prevent such significant contribution to ozone nonattainment. States may adopt in their SIPs a NO_X Budget Trading Program for large electric generating units (EGUs) and large non-electric generating units (non-EGUs) and require such units to monitor under part 75. Further, section 126 of the Act authorizes EPA to directly regulate, and require reductions of NO_X emissions from, sources that emit in violation of the prohibition in section 110 against significantly contributing to ozone nonattainment or maintenance problems in a downwind State. On January 18, 2000, EPA published a finding that large EGUs and certain large non-EGUs in particular States named in petitions filed by several northeastern States emit NO_X in violation of Section 126 of the CAA (65 FR 2674). In that same notice, the EPA finalized the Federal NO_X Budget Trading Program in part 97 as the control remedy and required that these units monitor under part 75.

In today's rule, the provisions of parts 72 and 75 are revised to modify the requirements for sources under the Acid Rain Program, the NO_X SIP Call, and the Federal NO_X Budget Trading Program.

As noted above, the Agency first promulgated parts 72 and 75 under title IV on January 11, 1993. On May 17, 1995 and November 20, 1996, the Agency revised parts 72 and 75 to make implementation simpler (60 FR 26510 and 61 FR 59142). On May 21, 1998, the Agency proposed additional revisions to parts 72 and 75 to make implementation easier and more efficient, to improve quality assurance requirements, and to create new alternative monitoring options (63 FR 28032). EPA promulgated final rule revisions addressing some of these additional proposed revisions, based on comments received, when EPA promulgated the NO_X SIP Call (63 FR 57356). On May 26, 1999, EPA issued final rule revisions addressing the remaining May 21, 1998 proposed revisions (64 FR 28564). On June 13, 2001, EPA proposed further revisions to parts 72, 75, 78, and 97 (66 FR 31978). The revisions to parts 72 and 75 are being finalized in today's rule, while the changes to parts 78 and 97 will be addressed in a later rulemaking.

Throughout the implementation of the Acid Rain Program, particularly since 1995, EPA has worked and continues to work on a regular basis with stakeholders, the regulated community, the public, other state and local agencies, and environmental groups and consultants. Internally, EPA holds frequent policy meetings to discuss many of the questions and problems that affected sources raise to their Regional contact in EPA. Many of the changes in today's rule result from industry petitions to the Agency as well as comments, phone calls, and dialogues during conferences and workshops. Most recently, EPA conducted two conferences in July (Louisville, KY) and September (Alexandria, VA) of 2001, and then initiated five regional workshops targeted at the regulated community and state agencies to support the Acid Rain Program and assist in implementing the NO_X Budget Trading Program. EPA is committed to this ongoing interaction with stakeholders across all spectra.

IV. Summary of Major Comments and Responses

EPA responded to all comments received by the close of the extended comment period, August 20, 2001, regarding the current proposal. EPA's responses are summarized in this section of the preamble and are available in their entirety in the Response to Comment document in the rule docket (*see* Docket No. A–2000–33, Item V–C–1). The majority of comments related to parts 72 and 75; therefore, this section addresses those issues. Revisions to part 78 received no comments, and revisions to part 97 received only two comments, both of which are addressed in the Response to

Comment document. As noted above, EPA intends to finalize changes to part 78 and 97 in a separate rulemaking. The major topics in part 75 that EPA is focusing on in this section are: missing data; LME units; quality assurance and quality control (QA/QC); appendix D; other highlights and changes; and streamlining changes.

A. Missing Data

1. What Changes to the CEMS Missing Data Procedures of §§ 75.31 Through 75.37 Are Finalized?

Background

a. What is Currently Required?

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.

Existing 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 (*e.g.,* SO_2, NO_X, flow rate) in order to provide substitute data values when a historical lookback is required.

For units with add-on SO_2 or NO_X emission controls, § 75.34 allows two principal missing data options. The owner or operator may either: (1) Report maximum potential values or, if the controls are documented to be operating properly, report the standard missing data procedures; or (2) petition the Administrator to develop and use site-specific parametric monitoring procedures for missing data substitution in lieu of using the standard missing data procedures. Section 75.34(a)(2) also allows the owner or operator to petition the Administrator for permission to report the maximum controlled emission rate recorded in the previous 720 quality-assured monitor operating hours (without regard to control operational status), in cases where the standard missing data routines would require the maximum value in the lookback period to be reported.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed to revise the part 75 missing data procedures to allow the standard missing data substitution in § 75.33 to be done on a fuel-specific basis. The proposed revisions would allow the owner or operator to create and maintain separate databases for missing data purposes for each type of fuel combusted in the unit. Substitute data values would be derived from the appropriate database, depending on the type of fuel being burned during the missing data period.

For units with add-on SO_2 or NO_X emission controls, EPA further proposed to remove the petition provision from § 75.34(a)(2) and replace it with a new missing data option, based on the operating status of the emission controls. The owner or operator of a unit with add-on SO_2 or NO_X emission controls would be allowed to create and maintain two separate databases, controlled and uncontrolled, for missing data purposes. Any hour in which the add-on controls were documented to be operating (*i.e.,* on) would be included in the controlled database. Any hour in which the controls were not operating (*i.e.,* off) would be included in the uncontrolled database. The appropriate substitute data value for each hour of a missing data period would be taken from either the controlled or uncontrolled database, depending on whether the emission controls were documented (by means of parametric data) to be operating properly during the hour.

EPA also proposed to change 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. 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 a minimum of 720 hours of 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 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.

c. What Changes Is EPA Finalizing?

Today's rule finalizes the fuel-specific missing data option, with some editorial changes including new language addressing the co-firing of fuels (*see* Discussion, below). However, based on comments received, EPA is not adopting the other proposed missing data option, which would have allowed the owners or operators of units with add-on emission controls to separate their data into controlled and uncontrolled databases. The final rule replaces, in response to these comments, the proposed option with a provision that accomplishes a similar objective with respect to seasonally operated control devices, without requiring control device operational status to be documented. The replacement provision allows subpart H sources that report data on a year-round basis to separate their quality-assured NO_X emission data into ozone season data and non-ozone season data for missing data purposes. The final rule also retains the provision in § 75.34 which allows sources to petition to report the maximum controlled emission rate in a 720-hour lookback period.

Discussion

Two commenters were supportive of the proposed fuel-specific missing data option (Utility Air Regulatory Group (UARG); Clean Energy Group). However, another commenter asked EPA to explain what it means to create and maintain a ''separate database'' for each fuel or blend, and also asked how a ''blend'' is determined (KVB–Enertec (KVB)). Two commenters questioned how these proposed missing data procedures would be implemented for units that sometimes co-fire different types of fuel (UARG, KVB). Specifically, the commenters expressed concern about having to maintain an extra database for co-fired hours. One of the commenters suggested keeping only single-fuel databases and pro-rating the missing data values during co-fired hours (UARG).

Based on these comments, EPA incorporates the fuel-specific missing data option into today's rule, although the final rule language is somewhat modified from the proposal. The final rule differs from the proposal in that it provides for greater flexibility in how to implement the new missing data option. Paragraphs (b)(6) and (c)(8) in § 75.33 give more general implementation guidelines, rather than providing detailed instructions. Regarding the comments about co-firing, while EPA agrees that it is desirable to maintain as few databases as possible, the Agency did not incorporate the commenter's suggested approach because the commenter did not provide an adequate explanation of how it would work. However, today's rule provides an alternative to maintaining separate databases for co-fired hours for units that co-fire fuels and elect to use the fuel-specific missing data option. The final rule allows the owner or operator to keep single-fuel databases, provided that the database for the fuel with the higher emission rate is used to provide substitute data values during co-fired hours.

Regarding the Agency's proposal to provide a control status-specific missing data option for units with add-on SO_2 and NO_X emission controls, two commenters supported the concept of this option (UARG, Clean Energy Group). However, strenuous objections were raised to the proposed method of documenting proper operation of the add-on controls (UARG; Robert Machaver (Machaver)). In particular, the commenters objected to the potential high cost of developing complex correlations between parametric data and control device removal efficiency and questioned the usefulness and reliability of such correlations. One commenter also objected to removing the petition provision from § 75.34(a)(2), which would allow the source to report the maximum controlled value in a 720-hour lookback period (UARG).

After careful consideration of the comments, EPA replaces the proposed missing data option with a procedure that will achieve the objective of the proposal for seasonally operated controls, without being dependent on the operational status of the add-on emission controls. The Agency also is not adopting the requirement to develop a correlation between control device removal efficiency and parametric data to demonstrate proper operation of the add-on emission controls, principally in response to the objections of the commenters to the cost and level of effort needed to develop correlations between parametric data and control device removal efficiency. The original rule language in § 75.34(d) is retained, requiring sources to specify in the quality assurance (QA) plan for the unit the essential parameters and ranges needed to verify proper operation of the add-on emission controls.

It should be noted that one of the principal reasons EPA proposed the control status-specific missing data option in § 75.34(a)(2) for units with add-on emission controls was to accommodate units that are subject to the Federal NO_X Budget Trading Program (which is being implemented as a result of the NO_X SIP Call). In particular, many units required to report NO_X emissions data on a year-round basis will operate their add-on NO_X emission controls only during the ozone season, in order to comply with the NO_X emission reduction requirements of the NO_X SIP Call. The proposed missing data option would have allowed these sources to separate their uncontrolled and controlled emission data, thereby providing a more equitable scheme for missing data substitution.

After further consideration, taking into account the supportive comments for the concept of the proposed missing data option, EPA believes that the objective of the option can be accomplished in a different way, without requiring separate controlled and uncontrolled databases to be maintained or that any parametric correlations be developed. Accordingly, § 75.34(a)(2) of today's rule allows the owner or operator to separate the historical, quality-assured NO_X emissions data into ozone season and non-ozone season NO_X data, for missing data purposes. Use of this missing data option is limited to units that report NO_X mass emissions data on a year-round basis under subpart H of part 75, and that operate their NO_X emission controls only during the ozone season, or in a less efficient manner outside the ozone season. During periods of NO_X missing data, revised § 75.34(a)(2) specifies that the appropriate substitute data values are to be drawn from one database or the other, depending on whether the missing data period is inside or outside the ozone season. Missing data periods that begin outside the ozone season and continue into the ozone season are treated as two separate missing data incidents, one ending on April 30, hour 23, and one beginning on May 1, hour 00. Further, the standard NO_X missing data algorithms may be applied at all times during the non-ozone season missing data periods, without any requirement to record parametric data to verify proper operation of add-on controls.

2. How Are the CEMS Missing Data Provisions of Subpart H Affected by Today's Rule?

Background

a. What Is Currently Required?

The missing data procedures for units which are subject to a State or Federal NO_X mass emissions reduction program and must monitor NO_X mass emissions according to subpart H of part 75 are specified in §§ 75.70(f) and 75.74(c)(7). Section 75.70(f) requires the initial and standard missing data procedures of §§ 75.31 through 75.37 to be used for sources that report emission data on a year-round basis. Section 75.74(c)(7) requires subpart H sources that report data on an ozone season-only basis to use the missing data procedures of §§ 75.31 through 75.37 also, except that only data from within the ozone season are to be used in the historical lookbacks.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed to revise § 75.74(c)(7) by adding a new paragraph (iii), with subparagraphs (A) through (M), explaining how to apply the part 75 missing data procedures in §§ 75.31 through 75.37 on an ozone season-only basis. EPA proposed 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. Thus, 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 include all of the quality-assured CEMS data that have been recorded throughout the year. Also, the percent monitor data availability (PMA) calculations described in § 75.32, which are always based on a particular number of unit operating hours, include unit operating hours from all four calendar quarters of the year.

Proposed § 75.74(c)(7)(iii) 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. The missing data instructions for ozone season-only reporters were written in a parallel manner to the missing data procedures for year-round reporters.

c. What Changes Is EPA Finalizing?

Today's rule finalizes the changes to § 75.74(c)(7) as proposed, except that for both PMA calculations and historical missing data lookbacks, the lookback periods would be limited to three years (26,280 clock hours) prior to the missing data period, rather than three ozone seasons as proposed.

EPA further notes that the fuel-specific missing data option described above in question 1 of this section is available to all subpart H sources, and the option to create and maintain separate ozone season and non-ozone season databases for missing data purposes is available to subpart H sources that report emissions data on a year-round basis.

Discussion

EPA received only one comment on the proposed missing data revisions to § 75.74(c)(7). The commenter recommended that the lookback period be limited to three years prior to each missing data period rather than three ozone seasons as proposed (Environmental Systems Corporation (ESC)). Another commenter questioned similar language found in proposed

§ 75.33(c)(9), *i.e.*, the parenthetical expression ''(or three ozone seasons)'' next to the words, ''three years'', referring to missing data lookbacks (Monitor Labs (Monitor)). EPA agrees with the commenters that for the purposes of missing data lookbacks, consistency is essential. For both year-round reporters and sources that report emissions on an ozone season-only basis, no data recorded more than three years prior to the missing data period should be used in the historical lookbacks. Therefore, in today's rule, all references in § 75.33, § 75.74(c)(7)(iii), and elsewhere to data recorded in the previous three ozone seasons are removed and replaced with references to the previous three years.

3. What CEMS Missing Data Provisions Are Finalized for Units That Do Not Produce Electrical or Thermal Output?

Background

One of the main objectives of the June 13, 2001, proposed rule was to modify the existing monitoring and reporting sections of parts 72 and 75 that apply to NO_X emission reduction programs, such as the Federal NO_X Budget Trading Program 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 EGUs in their NO_X reduction plans. Some of these non-EGUs (such as cement kilns and refinery process heaters) do not produce electrical or thermal output, *i.e.*, ''load.''

a. What Is Currently Required?

EPA examined the part 75 missing data provisions to assess whether those provisions are adequate for determining NO_X mass emissions from non-EGUs. As a result of this assessment, EPA concluded that for industrial boilers which produce steam load and which are very similar to electric utility boilers, no significant changes to the missing data provisions of part 75 would be required. However, for cement kilns and refinery process heaters which do not produce electricity or steam load, EPA concluded that modifications to the missing data routines for NO_X concentration, NO_X emission rate, stack flow rate, and fuel flow rate would be necessary, since these missing data routines are load-dependent.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed non-load-based missing data routines which are modeled after, and are much the same as, the existing routines for load-based units, with one important difference: the owner or operator of a non-load-based unit would have a choice to define and use ''operational bins'' to segregate the quality-assured emissions data, or not to use operational bins at all.

The reason EPA proposed allowing the use of operational bins was 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 were proposed as new sections 3 and 4 of appendix C to part 75. These new provisions would require the owner or operator to provide a complete description of each operational bin in the hardcopy portion of the monitoring plan and to monitor the operating conditions used to define the operational bin.

c. What Changes Is EPA Finalizing?

Today's rule finalizes the missing data provisions for units that do not produce electrical or steam load. The final rule differs from the proposal in the following ways: (1) In Table 3, the algorithms requiring a comparison of the average value in a 2,160 lookback period against the 90th (or 95th) percentile value have been simplified to require that just the percentile value be reported (the reasons for this change are given in the Discussion immediately below); and (2) proposed section 4 of appendix C, which would have allowed the use of operational bins for fuel flow rate missing data, is not adopted (the reasons for not finalizing that option are explained in detail in the Discussion in Section IV. D.4. of this preamble).

Discussion

EPA received comments on the proposed missing data provisions for non-load-based units from only two commenters (KVB; American Portland Cement Alliance (APCA)). The first commenter stated that the rule should provide a clear way of defining ''operational bins'' (KVB). The second commenter fully supported the proposed operational bin provisions, but objected to the use of 90th percentile, 95th percentile, and maximum values in the missing data lookback periods for NO_X and flow rate, claiming that these percentile values, which may be reasonable for EGUs, are unfairly punitive for the affected units in the commenter's industry (APCA). The second commenter included supplementary data previously presented to EPA in 1999 (see Docket No. A–2000–33, Item II–C–2) and proposed an alternate missing data protocol, using a ''percent-above-average'' approach in lieu of using the 90th percentile, 95th percentile, and maximum values. The commenter asked EPA to revisit the Agency's prior data analysis, claiming that EPA's previous analysis had overstated the variability of EGU emission data by not taking certain factors into consideration. EPA declines to adopt the commenter's percent-above-average proposal, and concludes that no additional data analysis is necessary in order to support an appropriate missing data routine for non-load units.

The most significant reason that EPA rejects the commenter's proposal is because the proposal rests on a fundamental misunderstanding of the basis and purpose of the missing data procedures. As stated in previous meetings and conversations with the commenter and in EPA's detailed written response, sent to the commenter on November 22, 2000 (see Docket No. A–2000–33, Item II–C–3), the key issue is the following: the missing data procedure in 40 CFR part 75 is designed to provide substitute values strictly relative to a unit's own emissions history, not compared to the emissions history of the universe of all units, as would be the case using the proposed percent-above-average multiplier.

The missing data procedure strictly pertains to the monitoring of emissions, not to the operation of a unit. It implements Section 412(d) of the CAA which mandates EPA's Administrator to prescribe a means to calculate emission values during periods when data from the certified monitor is unavailable. The purpose is to substitute a value that is not lower than the unknown actual value for an improperly operated monitor. This means that a comparison of the variability of one unit's emission data to another unit's emission data (or to a class of other units' emission data), or a comparison of emission levels at one unit relative to another unit (or class of units), is not relevant in assessing the applicability of the missing data procedure. This can be seen both in the regulatory history and the structure of the missing data procedure.

As stated in the preamble to the original 40 CFR part 75 regulations published in the **Federal Register** on January 11, 1993 (58 FR 3635), the primary intent in developing the missing data procedure was to provide a ''substantial incentive to improve monitor availability'' (58 FR 3637). To provide this substantial incentive, the Agency originally considered proposals to use only the maximum previous value recorded and the average of the five highest previously recorded values, and finally settled on the current tiered approach. All of the approaches, contemplated and adopted, were premised on providing an incentive to keep monitors operational by requiring substitution of either the maximum value previously recorded at each specific facility or a value higher than at least 90 percent (for shorter monitor outages) or 95 percent (for longer monitor outages) of the values previously recorded at the specific unit. None of the approaches offered variations based on differences in emission variability or emission levels encountered at different units. To do so would have been contrary to the goal of providing, for each and every unit, a ''substantial incentive to improve monitor availability'' (58 FR 3637, January 11, 1993).

The commenter, on the other hand, proposes using a multiplier which is based on the averaged emissions history of a different set of units, that of utility units, which in aggregate would not display the high emissions excursions that are typical of cement kilns. The commenter does not dispute the need for a missing data procedure as an important component of a monitoring program; just its application during times of long monitor outage and low monitor availability—exactly the times that the missing data routine was designed to limit. Their proposal suggests using the ''percent above the average for each percentile as calculated from the electric utility boiler data to the cement kiln data.'' This proposal underscores the commenter's misunderstanding about the purpose of missing data.

Use of the commenter's proposed percentage-above-average multiplier would mean that even in situations of substantial monitor outages (representing as much as 20 percent of a monitoring year), kilns whose own emission history displayed frequent excursions into high emission levels (as illustrated, for example, in commenter's Figure 1, page 2 of the attachment to Docket No. A–2000–33, Item IV–D–2) would substitute values substantially below these high excursions. The proposed procedure could have an effect completely contrary to the regulatory intent of the missing data procedure, *i.e.*, providing an incentive to improve monitor availability. In fact, EPA believes this approach, were it to be employed, would cause a reverse incentive to turn off monitors at affected facilities. The commenter acknowledges that the NO_X emitted from their facilities is thermal NO_X, which is a critical aspect of the product's quality control. Because temperatures are product-related, they are carefully monitored. Operators may be able to predict, therefore, when emissions are high. Because of the market value of emissions, the percent-above-average multiplier approach may encourage sources to turn off monitors at higher fuel flow rates or higher kiln temperatures when NO_X emissions might increase. EPA experienced similar concerns with the utility industry in the early 1990s, when a diverse array of commenters recommended that EPA provide sufficiently punitive procedures to ensure that there would be an ''effective deterrent to deliberate shutdowns of CEMS during period of high emissions' (58 FR 3637, January 11, 1993). These concerns were a factor in the final approach that was adopted.

The commenter's methodology is inconsistent with the purpose of missing data. The commenter misconstrues the concept of missing data substitution and its implementation by stating that missing data routines were created to encourage three activities: maintaining CEMS; getting malfunctioning CEMS back on line quickly; and operating power plants efficiently so as to avoid NO_X spikes. While the first two points are correct, the third ''activity'' has never been a purpose of missing data. Rather, it is a consequence of efficient plant operations which has some ancillary benefits. Operating bins, discussed later, afford similar benefits to kiln operators. In fact, there are numerous options available to kiln operators, as there are for EGUs, to minimize the need for and impacts of missing data routines. For instance, in the early years of monitoring, some utilities that were initially concerned about missing data protocols installed redundant backup systems so that if one monitor went down, another was available and no missing data period would be incurred. Others bought ''like-kind replacement analyzers'' that were also available should the primary monitor not perform. However, over time, many of these sources have found that these options were not necessary because, through proper maintenance of the CEMS, performance is usually not an issue. The commenter's analysis does not consider these options.

The commenter also claims that ''facilities with less reliable CEMS'' need tailored missing data protocols ''to represent the realities of cement manufacturing.'' EPA does not believe that this comment presents a relevant issue. The commenter has provided no evidence to demonstrate any basis for monitors to perform less reliably on cement kilns. The NO_X concentration monitor and stack flow monitor (critical CEMS components) that are installed on a cement kiln stack are no different from those that might be installed at a coal-fired utility boiler. APCA indicates that most of its companies burn coal as fuel in their cement making process. The result of burning coal, just like in a utility boiler, is a gas that exits the kiln through a stack. The CEMS samples that gas on minute-by-minute intervals in order to come up with a quality assured operating hour of data, which is banked in a data acquisition and handling system (DAHS). The only time the owner or operator of a cement kiln will have to use the missing data substitution protocol is when the CEMS is out of order or not operating properly. Utilities are currently maintaining CEMS at above 99 percent availability, up from around 95 percent when CEMS were first installed on utility boilers under the Acid Rain Program in the mid 1990s.

The commenter has also suggested that the standard missing data procedure creates an equity issue, and that EPA is penalizing the cement industry unfairly because of its high variability. EPA disagrees with the commenter. EPA requires that all continuous emission monitors be continuously maintained and operated and has created an incentive structure, in the form of missing data procedures, to ensure this. Studies have demonstrated variability, comparable to that which APCA claims for cement kilns, for utility units in the pre- and post-control mode (see Docket No. A–92–15, Item II–I–26). EPA has demonstrated in previous data analyses and correspondence with the commenter (see Docket No. A–2000–33, Items II–C–2 and II–C–3) that there are many EGUs with variability of NO_X emission rate comparable to that for the cement kilns. EPA examined data from more than 1,000 utility boilers and compared it to the limited data submitted by the commenter for seven cement kilns out of the approximately 200 kilns operating in the U.S.. EPA's intent in performing the data analysis was to show that, even taken at face value, the commenter's contention is without merit: a statistical analysis of the data showed that there are EGUs with just as much emission rate variability (reflected as relative standard deviation). Consequently, EPA does not accept the premise of the commenter's concern.

Further, it is important to note that many utilities have done an exceptional job, over time, of reducing emission variability. EPA would also note that the cement industry data analysis did not reflect data stratification into operational bins. At the commenter's suggestion, EPA has proposed the use of ''operational bins'' which allow emissions data to be sub-categorized for missing data purposes (*e.g.*, for mid-kiln injection of fuel, a bin for injection system on and a bin for injection system off). These operational bins are analogous to the load bins available to EGUs, and will allow non-load units to avoid unnecessarily reporting the highest missing data value, if they can show that during the time CEMS are not operational the unit was in an operating bin for which a ''lower'' highest missing data value applies. The Agency is confident that application of the operating bin concept will reduce the conservatism of missing data procedures for kilns.

The commenter also suggests that EPA's proposal to remove the hour before/hour after (HB/HA) algorithm from the missing data routine for non-load based units suggests that the Agency concedes that kilns are more variable than EGUs. To the contrary, the purpose of the HB/HA option, as applied to load based units, is to capture the fact that units may be operated for extended periods at peak load. In such a case, a unit at its maximum load and maximum emissions may actually have greater than the 95th percentile emissions (*i.e.*, the 95th percentile may be too low a number under such conditions to substitute for the unknown value). So the HB/HA provision was developed to potentially capture such incidents by providing, during periods of long outages, a substitute value which is the greater of the HB/HA or the 90th (or 95th) percentile in a 2,160 hour lookback period. Based on commenter-provided data for seven cement kilns, EPA initially suspected that short-term variability could cause the application of HB/HA to be punitive. However, although the Agency has concerns relating to the representation of industry data, we believe that there is little risk in deferring applicability of the provision until such time as sufficient information is available on an operating bin basis to assess the effectiveness of percentile based data substitution. EPA reserves the right to examine cement kiln data that is reported in the future and reconsider whether or not this decision is appropriate.

As an alternative, in the June 13, 2001 proposed rule revisions, EPA proposed to replace the HB/HA criterion with the average value in a 2,160-hour lookback period in the NO_X missing data algorithms in Table 3. The commenter has correctly pointed out in comments on the proposal that EPA's proposed replacement for the HB/HA criterion in Table 3 (*i.e.*, comparison of the average in the 2,160 hour lookback period and 90th or 95th percentile value of the same set of data) is technically unsound. The proposed replacement algorithms that require the ''higher of'' the 90th (or 95th) percentile value or the average value to be reported are meaningless, since the 90th or 95th percentile values will always be higher than the average for the same data set. Therefore, in the interest of regulatory clarification, Table 3 has been modified to eliminate the required comparison of averages and higher percentiles, simply leaving in place the percentile requirement.

In view of the these considerations, in today's rule EPA finalizes the missing data provisions as proposed for both load-based and non-load-based units, save for the revision to Table 3 that removes the requirement for the average versus percentile value comparisons.

4. Will Today's Rule Affect the Way in Which Load Ranges (or ''Bins'') Are Established for Missing Data Purposes?

Background

a. What Is Currently Required?

Section 2 of appendix C to part 75 provides a procedure for establishing missing data load ranges (''bins'') for NO_X emission rate, NO_X concentration, stack flow rate and fuel flow rate. The procedure consists of establishing 10 (or, in some cases, 20) load ranges, which are defined as percentages of the maximum hourly gross load of the unit.

b. What Changes Were Proposed?

EPA proposed to revise section 2.2.1 of appendix C, particularly 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. Having established the maximum hourly gross load, the missing data load ranges would then be determined as percentages of the MHGL.

c. What Changes Is EPA Finalizing?

EPA is not adopting these proposed changes, based on the comments received. Today's final rule retains the existing text of section 2.2.1 of appendix C.

Discussion

EPA received significant adverse comments on the proposed changes to section 2.2.1 of appendix C. Two commenters objected to the proposed removal of the option to use hourly gross steam load to establish the load bins (UARG, Machaver). The commenters also raised technical questions and issues. Concerns were expressed that the proposed method of converting heat input to equivalent electrical output would underestimate the electrical output of the steam turbine for combined cycle units, and that the method does not provide a means of accounting for hourly load contributions from the duct burner during fuel flowrate missing data periods (UARG, Machaver). After consideration of these comments, EPA is not finalizing the proposed changes to section 2.2.1 and retains the existing rule text.

B. Low Mass Emissions Units

1. Does Today's Rule Change the Qualification Requirements for Low Mass Emissions Units?

Background

a. What Is Currently Required?

In October, 1998, EPA promulgated the low mass emissions (LME) methodology in § 75.19, which provides certain qualifying units an alternative means of complying with part 75 without installing continuous monitoring systems. For an Acid Rain Program unit to qualify to use the LME methodology, § 75.19(a) states that the unit must be oil- or gas-fired, combusting only natural gas or fuel oil, and must demonstrate that its emissions do not exceed 25 tons of SO_2 and 50 tons of NO_X per year. This demonstration must consider both actual (or projected) emissions and emissions calculated as set forth in § 75.19. For a non-Acid Rain unit subject to a State or Federal NO_X emissions reduction program that adopts the monitoring provisions of subpart H of part 75, if the unit reports NO_X mass emission data only during the ozone season, § 75.74(c)(10) states that the unit can qualify for LME status if it demonstrates that its emissions do not exceed 25 tons of NO_X per ozone season. The existing text of part 75 does not specify a LME NO_X emission threshold for non-Acid Rain subpart H units that report emissions data on a year-round basis.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed to revise paragraph (a) of § 75.19 to more clearly state the LME applicability criteria for Acid Rain Program units and non-Acid Rain subpart H units. The revisions would make a distinction between sources that report emission data on a year-round basis and those that report data only during the ozone season. These changes were proposed to help owners and operators of non-Acid Rain Program units to more easily determine whether a unit can qualify for LME status. EPA proposed to clarify what the LME thresholds are for Acid Rain Program units and subpart H units.

EPA also proposed to make a minor revision to the definition of a LME unit in § 75.19(a)(1) by removing from the definition the terms ''gas-fired'' and ''oil-fired'' and adding a parenthetical, ''(i.e., diesel fuel or residual oil)'' after the words, ''fuel oil''. The Agency did not propose to expand the use of LME methodology beyond units that burn fuel oil and natural gas.

c. What Changes Is EPA Finalizing?

EPA received substantive comments on the proposed clarification of the applicability of the LME methodology, requesting that the criteria to qualify for LME status be made less restrictive. In response to these comments, today's rule increases the NO_X low mass emissions threshold for year-round reporters from 50 to less than 100 tons per year and increases the NO_X low mass emissions threshold for ozone season-only reporters from 25 to 50 tons per ozone season. For units that choose to (or are required to) report emissions data on a year-round basis, no more than 50 tons of the annual NO_X limit may be emitted during the ozone season. Today's rule also revises the definition of a ''low mass emissions unit'' in § 72.2 , expanding the applicability of the LME provisions to include units that burn gaseous fuels other than natural gas.

Discussion

Two commenters requested that EPA raise the NO_X emission thresholds for LME qualification (KeySpan Corporation (KeySpan); PSEG Fossil LLC (PSEG)). One commenter recommended raising the annual NO_X threshold to 100 tons per year, noting that many peaking units emit less than 100 tons of NO_X per year and that such units are often unmanned, making it difficult to properly maintain and operate continuous monitoring systems (KeySpan). Another commenter asked EPA to consider raising the LME threshold for ozone season-only reporters to 100 tons per ozone season (PSEG). In response to these recommended rule changes, EPA performed additional data analysis to see if raising the LME thresholds for NO_X could be justified, consistent with the principles EPA articulated in the 1998 rule for limiting eligibility to use LME. The results of that data analysis showed that raising the annual NO_X threshold from 50 to under 100 tons per year and increasing the ozone season threshold from 25 to 50 tons per ozone season are both defensible and consistent with the Agency's original intent, and accomplish Clean Air Act objectives. In the October 27, 1998 final rule, Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone (63 FR 57485), EPA laid out the applicability criteria for LMEs and initially concluded that NO_X thresholds as high as those adopted today would result in inappropriate types of sources being able to use LME, and in too many tons of NO_X emissions being exempted from CEMS. However, based on the extensive data EPA has subsequently collected under the Acid Rain Program and the Ozone Transport Commission (OTC) NO_X Budget Program, and in response to numerous persuasive source-specific petitions as well as comments on the proposed rulemaking, EPA has re-assessed its position in 1998, and now concludes that a cutoff of less than 100 tons NO_X per year, no more than 50 tons of which may be emitted in any ozone season, is both defensible and reasonable, as discussed below.

There are a number of reasons that the Agency is electing to reopen this issue at this time. First, a considerable number of units that currently are not subject to the Acid Rain Program (ARP), and thus part 75 monitoring, will be required to continuously monitor their emissions under part 75 as a result of the implementation of the NO_X SIP Call. These units include a number of smaller existing units that Congress explicitly exempted from the Acid Rain Program under title IV of the Act. Some of these turbines currently monitor under the provisions of the OTC NO_X Budget Program, generally by using default monitoring approaches, while others are located in other NO_X SIP Call States. In addition, these units include units less than 25 MWe that some OTC States have included in their NO_X SIP Call programs, as well as non-EGUs that are covered by the NO_X SIP Call. In some States, these units become subject to part 75 monitoring as early as the 2002 ozone season as part of the States' implementation of their NO_X SIP Call-related programs. These non-Acid Rain Program units face the expenditure of considerable resources to measure a rather limited portion of the total NO_X emissions.

Also, many new units being built to fulfill increased electricity demand are unmanned, gas-fired turbines with low NO_X burner technology. These units, in many cases, will be required to account for emissions under State implementation plans to reduce NO_X in the NO_X SIP Call regions of the eastern United States. Unlike units with add-on technologies (such as selective catalytic reduction (SCR)) where continual oversight is required to maintain low emissions performance, these units reliably operate at a low and consistent emissions level. Consequently, the degree of confidence the Agency can have in the attainment of overall program goals has increased, while the risks associated with underestimation of emissions from these units appears less significant. For unmanned sites, the use of CEMS provides additional challenges for owners and operators and these concerns are an additional reason for the Agency to evaluate the LME provisions.

In evaluating the LME provisions, the Agency has established a de minimis test as an internal program check to assure that only a de minimis level of emissions from all regulated sources are allowed to use exemptions from the Acid Rain Program or monitoring methods under Part 75 (including the new unit exemption, appendix E and LME provisions). In the October 27, 1998 **Federal Register**, when the Agency last considered this issue (63 FR 57486), the de minimis evaluation was based on, among other things, projections of the cumulative effect of the new National Ambient Air Quality Standards (NAAQS) for ozone (O3), NO_X SIP Call, Phase II of the ARP, and other State and regional programs (such as the OTC). The 1998 preamble established a one percent de minimis threshold of about 20,000 tons per year, covering all CEMS-exempted methods, on the basis of preliminary information which indicated that future NO_X emissions after implementation of these various CAA programs would be approximately two million tons per year. This de minimis threshold constituted a revision of the approximately 40,000 ton level EPA had originally discussed in the 1993 rule for CEMS-exempted methods.

Since that time, the Agency has developed updated information on projected year 2010 emissions from the utility sector. First, in 1999, pursuant to the CAA Amendments EPA published its section 812 prospective study of benefits under the CAA (Final Report to Congress on Benefits and Costs of the Clean Air Act, 1990 to 2010, EPA 410–R–99–001). This document estimates that total utility emissions would be approximately 3.7 million tons per year in 2010. The analysis assumes implementation of the NO_X SIP Call in the entire OTAG modeling domain. In fact, the SIP Call covers only a portion of the OTAG region (excluding States in EPA Region 1 (ME, NH, and VT), Region 4 (FL and MS), Region 5 (MN and WI), Region 6 (AR, LA, OK, and TX), Region 7 (IA, KS, NE), and Region 8 (ND and SD). Since that report, EPA has updated its estimates for 2010 post-CAA implementation NO_X emissions, and, as of October 2001, estimates approximately 4.3 million tons of NO_X per year after implementing major CAA programs such as Phase II of the Acid Rain Program and the NO_X SIP Call (see Docket No. A–2000–33, Item IV–A–7). As a result of this updated information, EPA believes that the de minimis analysis should reflect current projections and start with a one percent target level of 43,000 total tons for CEMS-exempted methods.

As indicated in the 1998 rulemaking, the Agency's determination of the appropriate level of NO_X emissions to be considered de minimis needs to be based on ''all units that may be covered by the de minimis exceptions from the requirement to use CEMS, i.e. all units using the new unit exemption, appendix E, and the new low mass emissions methodology'' (63 FR 57486). Because considerably more information on these regulated sources is now available, the Agency undertook a reevaluation of the potential number of various units that may choose excepted methodologies to account for their emissions rather than installing CEMS (see Docket No. A–2000–33, Item IV–A–6).

EPA's recent analysis (Docket No. A–2000–33, Item IV–A–6) shows that as of December 2001, there were 763 exempt new units. This total is significantly higher than the 1998 projection of 278 units. These units, based on EPA's tons per unit estimate developed in 1993 for the new unit exemption (see 58 FR 3590, January 11, 1993), have estimated emissions of approximately 8,700 tons. Exempt units are those new units under the Acid Rain Program that are less than or equal to 25 MWe and burn clean fuel with low sulfur content.

The next class of units subject to the de minimis threshold are units that monitor based on appendix E of part 75. These appendix E units are gas-or oil-fired peaking units. At the end of the year 2000, there were 263 appendix E units, and those units emitted slightly more than 14,000 tons of NO_X per year. In the 1998 preamble, EPA used 1997 data to show that there were approximately 235 units that used appendix E and that these units had approximately 11,000 tons of NO_X per year.

Finally, we examined the number of units that could potentially qualify for LME status under the new NO_X thresholds. We conducted the analysis for both ARP units and non-ARP units that will become subject to part 75 under the NO_X SIP Call. For this analysis, we used emissions data from the ARP and OTC programs and data from the NO_X SIP Call baseline inventories to evaluate multiple years of emissions data for each unit. We assumed that units' actual rates would be comparable to their fuel- and unit-specific tested emissions rates as allowed for under the LME provisions except for units with rates less than 0.15 lb/mmBtu, where we used 0.15 lb/mmBtu as a default given the requirements in § 75.19. The other assumptions and details of the analysis are included in Docket Item IV–A–6.

For Acid Rain Program units only, the change from a 50 to 100 tons of NO_X per year threshold would increase the number of existing units that could qualify by about 50 units with a total of 3,000 tons. This excludes appendix E units that already qualify for de minimis monitoring. This increase in potential LME units, taken together with emissions from appendix E units and exempt new units, would result in approximately 27,000 tons of NO_X per year subject to the de minimis target level.

For the NO_X SIP call, the increase from a threshold of 25 tons of NOX per ozone season to 50 tons per ozone season could increase the total number of existing non-ARP units that may qualify for LME by slightly more than 200 units. About 70 of those units are units in the OTC region that are under 25 MWe and currently monitor using default values under the OTC NO_X Budget Program. These units generally would also qualify for appendix E monitoring if the NO_X threshold was not increased. The total increase in tons that may be monitored using appendix E or LME provisions under an increased ozone season NO_X threshold would be approximately 2,000 tons per ozone season (an increase from about 5,500 to 7,500 tons per ozone season from these non-ARP units). Together with the estimated total of 27,000 tons per year NO_X from the ARP units, the total amount of emissions from units within the group under the de minimis concept conservatively represents approximately 35,000 tons of emissions. This total remains below the 43,000 tons target level based on one percent of projected year 2010 emissions and allows for future growth of new units that qualify for LME, appendix E, or the new unit exemption. It is also important to remember that the LME analysis accounts for units that could potentially qualify for LME monitoring requirements; not all units that potentially qualify will necessarily use the LME provisions. For example, the 1998 preamble (63 FR 57487) estimated that 224 units would qualify at the LME thresholds promulgated at that time. In the year 2000, two units used the LME provisions. Since that time, the number has increased quickly, primarily because of new turbine units that likely also would qualify for the appendix E methodology.

It is important to note that units electing alternative methodologies such as LME status and appendix E are still accountable for all their emissions using default emissions values or conservative test results. What they are relieved from is installing CEMS. The Agency was able to evaluate the long term (quarterly) emission rates for a number of units that had switched from the use of appendix E to the use of CEMS over the past few years. That study (see Docket No. A–2000–33, Item IV–A–8) examined 41 ARP units, and paired quarters from similar seasons with a minimum number of operating hours. While the lack of data from simultaneous time periods limits the ability to draw precise conclusions from this analysis, the analysis did show that the quarterly emission rates were, on average, slightly higher when units measured with appendix E rather than CEMS (approximately 4 percent). Because the appendix E and LME provisions rely on the same basic test procedures to establish a fuel- and unit-specific default rate, this analysis is relevant to the LME provisions as well. The Agency believes this analysis also supports the change in the LME thresholds that EPA is finalizing in this rulemaking by indicating that significant under-reporting of emissions should not occur as a result of using the LME provisions. We also think it provides further support for the reliability of estimates in our de minimis analysis that is based primarily on existing CEMS data for estimating the tonnage from potential LME units.

At the same time, the analysis did indicate that in particular situations, appendix E values could be below reported CEMS values. In light of this finding that appendix E (and by extension LME) monitoring will not always produce conservative values, use of alternative methods of monitoring should remain constrained by the de minimis threshold EPA has established. This finding also suggests that these monitoring methods may not be appropriate alternatives to CEMS in other programs (such as trading programs with much lower caps, or programs with short term emission limits such as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) requirements established through New Source Review permits).

Cumulatively, the data indicate that if the LME threshold were raised to 50 tons per ozone season, it would allow 95 percent of the numerous small units in the OTC NO_X Budget Program that currently use non-CEMS methodologies (which are, in many cases, similar to LME) to qualify as LME units under the NO_X Budget Trading Program. If the threshold were not raised, only about 65 percent of these same small units could qualify as LME units. EPA considers a less burdensome transition for these smaller units from the OTC Program to the larger NO_X Budget Trading Program to be highly desirable. Allowing these units to use LME methodologies under part 75 (which are similar to methodologies currently used under the OTC Program), rather than CEMS requirements under part 75, will reduce economic and administrative burden for both the affected sources and the regulatory agencies. Further, LME methodologies are reasonably accurate methods given the small amount of emissions contributed by this class of units. In view of these considerations, EPA has concluded that there are distinct benefits, and no significant environmental risks, in raising the LME qualifying NO_X thresholds to 50 tons per ozone season and less than 100 tons per year, respectively. Therefore, these higher emission threshold values are promulgated in today's rule. However, note that for units subject to the NO_X Budget Trading Program, the final rule places a constraint on the 100 tons per year NO_X limit: no more than 50 of the 100 tons per year may be emitted during the ozone season. EPA has added this constraint for purposes of consistency, so that all NO_X Budget units using the LME methodology will be limited to 50 tons of NO_X emissions per ozone season, whether data are reported on a year-round basis or only during the ozone season. In addition, should cost of monitors go down, or if the ceiling turns out to be much lower than that which we have projected herein, the Agency reserves the right to re-assess any and all of these exceptions in the future if the need arises.

Regarding the definition of a LME unit as presented in § 72.2 and in § 75.19(a), one commenter questioned why the definition appears to restrict LME qualification to units that burn only fuel oil and natural gas (UARG). The commenter suggested that the broader terms ''gas-fired'' and ''oil-fired'' be used as the criteria for determining LME applicability so that units burning ''other'' gaseous fuels, such as landfill gas, would also be allowed to use the LME methodology. After careful consideration of these comments, EPA agrees that there is no compelling reason for excluding other types of gaseous fuels from LME applicability. Further, the Agency believes that this change will reduce the administrative burden on both the sources and the regulatory agencies, by providing a way for low-emitting sources that burn ''other'' gaseous fuels to meet part 75 requirements without having to submit special petitions under § 75.66. Therefore, today's rule expands the applicability of the LME methodology to include units that burn gaseous fuels other than natural gas.

In order for a unit that burns one of these ''other'' gaseous fuels to qualify as a LME unit, fuel- and unit-specific default emission rates would have to be established. If the unit is Acid Rain-affected, § 75.19(a)(1)(i)(C) of today's rule requires the sulfur content of the fuel to be characterized by performing the 720-hour demonstration described in revised section 2.3.6 of appendix D, before the unit can qualify for LME status. The results of that demonstration may be used to determine a default SO_2 emission rate for the fuel, unless the fuel is found to have both a high sulfur content and a high sulfur variability (*i.e.,* variability with a standard deviation of greater than 5.0 grains per 100 scf); should that occur, the unit would be ineligible for LME status. To derive a default CO_2 emission factor for the fuel, revised § 75.19(c)(1)(iii) requires Equation G–4 in appendix G to be used, in conjunction with a carbon-based F-factor calculated from the results of fuel sampling and analysis. To determine the default NO_X emission rate for the gaseous fuel, revised § 75.19(c)(1)(ii) requires fuel- and unit-specific emission testing to be performed.

2. How Does Today's Rule Change the Certification Application Procedures and Requirements for Low Mass Emissions Units?

Background

a. What Is Currently Required?

In response to concerns raised by both regulated entities and other regulatory agencies, EPA examined the administrative procedures in part 75 pertaining to LME units, especially the certification application procedures. It was determined that these procedures could be clarified to simplify program implementation and to make the LME requirements as consistent as possible with other sections of part 75.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed requiring the electronic portion of the LME certification application be sent to the Administrator and the hardcopy portion to the appropriate Region and State. The Agency also proposed requiring that LME certification applications be submitted no less than 45 days prior to the date on which use of the methodology is projected to commence; and the projected commencement date be indicated in the application.

In addition, EPA proposed clarifications to the requirements for new or newly affected units and the extent to which a LME applicability demonstration could rely on projected emissions instead of actual, historical data. Finally, EPA proposed clearer definitions for the date of provisional certification for LME units.

c. What Changes Is EPA Finalizing?

Today's rule finalizes the provisions requiring submission of the LME certification application at least 45 days before the methodology is projected to be used and specification of the projected commencement date in the application. The final rule also clarifies that the methodology is considered to be provisionally certified as of the date of submittal of the certification application, but may not be used to report data prior to the projected commencement date.

In response to substantive comments regarding the initial LME certification application procedures, in particular the manner in which actual historical emissions data, projected emissions, and calculated emissions are used to demonstrate that a unit qualifies for LME status, today's rule adds significant flexibility to the way in which a unit can initially qualify. The final rule allows existing units to claim LME status using projected emissions rather than historical data, if a Federally enforceable permit restriction is taken which limits unit operation, or if the owner or operator has recently installed emission controls on the unit.

Today's rule also simplifies the application procedure by removing from § 75.19(a)(2) the requirement that the certification application must include calculated emissions for the previous three years in addition to the actual historical data for those years. For purposes of the initial certification application, the final rule allows the owner or operator of a new unit to use conservatively high default NO_X emission rates other than the values listed in Table LM–2 to project the unit's emissions.

Discussion

EPA received no comments on the proposed changes and clarifications to the LME administrative processes. Therefore, these provisions have been finalized, with only minor editorial changes for added clarity and consistency. However, two commenters objected to the manner in which an existing unit qualifies for LME status, believing it to be overly restrictive (West Virginia Manufacturers Association, PSEG). The rule requires three years or ozone seasons of historical data to demonstrate that the unit is a LME. The commenters objected to this provision because it automatically excludes units if their recent historical NO_X emissions have been above the LME thresholds, even if the source owner or operator is willing to take an enforceable permit restriction on the number of operating hours in future years. Both commenters recommended that § 75.19 be revised to conditionally allow existing units to qualify for LME status prospectively, rather than retrospectively. A third commenter objected to the apparent requirement in § 75.19(a)(2)(i) for new units to use the generic NO_X default emission rates from Table LM–2 to project the unit's NO_X emissions in the initial certification application (Machaver). The commenter recommended that EPA allow the use of a conservative but more realistic estimate of the unit's emissions (*e.g.,* the permitted NO_X emission limit or 0.15 lb/mmBtu for units with add-on controls) for the purpose of the initial certification application.

After consideration of these comments, EPA has revised the requirements for a unit to initially qualify as a LME unit. The revisions to § 75.19(a) affect both new and existing units. The final rule allows the owner or operator to claim LME status for a unit in the following ways:

1. Using three years (or ozone seasons) of actual data from electronic data reporting (EDR) submittals under part 75 or under the OTC NO_X Budget Program or, if such reports are unavailable, using estimates of the actual emissions from other sources of information (including default emission rates, emission rates derived from stack testing or part 60 CEMS, fuel sampling results, fuel usage records); or

2. Based on three years (or ozone seasons) of projected emissions for new units with no actual, historical data; or

3. Using a combination of actual and projected emissions totaling three years (or ozone seasons), if :

(a) Three years (or ozone seasons) of actual emissions data cannot be provided (e.g., for a unit that has been in operation for only one or two years); or

(b) An existing unit takes a Federally enforceable permit restriction on unit operating hours in order to stay below the LME emission thresholds; or

(c) The emissions during any of the three previous years (or ozone seasons) are not representative of present or future emissions because the owner or operator has recently installed emission controls on the unit.

Section 75.19(a)(4) of today's rule also allows the owner or operator of a new unit to use default NO_X emission rates other than the ones in Table LM–2 to project the unit's emissions in the initial certification application. The final rule allows the use of estimated NO_X emission rates which are lower than the Table LM–2 values, provided that the estimates are still conservatively high with respect to the expected actual emission rates. For instance, for a new gas-fired turbine that uses selective catalytic reduction (SCR) to control NO_X emissions, an estimated emission rate of 0.15 lb/mmBtu could be used in lieu of the Table LM–2 generic default of 0.7 lb/mmBtu. For units that use water/steam injection or dry low-NO_X (DLN) technology, an emission rate based on the permit limit could be used. For units without NO_X emission controls, the emission rate estimate could be based on historical emission test data. However, § 75.19(a)(4) makes it clear that these estimated NO_X emission rates are to be used only for the purposes of the initial certification application. The estimated emission rates may not be used for reporting purposes in the time period extending from the first hour in which the LME methodology is used to the date and hour in which the actual emission rate is established by fuel- and unit-specific emission testing. During that interval, either the Table LM–2 value or the maximum potential emission rate must be reported. EPA believes that these new provisions in § 75.19(a)(4) will ensure that new units are not unfairly excluded from using the LME methodology and will also provide a strong incentive to the owners or operators to perform the NO_X emission rate testing in a timely manner.

EPA notes that when the initial estimate of NO_X emission rate for the LME certification application is derived from historical emission test data, it may be prudent to base the estimate on data collected under process operating conditions (e.g., heat input rate, unit load.) comparable to those at which the highest NO_X emission rates are expected to occur during the four-load appendix E test. This will help to ensure that the unit's LME status is not jeopardized since the estimated NO_X emission rate will likely be close to the actual default emission rate that is derived from the appendix E testing and used for emissions reporting.

3. How Will Today's Rule Affect the Way in Which Fuel- and Unit-Specific NO_X Emission Rates Are Determined for Low Mass Emissions Units?

Background

a. What Is Currently Required?

The low mass emissions methodology in § 75.19 provides two options for determining the appropriate default NO_X emission rate for a unit. The owner or operator may either use a generic default emission rate from Table LM–2, or determine a fuel- and unit-specific default NO_X emission rate by performing emission testing, using appendix E test methodology. If the testing option is selected, § 75.19(c) specifies how to determine the default emission rate. For uncontrolled units, the default emission rate is the highest rate obtained from the emission testing, multiplied by 1.15. The reason for the 1.15 multiplier is to prevent underestimation of emissions, since the NO_X emission rate can vary at a given load. For units with NO_X emission controls of any kind, the default emission rate is the higher of: (a) the highest rate from the emission testing multiplied by 1.15; or (b) 0.15 lb/mmBtu. The reason for specifying a ''floor'' emission rate value of 0.15 lb/mmBtu for units with NO_X emission controls is principally to ensure that large units with a high potential to emit and with controls such as SCR and selective non-catalytic reduction (SNCR) would not use the LME provisions to estimate emissions. Units with these controls can achieve emissions rates much lower than 0.15 lb/mmBtu and therefore would not want to use the 0.15 lb/mmBtu floor under the LME provisions to report their emissions. EPA believes that for units with such controls, continuous NO_X emission monitoring is the preferred way to determine that a unit achieves its target control level. This is because the NO_X emission reductions achieved with these controls can vary significantly with the manner in which the controls are operated and the manner of proper operation is difficult to document and demonstrate.

After promulgating the LME provisions on October 27, 1998, EPA continued to investigate the causes of variability in NO_X emission rates in combustion turbines by reviewing literature, reviewing test results, analyzing CEMS data for turbines, and 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 (40 CFR 60.335).

EPA also investigated the claims of industry representatives who asked the Agency 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 had 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 was within acceptable limits would not underestimate emissions. To substantiate these claims, EPA reviewed data from CEMS installed at turbines with water-and-steam injection and water/fuel emulsion. As a result of this review, EPA concluded that if the water-to-fuel ratio is monitored, effective and constant control of NO_X will be achieved, with little chance of underestimation of NO_X emissions (*see* Docket A–2000–33, Item II–B–1).

b. What Changes Were Proposed?

As a result of these two investigations, EPA proposed the following revisions to § 75.19(c) on June 13, 2001. First, EPA proposed adding a new requirement for certain turbines to correct measured NO_X concentrations to ambient conditions of temperature, pressure, and relative humidity at the time of the emission test. This proposed correction (Equation LM–1a in § 75.19(c)(1)(iv)(A)(4)) would apply only to uncontrolled diffusion flame style turbines. It 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. It also would prevent underestimation or overestimation of NO_X emissions for uncontrolled diffusion flame turbines and would remove the requirement to multiply the measured NO_X emission rates for such turbines by 1.15.

Second, EPA proposed revising § 75.19(c)(1)(iv)(H)(1) to allow the use of measured fuel- and unit-specific NO_X emission rates for units with water or steam injection (and no other type(s) of add-on NO_X controls), even if the measured emission rates are below 0.15 lb/mmBtu. This proposed change would remove the current rule requirement that all tested emission rates below 0.15 lb/mmBtu must be adjusted upward to a default value of 0.15 lb/mmBtu. The proposed change would require 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.

c. What Changes is EPA Finalizing?

EPA received numerous substantive comments on the proposed changes to § 75.19(c). Based on these comments, the Agency finalizes the proposed revisions to § 75.19(c)(1)(iv)(A)(4) with only minor editorial changes, but modifies the proposed changes to § 75.19(c)(1)(iv)(H)(1). Today's rule requires fuel- and unit-specific NO_X emission rates for uncontrolled diffusion flame turbines to be corrected to ISO standard conditions, and removes the requirement to multiply the tested emission rates by 1.15. The final rule also allows units that use steam (or water) injection and have no other add-on controls, or DLN technology and have no other add-on controls, to use the highest tested emission rate for reporting purposes during controlled hours instead of reporting 0.15 lb/mmBtu. Units equipped with SCR or SNCR controls still must report the ''floor'' NO_X emission rate of 0.15 lb/mmBtu if it is higher than the tested emission rates, with one exception: if the unit uses steam (or water) injection or DLN technology in addition to the SCR or SNCR controls, then the highest tested emission rate may be reported for controlled hours in lieu of reporting 0.15 lb/mmBtu, provided that the emission testing is performed either upstream of the SCR (or SNCR) or at a time when the SCR (or SNCR) is not in operation.

Discussion

Two commenters objected to the provision requiring units that use NO_X emission controls other than water or steam injection to adjust their tested emission rates upward to 0.15 lb/mmBtu (Clean Air Energy; Exelon Corporation (Exelon)). In particular, the commenters noted that for combustion turbines using DLN control technology, the 0.15 lb/mmBtu ''floor'' emission rate is several orders of magnitude higher than the guaranteed emission levels from such units. One of the commenters recommended that EPA treat turbines with DLN control in the same manner as turbines that use water or steam injection (Exelon). That is, EPA should allow the highest tested emission rate to be reported during hours in which parametric data are available to document proper operation of the DLN controls. The commenter provided supplementary information, suggesting parameters that could be monitored to ensure that the DLN is operating in the low-NO_X, or premixed, mode.

Based on the supplementary information provided by the commenter and discussions with turbine experts (see Docket A–2000–33, Item IV–A–1), EPA has decided to incorporate the commenter's suggestion to treat LME units with DLN technology in the same manner as LME units with water-and-steam injection. Today's rule allows the highest emission rate from the appendix E tests to be reported as the default NO_X emission rate for the unit, if proper operation of the emission controls is documented. Section 75.19(c)(1)(iv)(H) of the final rule specifies that for DLN technology, ''proper operation'' of the emission controls means that the unit is in the low-NO_X or premixed combustion mode and fired with natural gas. Evidence of operation in the low-NO_X or premixed mode is provided by monitoring the appropriate turbine operating parameters. These parameters may include percentage of full load, turbine exhaust temperature, combustion reference temperature, compressor discharge pressure, fuel and air valve positions, dynamic pressure pulsations, internal guide vane (IGV) position, and flame detection or flame scanner condition. The acceptable values and ranges for all parameters monitored must be specified in the monitoring plan for the unit, and the parameters must be monitored during each unit operating hour. If one or more of these parameters is not within the acceptable range or at an acceptable value in a given operating hour, or if the unit is fired with oil, the fuel- and unit-specific NO_X emission rate may not be used for that hour and the appropriate default NO_X emission rate from Table LM–2 must be reported, instead.

Two commenters recommended that EPA revise §§ 75.19(c)(1)(iv)(C)(*4*) and (c)(1)(iv)(C)(*6*) to allow units with NO_X emission controls of any kind to use the Federally-enforceable permit limit to determine the default NO_X emission rate for an LME unit, and then to use the required periodic testing under title V of the CAA to verify that the emission limit is being met (Class of '85 Regulatory Response Group (Class of '85); Reliant Energy (Reliant)). EPA did not incorporate the commenters' suggested approach, although the Agency notes that today's rule provides some relief to controlled units from the requirement to use 0.15 lb/mmBtu as the default emission rate when the tested NO_X emission rates are less than 0.15 lb/mmBtu. In the final rule, that requirement applies only to units that use SCR or SNCR for NO_X emission control. In all other cases, LME units with NO_X emission controls may use their highest tested emission rate as the default value during controlled hours.

For add-on controls such as SCR or SNCR, proper operation of the controls depends on whether the desired chemical reaction necessary to reduce NO_X emissions is actually occurring which, in turn, depends on many factors (*e.g.,* whether the catalyst is active, whether the reagent injection rates are appropriate). Other than direct measurement of emissions using a CEMS or reference method, there is no known way to ensure that the catalyst or injected reagents are producing the expected emission reductions. Periodic title V emission testing, as recommended by the commenter, would not provide adequate assurance that the SCR or SNCR controls are operating properly on a continuous basis; because the test is ''periodic,'' at best it shows these controls are working when the test is being performed. Therefore, the final rule retains the requirement to use the 0.15 lb/mmBtu ''floor'' NO_X emission rate for units equipped with SCR or SNCR. EPA notes, however, that if a unit uses SCR (or SNCR) and steam/water injection, the final rule allows the highest tested emission rate (provided it is less than 0.15 lb/mmBtu) to be used in lieu of 0.15 lb/mmBtu, if the steam/water injection is operational during the emission testing and if the testing is either performed upstream of the SCR (or SNCR) or with the SCR (or SNCR) not operating. Similarly, for a unit that controls NO_X emissions using DLN technology and SCR (or SNCR), the highest tested emission rate may be used provided that it is less than 0.15 lb/mmBtu, and the testing is performed when DLN technology is in use and the SCR (or SNCR) is not operating (*see* §§ 75.19(c)(1)(iv)(C)(*7*) and 75.19(c)(1)(iv)(C)(*8*)).

4. Does Today's Rule Allow Testing To Be Done at Fewer Than Four Load Levels To Determine Fuel- and Unit-Specific NO_X Emission Rates for Low Mass Emissions Units?

Background

a. What Is Currently Required?

The current LME provisions in § 75.19(c)(1)(iv)(A) require testing at four load levels, using the test methodology in appendix E of part 75, for all units which opt to determine a default fuel- and unit-specific NO_X emission rate. Industry representatives have asked that this requirement be waived for units which operate at a single load only.

b. What Changes Were Proposed?

In the June 13, 2001 proposed rule, EPA proposed and solicited comments on two options as alternatives to the four load testing requirement for LME units. Option 1 would require the first appendix E test to be performed at four loads, with future single load re-tests at the load level at which the highest emission rate was found. Option 2 would allow single-load testing for units that provide a demonstration that the unit operates at a single load level.

In the preamble to the proposed rule, EPA expressed a preference for Option 2. Therefore, the Agency proposed adding a new section, (I), to § 75.19(c)(1)(iv) which is consistent with Option 2. The proposed revisions would conditionally allow single-load testing to be performed if the owner or operator demonstrates that the unit has operated at a single load level for at least 85 percent of the time in the three years prior to the emission test. Turbines that operate at a set-point temperature and not at a particular load level would also be conditionally allowed to perform single level testing, if it can be demonstrated that the unit has operated within ± 10 percent of the set-point temperature for at least 85 percent of the time in the three years prior to the emission test. EPA also proposed in § 75.19(c)(1)(iv)(I) that for a set-point turbine which normally operates at base load but is capable of operating at a higher (peak) load level, if the emission testing is only performed at base load, then the fuel- and unit-specific NO_X emission rate obtained from the testing would have to be adjusted upward during peak load operation by using a multiplier of 1.15 to ensure that emissions are not underestimated.

c. What Changes Is EPA Finalizing?

EPA received numerous substantive comments on the proposed options for reducing the number of required load levels at which testing is required to determine fuel- and unit-specific NO_X emission rates for LME units. After carefully considering these comments, the Agency has decided to incorporate both of the proposed Options 1 and 2 into the final rule. These provisions are found in §§ 75.19(c)(1)(iv)(I) and (J) of today's rule. EPA notes that Option 2 has been modified somewhat from the proposal. The final rule allows testing of LME units to be performed at either one, two, or three loads instead of four, based on the results of a historical load analysis for the previous three years (or three ozone seasons for sources that report emissions data only for the ozone season). The testing is required at however many load levels cumulatively represent at least 85 percent of the unit operating hours in the previous three years (or ozone seasons).

Discussion

One commenter supported proposed Option 2, but requested that EPA allow the demonstration of single-load operation to be made using only ozone season data for sources that report data on an ozone season-only basis (Massachusetts Department of Environmental Protection (Massachusetts DEP)). Another commenter favored Option 1 over Option 2, because Option 2, although ''reasonable,'' could only be used by a subset of LME units (NorthWestern Energy & Communications Solutions (NorthWestern)). Two commenters recommended that EPA allow testing to be done at two loads if historical load data for the unit demonstrate consistent operation at two load levels for at least 85 percent of the time (Massachusetts DEP, Machaver).

EPA has decided to include both proposed Options 1 and 2 in today's rule. The Agency believes that this provides sufficient flexibility for the various types of LME units to allow them to qualify for reduced testing requirements. The final rule incorporates the suggestion of the commenters to allow the 85 percent criterion to be applied on a cumulative operating load basis, *i.e.,* perform the testing at the number of load levels that cumulatively account for 85 percent of the unit operating hours in the three years prior to the emission test. Today's rule also allows the historical load analysis to include only ozone season data for sources that report emissions on an ozone season-only basis. These new rule provisions are found in §§ 75.19(c)(1)(iv)(I) and (J).

C. Quality Assurance/Quality Control

1. What Changes to the Method of Determining the NO_X MPC, MEC, Span, and Range Are Finalized in Today's Rule?

Background

a. What Is Currently Required?

In recent years EPA has received many questions, pertaining especially to new combustion turbines, about the way in which the maximum potential concentration (MPC) and maximum expected concentration (MEC) are determined for NO_X and how the instrument span and range values are set for NO_X monitors. Some of the questioners have requested additional options for MPC and MEC determinations and claim that part 75 does not address dry low-NO_X (DLN) control technology, which is being used on many new turbines. Others have questioned the appropriateness of the default NO_X MPC value of 50 ppm in Table 2–2 of appendix A for new oil- and gas-fired combustion turbines.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed to add new options for determining the NO_X MPC and MEC values, principally with combustion turbines in view. The proposed rule would allow the owner or operator to use a reliable estimate of the unit's uncontrolled emissions obtained from the manufacturer as the MPC value. For units that have add-on emission controls or that use DLN technology, the Federally-enforceable permit limit could be used as the MEC.

EPA also proposed replacing the 50 ppm default NO_X MPC value in Table 2–2 for new combustion turbines 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. EPA believes, based on a preliminary data analysis of emissions from new combustion turbines, that 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 (*see* Docket A–2000–33, Item II-B–1).

c. What Changes Is EPA Finalizing?

EPA received no adverse comments on these proposed rule changes. Therefore, today's rule finalizes as proposed the new options for determining NO_X MPC and MEC, and the 150 ppm and 200 ppm default MPC values for new combustion turbines. The final rule also incorporates two important changes to the general approach for determining MPC, MEC, span, and range based on recommendations made by the commenters. First, today's rule allows CEMS data from a monitor certified under 40 CFR part 60 or under a State program to be used to make the initial MPC or MEC determinations. Second, for units with a dual span requirement for SO_2 or NO_X, the final rule places an upper limit on the full-scale range setting of the low-scale analyzer in cases where the owner or operator selects the default high range option in lieu of operating and maintaining a high monitor range. Today's rule restricts the full-scale range of the low-scale analyzer to five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm).

Discussion

Two commenters supported the proposed new option to allow the use of a reliable manufacturer's estimate of a unit's uncontrolled emissions as the MPC value (UARG; Dynegy, Inc. (Dynegy)). No comments were received on the proposal to use the permit limit as the MEC for a unit with emission controls, and no comments were received on the proposed default MPC values for new combustion turbines. Therefore, in the absence of adverse comments these provisions are finalized for the reasons stated in the proposal. While these rule changes could require owners and operators of combustion turbines currently using the 50 ppm NO_X MPC value from Table 2–2 of appendix A to change their MPC and span values, the Agency believes that many have already done so in their required annual re-evaluations of span, range, MPC, and MEC values for each monitor. In other words, the owners and operators of new combustion turbines using the 50 ppm MPC value from Table 2–2 have likely found, upon analysis of actual data, that the value is unrealistically low and requires upward adjustment. The Agency expects that this rule change will primarily affect new units, rather than existing units. However, since there may be some existing units still using the 50 ppm MPC value, and since span changes may require new calibration gases to be purchased and, in some instances, may necessitate analyzer replacement, EPA has provided additional time in the rule language from the effective date of today's rule for owners and operators to implement the new MPC provision (*see* Section V., Rule Implementation, of this preamble).

EPA received additional comments on the span and range provisions of part 75. Two of these, provided by the same commenter (Machaver), are incorporated into the final rule. The commenter asked EPA to consider expanding the range of methods for establishing an initial MPC or MEC value. The commenter stated that especially for newly-affected units, the use of ''reasonable, relevant, and appropriate'' data, such as CEMS data from a part 60 monitor or historical emission test data, should be allowed. EPA believes that this suggestion has merit, particularly in view of the many sources that will soon be required to implement the monitoring provisions of part 75 under the NO_X SIP Call. Therefore, today's rule allows any available quality-assured CEMS data (whether from a part 75 monitor, a part 60 monitor, or one that meets State requirements) to be used for the initial MPC and MEC determinations. In as much as these initial determinations are self-correcting (*i.e.,* appendix A §§ 2.1.1.5 and 2.1.2.5 require an annual review) and there are sufficient incentives to ensure proper specification (*i.e.,* exceeding a full-scale range necessitates substitution of conservative emissions factors under appendix A § 2.1.2.5(b)), the Agency sees no harm introduced by providing this additional flexibility. The new rule provision is found in sections 2.1.1.1(b), 2.1.1.2(c), 2.1.2.1(e), and 2.1.2.2(c) of appendix A. Application of these data is limited to these initial MPC and MER determinations. Continuous emission monitoring systems used for part 75 reporting must meet the certification and ongoing quality assurance requirements of part 75.

The commenter also recommended that EPA set an upper limit on the low-scale measurement range for dual span units using the ''default high range'' option. For sources that elect to use the default high range option, it is advantageous to set the range of the low measurement scale as high as possible to capture emission ''spikes'' and to minimize reporting the default high range value of twice the MPC. However, if the low range is set inappropriately high, this will result in the majority of the data being recorded at the bottom end of the measurement scale during normal, controlled, unit operation. Data accuracy suffers at the low end of a measurement scale due to a poor signal-to-noise ratio. To help ensure that this does not happen, the commenter recommended capping the low-scale range at five times the MEC, where the MEC is rounded to the nearest 10 ppm. EPA concurs with this suggested approach. Today's rule adds the provision to sections 2.1.1.4(g) and 2.1.2.4(f) of appendix A.

2. What Changes to the 7-Day Calibration Error Test Are Finalized?

Background

a. What Is Currently Required?

The 7-day calibration error test described in sections 6.3.1 and 6.3.2 of appendix A of part 75 is required only for initial certification, recertification, and occasionally as a diagnostic test. It is not a routine, required, periodic quality assurance (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 sometimes infrequent or unpredictable nature of peaking unit operation, the 7-day test may take weeks or even months to complete.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed revising the 7-day calibration error test requirement for monitors installed on peaking units, requiring data to be recorded with the unit operating for only three of the seven test days. The unit would not be required to be operating for the other four days of the test.

c. What Changes Is EPA Finalizing?

EPA received numerous comments on the proposed revisions to the 7-day calibration error test procedure. After carefully considering the comments, the Agency has decided to remove the 7-day calibration error test requirement for peaking units and for SO_2 and NO_X monitors with span values of 50 ppm or less. If a unit should lose its peaking status, it would also lose its 7-day calibration error test exemption. The owner or operator would then be required to perform diagnostic 7-day calibration error tests of all installed monitors by December 31 of the following year. Today's rule reflects these changes, in sections 6.3.1 and 6.3.2 of appendix A and in § 75.20(c).

Discussion

EPA received comments from five different commenters on the proposed revisions to the 7-day calibration error test. Four of the commenters found the scope of the proposed change to be too narrow as it only applies to peaking units (UARG, Dynegy, KVB, Machaver). One commenter stated the opinion that part 75 data quality would not be jeopardized if the 7-day calibration error test were eliminated for peaking units, if not for all units (Dominion). Two other commenters provided the following suggestions: (1) Eliminate the 7-day calibration error test for all units; or (2) allow combustion turbines to perform the test off-line for all 7 days; or (3) restrict the test to zero-level calibrations for combustion turbines (UARG, Dynegy). Finally, two commenters noted that many monitoring systems cannot pass the 7-day test using the proposed methodology, i.e., using a combination of off-line and on-line calibrations, because of differences in temperature and pressure between off-line and on-line conditions (UARG, Machaver).

EPA rejected the commenters' suggestion to eliminate the 7-day calibration error test for all affected units. The Agency believes that the test has value for frequently operated units, and the test can, in most instances, be completed in seven consecutive calendar days. The purpose of the 7-day test is to ensure that from day-to-day, a continuous emission monitor does not drift excessively while it is measuring emissions at stack conditions (*e.g.,* stack pressure and temperature). The test provides a one-time demonstration that a monitor is capable of consistently passing daily calibrations at a specification twice as stringent as the allowable calibration error for daily monitor operation. Monitors that cannot meet this requirement are disqualified for use under part 75. When the test can be completed in seven consecutive days, it achieves its purpose.

EPA considered removing the 7-day calibration error test requirement for all combustion turbines, as suggested by the commenters. However, the Agency did not incorporate the commenters' recommendation since many combustion turbines are operated as base-load or cycling units. Because such units operate frequently, the 7-day calibration error test is appropriate and must be performed.

EPA rejected the commenter's suggestion to allow combustion turbines to perform the 7-day calibration error test while the unit is off-line. Performing the test off-line defeats the purpose of the test, which, as previously noted, is to assess the calibration drift of a monitor over a 7-day period while it is in thermal equilibrium with its stack environment. The Agency also rejected the commenter's recommendation to perform only a calibration with zero-level gas on each day of the test. EPA does not believe that it is technically justifiable to perform only half of the normal daily calibration sequence and to omit the other half. However, EPA does agree with the commenters who pointed out that performing the 7-day test using a combination of off-line and on-line calibrations would not be a viable solution for many monitoring systems.

In view of these considerations, EPA has decided to remove the 7-day calibration error test requirement for peaking units and also for SO_2 and NO_X monitors with span values of 50 ppm or less. With regard to peaking units, the Agency's decision is based principally on the difficulties associated with performing the 7-day calibration error test in a timely manner for such units. Because peaking units operate infrequently, it is often difficult to complete a 7-day calibration error test within a reasonable time since the test must be done with the unit in operation. In cases where a 7-day calibration error test may take several weeks or months to complete, the test loses its meaning. Today's rule specifies that a peaking unit remains exempt from the 7-day calibration error test requirement as long as it continues to re-qualify as a peaking unit from year-to-year or from ozone season-to-ozone season. However, if at the end of a particular year or ozone season peaking unit status is lost, the owner or operator must then perform diagnostic 7-day calibration error tests of all continuous emission monitors installed on the unit by December 31 of the following year.

EPA's decision to exempt SO_2 and NO_X monitors with span values of 50 ppm or less from the 7-day calibration error test is consistent with changes made in today's rule to section 2.1.4(a) of appendix B. As discussed below, the final rule lowers the allowable calibration error for daily monitor operation to 5 ppm for SO_2 and NO_X monitors with span values less than or equal to 50 ppm. Since the alternate performance specification in section 3.1 of appendix A for the 7-day calibration error test of SO_2 and NO_X monitors is also 5 ppm, the changes to appendix B will, in effect, require SO_2 and NO_X monitors with span values less than or equal to 50 ppm to meet the 7-day calibration error test specification every day. This makes it unnecessary to perform 7-day calibration error testing on these monitors.

3. What Changes to the QA/QC Requirements for Low-Emitting Sources Are Finalized?

Background

a. What Is Currently Required?

Part 75 requires owners and operators of units with SO_2 and NO_X monitors to perform daily calibration error tests of these monitors. The allowable calibration error is currently 5 percent of the span value. However, section 2.1.4(a) in appendix B of part 75 provides an alternate daily calibration specification for low emitters of SO_2 and NO_X. The alternate low-emitter specification (for span values less than 200 ppm) is 10 ppm, 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 needs to be tightened. This is especially important because many new gas turbines are being built and these units have very low NO_X emissions, often in the 0–10 ppm range.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed to 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 between 50 and 200 ppm. However, 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. Also, 5 ppm is the alternate calibration error performance specification in section 3.1(b) of appendix A for initial certification of SO_2 and NO_X monitors.

c. What Changes Is EPA Finalizing?

EPA received only one comment on the proposed modification of the alternate calibration error specification. The comment was supportive (Clean Energy Group). Therefore, today's rule finalizes the proposed change to section 2.1.4(a) of appendix B lowering the daily calibration error specification to 5 ppm for SO_2 and NO_X monitors with span values of 50 ppm or less.

4. What Changes to the Stack Flow-to-Load Ratio Test Are Finalized?

Background

a. What Is Currently Required?

In the May 26, 1999 rule revisions, EPA added a new quarterly QA test for flow monitors to part 75: the flow-to-load ratio test. Since promulgation, EPA has received many questions about the test 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.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed revising the flow-to-load test methodology by allowing the data exclusions listed in section 2.2.5(c) of appendix B to be taken 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 would clarify the issue of co-firing as it pertains to data exclusions. Units that co-fire different fuels as part of normal operation could claim flow-to-load test data exclusions for hours in which fuels were not co-fired, if the reference flow relative accuracy test audit (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 also clarify the instructions for multiple stack configurations and allow the data to be analyzed 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.

c. What Changes Is EPA Finalizing?

EPA received supportive comments from one commenter on the proposed revisions to the flow-to-load ratio test methodology (UARG). No adverse comments were received. Therefore, today's rule finalizes the changes for the reasons stated in the proposal.

5. What Special QA Provisions Are Finalized for Units That Do Not Produce Electrical Output or Steam Load?

Background

a. What Is Currently Required?

Units subject to the monitoring and reporting requirements of part 75 must account for their emissions on a continuous basis. Most units use 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 annually thereafter.

Section 6.5.1 of appendix A to part 75 requires that RATAs of gas monitors be done at a single "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.

Under the NO_X SIP Call, some sources that do not produce electrical output or steam load, such as cement kilns or refinery process heaters, 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.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed to revise section 6.5.2.1 of appendix A to part 75 by adding a method of establishing the proper operating levels at which to perform RATAs for units that do not produce electrical output or steam load (e.g., cement kilns and process heaters).

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.

Once the boundaries of the range of operation are established and the normal operating load level 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.'' The 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.

c. What Changes Is EPA Finalizing?

EPA received adverse comments on the proposed approach to determining the range of operation, normal operating level, and flow RATA requirements for non-load-based units, i.e., units that do not produce electrical output or steam load. After careful consideration of these comments, EPA has modified the proposed approach. The requirement to define the range of operation and the low, mid, and high operating levels in terms of stack gas velocity (ft/sec) is being finalized in this action, with only one minor change: the owner or operator may use 0.0 ft/sec as the ''minimum potential velocity.'' However, EPA is not adopting the proposed requirement to perform a historical analysis of flow rate data to establish the ''normal'' operating level. Instead, today's final rule specifies that the normal operating level for a non-load-based unit is determined using sound engineering judgment and operating experience with the unit and process, and supported with documentation in the monitoring plan. In addition, new section 6.5.2(e) of today's rule allows the owner or operator of a non-load-based unit to obtain relief from three-load flow RATA testing, if an acceptable technical justification is provided in the monitoring plan. If the owner or operator can satisfactorily demonstrate that the process operates only at one level, then only single-level flow RATAs would be required for certification and on-going quality assurance. If the process is demonstrated to operate at two distinct levels, then two-level flow RATAs would be required.

Discussion

EPA received comments from only one commenter regarding the proposed method of determining range of operation, normal operating level, and the appropriate operating levels for flow RATAs (APCA). The commenter stated two objections to the proposed rule provisions: (1) that the ''maximum potential velocity'' approach is not applicable to cement kilns; and (2) that since cement kilns operate at one level, only single-level flow RATAs should be required.

EPA does not agree with the commenter's claim that the concept of maximum potential velocity cannot be applied to a cement kiln. The Agency notes that the commenter did not explain why the proposed methodology will not work for cement kilns. EPA believes that for any non-load-based unit, an estimate of the highest stack gas velocity during normal operation should be easily obtainable, using EPA Method 2 (see 40 CFR 60, Appendix A). However, EPA has reconsidered the proposed approach to determining the normal operating level and establishing the RATA levels for flow monitors installed on such units. For industrial processes, such as cement manufacturing, which often have only one distinct operating level, it may not be appropriate to require a historical data analysis to establish the normal operating level, or to require three-level flow RATAs to be performed.

In view of these considerations, today's rule finalizes the requirement for non-load-based units to define the range of operation in terms of stack gas velocity as proposed. However, the velocity information is only used to define the operating range and the low, mid, and high operating levels. EPA is not adopting the proposed requirement for non-load-based units to determine the normal operating level by analyzing historical flow rate data. Instead, today's rule requires that the normal operating level be established using sound engineering judgment and process operating experience. Regarding the appropriate number of levels for flow RATAs, today's rule requires non-load-based units to perform flow RATA testing at the same number of load levels as are specified for load-based units in section 2.3.1.3(c) of appendix B (i.e., three levels for certification, two levels for routine quality-assurance) unless the owner or operator submits a technical justification to the permitting authority with the hardcopy of the initial monitoring plan for the unit, demonstrating that the unit operates at only one level. Today's rule adds this option in a new paragraph, (e), to section 6.5.2 of appendix A. The technical justification must include appropriate documentation and data to demonstrate that the process operates at only one level. If the justification is acceptable to the permitting authority, then only single-level flow RATAs would be required for initial certification, recertification, and on-going quality assurance. For non-load-based processes that operate at only two distinct levels, section 6.5.2(e) allows a similar justification to be submitted as an option to the three-level flow RATA testing.

D. Appendix D

1. What Changes to the Definitions of ''Pipeline Natural Gas'' and ''Natural Gas'' Are Finalized?

Background

a. What Is Currently Required?

The definitions of ''pipeline natural gas'' and ''natural gas'' in § 72.2 state that a gaseous fuel must meet a two-fold requirement to qualify as one of these fuels: the fuel must meet a hydrogen sulfide (H_2S) content limit (0.3 gr/100 scf for pipeline natural gas and 1.0 gr/100 scf for natural gas) and the H_2S must constitute at least 50 percent of the fuel's total sulfur content. Appendix D of part 75 does not explain how to comply with the second of these two requirements (*i.e.,* the H_2S as a percentage of total sulfur). Further, industry members have expressed concern 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 over the definitions of pipeline natural gas and natural gas, EPA issued interim guidance on June 12, 2000, discussing how sources could demonstrate compliance with the existing definitions (see Docket A–2000–33, Item IV–A–5). As explained in the guidance, through its authority under § 75.66, EPA would allow owners or operators to comply by meeting a total sulfur limit (0.6 gr/100 scf for pipeline natural gas or 2.0 gr/100 scf for natural gas), in lieu of documenting that H_2S constitutes at least 50 percent of the total sulfur content.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed revising 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. The proposed total sulfur content values would be 0.5 gr/100 scf for pipeline natural gas and 20.0 gr/100 scf for natural gas. The value of 20.0 gr/100 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.

For fuels that qualify as pipeline natural gas, a default SO_2 emission rate of 0.0006 lb/mmBtu would be used to quantify SO_2 emissions, and for fuels that qualify as natural gas, a default SO_2 emission rate would be calculated based on Equation D–1h in appendix D. Equation D–1h would be revised and based upon the total sulfur content of the fuel, rather than the H_2S content.

c. What Changes Is EPA Finalizing?

EPA received no adverse comments on the proposed revisions to the definitions of pipeline natural gas and natural gas. Therefore, today's rule finalizes the revised definitions as proposed.

Discussion

EPA received comments from four commenters on the proposed revisions to the definitions of pipeline natural gas and natural gas (Class of '85, XCEL Energy, Clean Energy Group, UARG). All four commenters favored the proposed changes. One commenter noted that eliminating the hydrogen sulfide content limit would make the use of appendix D more attractive and would reduce the risk of unintentional violations of the monitoring requirements (Class of '85). In view of these supportive comments, EPA finalizes the proposed definitions of pipeline natural gas and natural gas without modification.

2. How Does Today's Rule Change the Method by Which a Gaseous Fuel Qualifies As ''Pipeline Natural Gas'' or ''Natural Gas''?

Background

a. What Is Currently Required?

The part 75 requirements for demonstrating that a particular gaseous fuel qualifies as pipeline natural gas or natural gas are found in sections 2.3.1.4 and 2.3.2.4 of appendix D. Compliance with the hydrogen sulfide content limit must be documented through one of five sources of information: (1) a fuel purchase or pipeline transportation contract; (2) vendor certification based on fuel sampling; (3) one year of monthly sampling; (4) one year of sampling each shipment or lot of fuel (for fuels delivered in shipments or lots); or (5) a demonstration consisting of 720 hours of sampling.

b. What Changes Were Proposed?

As discussed in the previous question, on June 13, 2001, EPA proposed revising the definitions of pipeline natural gas and natural gas by removing the specified limits on the hydrogen sulfide content of the fuel and replacing them with limits on total sulfur content.

EPA also proposed revisions to sections 2.3.1.4 and 2.3.2.4 of appendix D, which would change the way of documenting that a fuel qualifies as pipeline natural gas or natural gas. An initial compliance demonstration and periodic sampling of the total sulfur content of the fuel would be required. Initial compliance with the total sulfur limit would be documented either: (1) using a fuel purchase or pipeline transportation contract; or (2) using the results of all available fuel sampling results for the previous 12 months; or (3) using the results of a 720-hour demonstration; or (4) by obtaining and analyzing a sample of the fuel in the absence of a contract or historical fuel sampling data. Once a fuel initially qualified as pipeline natural gas or natural gas, periodic, on-going sampling for total sulfur content would be required. The proposed sampling frequency was semiannual and whenever ''it is reasonable to believe that the fuel composition has changed significantly.''

c. What Changes Is EPA Finalizing?

EPA received numerous comments on both the proposed method by which a fuel qualifies as pipeline natural gas or natural gas and the proposed semiannual total sulfur sampling requirement. In view of the comments, EPA has modified these rule provisions. In today's rule, revised sections 2.3.1.4 and 2.3.2.4 of appendix D specify three methods by which a fuel may initially qualify as pipeline natural gas or natural gas: (1) by a fuel contract or tariff sheet with a maximum total sulfur specification that meets the definition of pipeline natural gas or natural gas; (2) based on historical fuel sampling and analysis data from the previous twelve months; or (3) in the absence of a satisfactory contract specification or historical sampling data, by obtaining a sample (or samples) of the fuel. For a fuel that qualifies using a contract or tariff sheet specification, no additional on-going sampling of the total sulfur content is required, provided that the contract or tariff sheet is current, valid, and representative of the fuel combusted in the unit. For a fuel that initially qualifies as pipeline natural gas or natural gas based on fuel sampling and analysis, total sulfur sampling is required annually and whenever the fuel supply changes. The annual total sulfur sampling requirement has an effective date of January 1, 2003.

Discussion

One commenter supported the proposed provision to allow a fuel to initially qualify as pipeline natural gas or natural gas based on a single fuel sample, and also supported the proposed semiannual total sulfur sampling requirement (Reliant). Another commenter expressed concern that for sources using the historical fuel sampling option, the language requiring that ''all available fuel samples'' from the past twelve months be used could require an exhaustive search of all possible sources of sample results and might lead to allegations that a source had excluded relevant samples (UARG). The commenter suggested that EPA should consider using alternate language, such as ''representative fuel samples from the past twelve months'', and that the Agency should also allow averaging of sample results. The commenter also stated that if a source has followed EPA's June 12, 2000 guidance and has obtained the total sulfur sample(s) to document that the fuel being combusted qualifies as pipeline natural gas or natural gas, re-qualification is unnecessary and the source should only be subject to the on-going semiannual fuel sampling requirements.

Three commenters objected to the proposed requirement to sample the total sulfur content of pipeline natural gas and natural gas semiannually (UARG, Class of '85, XCEL Energy). One of these commenters suggested that annual, rather than semiannual, sampling would be more appropriate, and that for sources relying on a contract specification, the on-going sampling should not be required at all (UARG). The other two commenters recommended deleting the semiannual sampling requirement and requiring re-sampling only if the fuel supply changes (Class of '85, XCEL Energy). Several commenters stated that EPA should allow immediate re-sampling to be performed if the results of a periodic sulfur sample analysis are believed to be anomalous or suspect (Class of '85, XCEL Energy, Machaver).

After considering these comments, EPA has revised both the requirements for a fuel to initially qualify as pipeline natural gas or natural gas, and the on-going total sulfur sampling requirements. In today's rule, revised sections 2.3.1.4 and 2.3.2.4 of appendix D provide three methods by which a fuel may qualify: (1) By a total sulfur specification in a fuel contract or tariff sheet; (2) based on historical fuel sampling data from the previous twelve months; or (3) in the absence of a contract specification or historical sampling data, a sample of the fuel's total sulfur content must be obtained and analyzed. Note that EPA has removed the fourth option of performing the 720-hour demonstration described in section 2.3.6 of appendix D to qualify, believing it to be unnecessary in light of the third option allowing use of a sample. The 720-hour demonstration has been reserved for characterizing the sulfur content of gaseous fuels other than pipeline natural gas and natural gas.

Today's rule states that when the owner or operator relies on the specifications in a fuel contract or tariff sheet for a fuel to initially qualify as pipeline natural gas or natural gas, no initial or on-going sampling of the total sulfur content is required, provided that the contract or tariff sheet is current, valid, and representative of the fuel combusted in the unit. For a fuel that initially qualifies as pipeline natural gas or natural gas based on fuel sampling and analysis, total sulfur sampling is required annually and whenever the fuel supply changes. The annual total sulfur sampling requirement has an effective date of January 1, 2003.

EPA believes that most sources are likely to use fuel sampling to demonstrate that the fuel qualifies as pipeline natural gas or natural gas, rather than relying on contract specifications. This is because the maximum total sulfur content specified in most contracts for transmitting pipeline natural gas, and under most tariffs established with the Federal Energy Regulatory Commission, is 20.0 gr per 100 scf, whereas the actual total sulfur content of natural gas is generally 10 to 100 times lower. In the absence of actual fuel sampling data, Table D–5 in appendix D requires the maximum total sulfur content specified in the contract or tariff to be used to calculate the default SO_2 emission rate. Therefore, EPA believes that most sources combusting natural gas will elect to perform fuel sampling, rather than using the specifications in a fuel contract or tariff sheet, in order to avoid significantly overestimating SO_2 emissions.

The final rule further states that when historical fuel sampling results are used to qualify, only those fuel samples taken by or provided to the owner or operator in the past twelve months need be considered. If multiple fuel samples are used to qualify, each sample must meet the applicable total sulfur limit. Also, if a single fuel supply serves many affected units, it is not necessary to obtain a separate sample for each unit, provided that no other gaseous fuel is mixed with the fuel in transporting it from the sampling location to the affected units. For fuels that qualify as natural gas, if multiple samples are taken, the results may be averaged before using Equation D–1h to calculate the default emission rate.

If the results of any required fuel sampling and analysis fail to demonstrate that a fuel qualifies as pipeline natural gas or natural gas, but the results are suspect or believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan and additional sampling may be initiated immediately. In such cases, at least three additional samples are required and each sample analysis must meet the applicable total sulfur limit for pipeline natural gas or natural gas.

Finally, EPA notes that affected facilities currently relying on total sulfur samples obtained in accordance with the June 12, 2000 guidance to meet the definition of pipeline natural gas or natural gas are not required to perform any additional sampling to re-qualify, provided that the fuel supply source has not changed since the samples were taken. These facilities are subject only to the on-going, annual total sulfur sampling requirement which takes effect in 2003.

3. How Does Today's Rule Change the Fuel Sampling and Data Reporting Requirements for Gaseous Fuels Other Than Pipeline Natural Gas and Natural Gas?

Background

a. What Is Currently Required?

Appendix D of part 75 may be used for ''other'' gaseous fuels besides pipeline natural gas and natural gas. For these other gaseous fuels, appendix D does not allow SO_2 emissions to be quantified using a default SO_2 emission rate. Rather, hourly sampling of the total sulfur content of the fuel is required using manual sampling methods or an on-line gas chromatograph, although section 2.3.6 in appendix D provides a

720-hour demonstration procedure whereby some relief from hourly sulfur sampling can be obtained. The demonstration requires 720 hours of sampling to characterize the fuel's total sulfur content and variability. If the results of the demonstration show that the fuel has a low sulfur variability, then the owner or operator may sample the fuel's sulfur content daily instead of hourly.

b. What Changes Were Proposed?

In the June 13, 2001 proposed rule, EPA proposed clarifying that the 720-hour demonstration procedure in section 2.3.6 of appendix D is optional and that it may be used to show that the sulfur content of a particular gaseous fuel is within the limits for pipeline natural gas or natural gas. However, the Agency received a significant comment on section 2.3.6, requesting that EPA allow the demonstration procedure to be used to determine default SO_2 emission factors for gaseous fuels such as refinery gas and producer gas, so that units burning these fuels would be able to obtain relief from the hourly or daily sulfur sampling requirements.

c. What Changes Is EPA Finalizing?

EPA believes that the commenter's suggestion has merit, and has incorporated it into the final rule. Today's rule conditionally allows the owner or operator of an Acid Rain Program unit that combusts a gaseous fuel other than pipeline natural gas or natural gas to determine a fuel-specific default SO_2 emission rate using the results of the 720-hour demonstration in section 2.3.6 of appendix D. The default emission rate could be used in conjunction with the hourly heat input rate to quantify hourly SO_2 emissions in the same manner as is done for pipeline natural gas or natural gas. The only exception to this would be if the results of the 720-hour demonstration indicate that the gaseous fuel has both a high sulfur content and high sulfur variability (i.e., greater than 5.0 grains per 100 scf, standard deviation). In that case, the more rigorous hourly sulfur sampling would be required.

Discussion

EPA received one comment on the proposed changes to section 2.3.6 of appendix D (UARG). The commenter requested that EPA add language to section 2.3.6 stating that for ''other'' low-sulfur gaseous fuels (such as producer gas, refinery gas, and landfill gas), the results of the 720-hour demonstration in section 2.3.6 may be used to determine a fuel-specific default SO_2 emission rate such as is determined for natural gas by using Equation D–1h. The principal reason for this recommended rule revision would be to provide regulatory relief from the current appendix D requirement to perform either hourly or daily sulfur sampling for these ''other'' gaseous fuels.

EPA finds the commenter's request to be reasonable and believes that the 720-hour demonstration is sufficiently representative to support the desired regulatory relief with little risk of underestimating SO_2 emissions. Therefore, today's rule adds the requested language to section 2.3.6 of appendix D. In the final rule, revised section 2.3.6 conditionally allows ''other'' gaseous fuels (e.g., refinery gas or producer gas) to use default SO_2 emission rates to quantify SO_2 mass emissions rather than performing daily or hourly sampling for total sulfur. If the 720-hour demonstration described in section 2.3.6 is performed for the gaseous fuel, the results of that demonstration may be used to determine a default SO_2 emission rate, provided that the fuel is not found to have both a high sulfur content (more than 20 grains per 100 scf) and a high sulfur variability (more than 5 grains per 100 scf, standard deviation). If the fuel qualifies to use a default SO_2 emission rate, then Equation D–1h in appendix D may be used to calculate the emission rate in the same manner that a default emission rate would be calculated for natural gas. The exact value of the fuel's total sulfur content used to calculate the default emission rate depends on whether the fuel is found to have a low or high sulfur variability (i.e., variability with a standard deviation of greater than 5.0 grains per 100 scf) during the 720-hour demonstration. If the sulfur variability is low, the 90th percentile value from the demonstration is used in the calculation. If the sulfur variability is high, the maximum value from the demonstration is used to calculate the default SO_2 emission rate.

Today's rule requires periodic on-going total sulfur sampling for other gaseous fuels that use the demonstration in section 2.3.6 to determine a default SO2 emission rate. The required sampling frequency is annual. For reporting purposes, the default emission rate derived from the 720-hour demonstration is used unless a higher sulfur content is obtained in an annual sample, in which case the higher sampled value would be reported.

The Agency notes that the 720-hour demonstration in section 2.3.6 may also be used to derive fuel-specific default SO_2 emission rates for Acid Rain Program units seeking to qualify as low mass emissions units under § 75.19 (see Docket A–2000–33, Item V–C–1 for further discussion).

4. What Changes to the Appendix D Missing Data Procedures Are Finalized?

Background

a. What Is Currently Required?

Appendix D requires the owner or operator to report substitute data for any hour in which quality-assured fuel flow rate data is not obtained and whenever a sample of the fuel sulfur content, gross calorific value, or density has not been obtained and analyzed as required. The load-based missing data procedures for fuel flow rate are found in section 2.4 of appendix D. The appropriate substitute data values for fuel sulfur content, gross calorific value, and density are given in Table D–6.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed revising the appendix D missing data procedures. The load-based fuel flow rate missing data procedures in section 2.4.2 would be clarified but not substantively changed. New fuel flow rate missing data procedures would be added for units that do not produce electrical output or steam load. The missing data requirements for the sulfur content of gaseous fuels in Table D–6 would also be changed, as follows: (1) Substitute data values for pipeline natural gas and natural gas would be expressed in terms of the total sulfur content of the gas instead of the hydrogen sulfide content; (2) for pipeline natural gas, the substitute data value would be 0.002 lb/mmBtu; (3) for natural gas, the substitute data value would be an emission rate (in lb/mmBtu) calculated from Equation D–1h using the lesser of the maximum total sulfur content specified in the fuel contract or 1.5 times the highest total sulfur value from the previous year's samples; (4) 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; and (5) for gaseous fuels sampled hourly, the substitute data value would be the highest total sulfur content from the previous 720 hourly samples.

c. What Changes Is EPA Finalizing?

Today's rule finalizes the revisions to the appendix D missing data procedures. The final rule provisions have been modified somewhat from the proposal to be consistent with changes that have been made to other sections of appendix D based on comments received. The fuel flow rate missing data procedures for non-load-based units have also been simplified to make them easier to implement. EPA has provided additional time in the rule language from the effective date of today's rule for owners and operators to implement these new missing data routines (see Section V., Rule Implementation, of this preamble).

Discussion

EPA received comments on the proposed revisions to the appendix D missing data routines from only one commenter (UARG). The commenter was generally supportive of the proposed changes to the gas sulfur content substitute data values in Table D–6 and to the missing data routines for fuel flow rate. However, the commenter expressed concern that the changes would require significant reprogramming of the data acquisition and handling system (DAHS) software and requested that EPA allow sufficient time to implement the new missing data routines.

In view of the supportive comments received, the proposed revisions are finalized with only minor changes. These changes to the proposal are deemed necessary for purposes of consistency. Other sections of appendix D have been modified based on comments received, and some of the changes to those sections impact the missing data routines. The most significant change was made to the substitute data value for natural gas combustion. The proposed rule would have required the substitute data value to be the lesser of: (a) the maximum sulfur content specified in the fuel contract; or (b) 1.5 times the highest sulfur content from the previous year's samples. The final rule requires the substitute data value to be 1.5 times the default value of sulfur content which is in effect at the time of the missing data period. According to revised Table D–5, the default value ''in effect'' will be either the maximum sulfur content specified in the fuel contract or the sulfur content from the most recent sample. Since the required sampling frequency for natural gas is annual, only one sample is required each year. Thus, there is little difference in meaning between the proposed rule language, *i.e.,* ''highest sulfur content from the previous year's samples'' and the final rule language, *i.e.,* ''sulfur content from the most recent sample.''

Today's rule finalizes the proposed fuel flow rate missing data routines both for load-based units and for units that do not produce electrical or steam load. The load-based provisions are finalized as proposed; however, for ease of implementation the proposed non-load-based routines have been simplified. In the final rule, the substitute data value for non-load-based units is simply the arithmetic average of the quality-assured flow rates in a 720-hour lookback period. EPA is not finalizing the proposed option that would have allowed the data to be sorted into operating bins, nor the associated text in section 4 of appendix C. The Agency believes that separating fuel flow data into operating bins unnecessarily complicates the missing data routines. EPA expects that not finalizing this proposed missing data option will have little or no impact since, at present, there are no non-load-based oil and gas-fired units required to use part 75 monitoring. However, it is possible that such units may be included in a future program such as the Federal NO_X Budget Trading Program. Should the owners or operators of such units elect to use appendix D and decide that operational bins are needed for fuel flow rate missing data purposes, EPA will consider allowing that missing data approach through the petition process under § 75.66.

E. Other Highlights and Changes

1. What Changes to the Compliance Dates and Timelines for Monitor Certification in § 75.4 Are Finalized in Today's Rule?

Background

a. What Is Currently Required?

Part 75 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 provides greater flexibility.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed to harmonize all of the timelines 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, section 126 final rule in order to make the certification timelines in parts 75 and 97 consistent.

c. What Changes Is EPA Finalizing?

Today's rule finalizes the proposed changes to the certification timelines in parts 75 with one exception. For newly-affected Acid Rain Program units under § 75.4(c), the certification timeline would begin with the first hour of operation of the unit after the date on which it becomes an Acid Rain-affected unit, rather than the first hour after the unit becomes Acid Rain-affected.

Discussion

EPA received numerous comments on the proposed changes to the certification timelines in § 75.4 (Reliant, Clean Energy Group, Dominion, UARG, Class of '85, Dynegy). All of the commenters were supportive of the proposed revisions. However, one commenter requested that § 75.4(c) be revised further (Dominion). The commenter recommended that the timeline for newly-affected Acid Rain Program units be modified so that the ''clock'' starts with the first hour of commercial operation of the unit after it becomes affected, rather than starting from the date and hour on which the unit becomes affected. The commenter indicated that this would provide the utility with the option of not operating a newly-acquired unit, thereby allowing time to acquire the necessary CEMS equipment. EPA agrees that this added flexibility in the certification timeline for newly-affected units is desirable and incorporates the commenter's suggestion into the final rule.

2. Does Today's Rule Change the Way in Which Unit and Stack Operating Hours Are Counted?

Background

a. What Is Currently Required?

Part 75 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 not 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.

b. What Changes Were Proposed?

On June 13, 2001, EPA proposed to add two new definitions, ''cumulative stack operating hours'' and ''cumulative unit operating hours'', 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. These proposed changes would effectively remove the requirement to count partial operating hours as full hours when determining the source operating time and the length of the grace period.

c. What Changes Is EPA Finalizing?

EPA is finalizing neither of the proposed definitions of ''cumulative stack operating hours'' and ''cumulative unit operating hours'' nor the proposed changes to the way in which unit and stack operating hours are counted.

Discussion

EPA received input from four commenters on the proposed changes to the method of counting unit and stack operating hours (Class of '85, Dynegy, UARG, XCEL Energy). None of the commenters supported the changes without reservation. All of them indicated that EPA should make the changes optional, not mandatory. All of the commenters stated that the changes would require significant, potentially costly changes to the DAHS software. The commenters also noted that for many utilities, the increase in rule flexibility associated with the changes would not be great enough to justify the expense.

In the absence of fully supportive comments, EPA has decided not to adopt the proposed revisions. The Agency considered incorporating the commenters' suggestion to allow two options for calculating source operating time, i.e., one based on unit operating hours and one based on ''cumulative'' unit operating hours. However, EPA rejected this approach because it would seriously complicate program oversight. It also would require significant re-programming of EPA's data checking software and would require structural changes to several EDR record types. In this case, the Agency concludes that the relatively small benefit of allowing a second method of calculating source operating time does not justify the associated cost.

3. Does Today's Rule Change the Notification Requirements for Monitor Certifications and Recertifications?

Backround

For the initial certification of continuous monitoring systems, part 75 requires the owner or operator to provide a minimum of 45 days advance notice before the first date of scheduled testing. For recertifications, at least 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).

On June 13, 2001, EPA proposed revising §§ 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. EPA believed the existing 7-day notice for partial recertifications provided too little time for State and local agency personnel and EPA personnel to schedule site visits to observe the recertification testing. Conversely, the Agency believed that 45 days notice was too far in advance of the testing. 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.

Based on comments received, EPA is finalizing the 21-day certification test notification requirement as proposed, but has modified the proposed recertification test notification provisions. Today's rule makes a clearer distinction between full and partial recertifications and the notification requirements for each type. The final rule reduces the notification requirement for full recertifications from 45 to 21 days as proposed, but retains the 7-day advance notice requirement for partial recertifications. An emergency provision for unplanned full recertifications has also been added to § 75.61(a)(1)(i).

Discussion

EPA received comments from five commenters on the proposed changes to the certification and recertification test notification requirements (Dominion, Dynegy, UARG, Class of '85, ESC). The commenters did not object to reducing the test notification time for initial certifications from 45 to 21 days. However, four of the commenters objected to the proposal to require 21 days advance notice for recertifications (Dominion, Dynegy, UARG, ESC), and the fifth commenter objected to the 7-day notification requirement when the scheduled RATA is performed on a different date (Class of '85). The commenters perceive the 21-day notification requirement for recertifications as being an increase from the 7-day requirement of the current rule. For reasons discussed in greater detail in the ''Response to Comments'' document supporting this rulemaking (see Docket No. A–2000–33, Item V–C–1), this perception is not entirely correct. The proposed 21-day notification requirement represents an increase in notification time only for partial recertifications (where a full battery of tests is not required). For full recertifications, where all of the tests are required, 21 days notice actually is a reduction from the 45-day notification requirement of the current rule.

The commenters' main objection to the 21-day notification requirement for recertifications centers around emergency (unplanned) events that require recertification. The commenters expressed concern that requiring such a long advance notice would require sources in emergency situations to postpone testing in order to give observers the opportunity to schedule site visits. The commenters stated that this could result in sources having to use the missing data routines for long periods of time which is inconsistent with the part 75 goal of keeping monitors operating and reducing missing data episodes.

After consideration of these comments, EPA is finalizing the 21-day test notification requirement for initial certifications and for full recertifications. The text of § 75.61(a)(1)(i) is revised to be consistent with § 75.20(b)(2) and to make it clear that the 21-day requirement applies to full recertifications as well as initial certifications. A typographical error in § 75.20(b) is also corrected. The proposed 21-day notification for partial recertifications is not adopted, and the 7-day requirement, with the associated emergency provision, is retained.

To address the commenters' concern about emergency recertifications, § 75.61(a)(1)(i) of today's rule provides an emergency provision for unplanned events beyond the source operator's control which require a full battery of recertification tests to be performed. The emergency provision is the same as the one in § 75.61(a)(1)(ii) for partial recertifications.

4. Does Today's Rule Affect the Way in Which Emissions Are Monitored and Reported for Units With Bypass 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 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.

On June 13, 2001, EPA proposed clarified and expanded instructions for SO_2 and NO_X monitoring of multiple and bypass stack configurations in §§ 75.16(c) and 75.17(c), and in § 75.72(c) and (d). EPA proposed a new provision to §§ 75.17(c) and 75.72(c) for configurations consisting of a main stack and a bypass stack, allowing the maximum potential NO_X emission rate to be reported when the bypass stack is used.

EPA also proposed revisions to 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. Proposed § 75.16(c)(3) 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.

Today's rule finalizes the proposed bypass stack monitoring and reporting revisions with minor editorial changes.

Discussion

Two commenters supported the proposed revisions to the bypass stack monitoring provisions (UARG, Reliant). However, one of the commenters objected to the proposed language in §§ 75.16(c) and 75.17(c) addressing the reporting of parameters other than SO_2 or NO_X during bypass hours, stating that the proposed language ''creates confusion and conflict'' (UARG).

After consideration of these comments, EPA is finalizing the bypass stack monitoring provisions as proposed, except that the references in §§ 75.16(c) and 75.17(c) to the reporting of other parameters, such as CO_2, are not adopted because EPA believes that these requirements are adequately addressed in other sections of the rule and do not need to be re-stated here.

5. What Other Noteworthy Provisions Are Finalized in Today's Rule?

EPA notes that no negative comment was received on the following significant revisions to part 75 that are finalized for the reasons stated in the proposed rule:

- The proposal to remove the restriction in section 2.1.2 of appendix D prohibiting apportionment of measured hourly heat input at a common pipe to the individual units (for units using the provisions of subpart H of part 75 to monitor NO_X mass emissions) is finalized. Common pipe heat input apportionment is now allowed for subpart H units, provided that the units served by the pipe are all affected units with similar efficiencies (e.g., all boilers or all turbines).
- The proposed revisions to the appendix E missing data procedures are finalized.
- The proposed revisions to appendix E, section 2.2, requiring retesting once every 5 years (20 calendar quarters) and removing the requirement to retest every 3,000 operating hours are finalized.
- The proposal to expand the use of Equation G–4 in appendix G to oil-fired units is finalized.

F. Streamlining Changes

Background

A number of rule sections in part 75 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.

On June 13, 2001, EPA proposed streamlining 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 Agency proposed to remove from part 75 all of the rule sections that expired on April 1, 2000, and all textual references to those sections. This includes the recordkeeping and reporting sections, §§ 75.54, 75.55, and 75.56; the monitoring plan provisions in § 75.53(c) and (d); and the CO_2 missing data provisions in § 75.35(c).

EPA also proposed removing rule sections that only applied to Phase I Acid Rain Program units and are now inapplicable, and to remove all textual references to those sections. For instance, 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. The 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.

Today's rule finalizes the streamlining changes as proposed. EPA has prepared a technical support document (see Docket No. A–2000–33, Item IV–A–9) that identifies in tabular form all of the streamlining changes made to part 75.

Discussion

EPA received comments from only one commenter on the proposed streamlining changes to part 75 (UARG). The commenter agreed that the cited rule provisions are obsolete and did not object to their removal. Therefore, EPA finalizes the changes as proposed.

V. Rule Implementation

This final rule becomes effective July 12, 2002. However, EPA is aware that while some affected sources may choose to take advantage of options provided immediately, others will require more time for implementation. Therefore, EPA has specified in this final rule where additional time is permitted for full compliance with new mandatory requirements.

The rule provisions that provide alternative compliance dates are as follows: Appendix A paragraph 2.1.2.1(a); Appendix D Table D–6 under Gas Total Sulfur Content; and Appendix E paragraph 2.5.2.

EPA is aware that some non-load based units are required under their State's SIP to start monitoring NO_X mass emissions according to part 75 in the 2002 ozone season. EPA will continue to work with the affected sources and the State to resolve any conflicts imposed on the sources by the timing of today's rule.

Some aspects of the final rule that will require attention concern reporting requirements and mechanisms. While EPA is prepared to accept electronic data reports in the proscribed format, regulated sources will require time to review the final rule and make any adjustments or changes in software that may result. With this in mind, EPA is updating the EDR version 2.1 Instructions to accompany this final rule. EPA has identified in the rule language any deadlines for compliance that are different from the effective date of this rule, as applicable. If you have questions regarding the implementation of this final rule, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

VI. Regulatory Assessment Requirements

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency 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 final rule is not expected to have an annual effect on the economy of $100 million or more. It has been determined that this rule is not a ''significant regulatory action'' under the terms of Executive Order 12866 and it is therefore not subject to OMB review.

B. 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.

Today's rule is not expected to result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year and, as such, is not subject to sections 202 and 205 of the UMRA. As discussed in section III., above, EPA will continue to use its outreach efforts related to part 75 implementation, including guidance documents and a policy manual that is updated regularly, to inform, educate, and advise all potentially impacted governments about compliance with part 75.

C. Paperwork Reduction Act

The Office of Management and Budget (OMB) has approved the information collection requirements contained in this rule under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et. seq.* and has assigned OMB control numbers 2060–0258 and 2060–0445.

The information collection requirements in 40 CFR parts 72 and 75 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 and 75. First, the Acid Rain Program ICR (ICR 1633.12, OMB No. 2060–0258) addresses the costs for units affected by the Acid Rain Program. The NO_X SIP Call ICR (ICR 1857.02, 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 provide additional flexibilities to existing 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 changes finalized in parts 72 and 75, 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 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 rule revisions to the LME section clarify how the rule applies to non-ARP SIP Call units that use part 75 for NO_X mass monitoring. 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 from 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 and applicability of LME for Subpart H monitoring

Although not indicated in Table 1, there are two primary ways in which the parts 72 and 75 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 significant.

The second type of burden or cost increase would be associated with any required 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 rule revisions that could 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. As noted in Section V., Rule Implementation, of this preamble, sources regulated under part 75 will have additional time to comply with certain provisions. Consequently, the expected impact associated with DAHS changes is also expected to be minimal.

In the proposed rule, the Agency specifically requested comment on its assessment of information burden imposed by these requirements and received no comments on the subject. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purpose of collecting, validating, and verifying information; process and maintain information and disclose and provide information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to respond to a collection of information; search existing data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

D. Regulatory Flexibility Act (RFA) as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et. seq.

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

After considering the economic impacts of today's final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. In determining whether a rule has a significant economic impact on a substantial number of small entities, the impact of concern is any significant *adverse* economic impact on small entities, since the primary purpose of the regulatory flexibility analyses is to identify and address regulatory alternatives ''which minimize any significant economic impact of the proposed rule on small entities.'' 5 U.S.C. 603 and 604. Thus, an agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, or otherwise has a positive effect on the small entities subject to the rule. Today's final action adds flexibility to the existing procedures for monitoring and reporting and makes other streamlining improvements and clarifications to the existing regulations. The EPA has therefore concluded that today's final rule will have no adverse impacts on small entities and may relieve burden in some cases.

E. National Technology Transfer and Advancement Act

As noted in the proposed rule, section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 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, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves environmental monitoring or measurement. Consistent with the Agency's Performance Based Measurement System (''PBMS''), part 75 sets forth criteria that allow the use of alternative methods to the ones identified in part 75. The PBMS approach is intended to be more flexible and cost effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality.

EPA specifically requested public comment on any other voluntary consensus standards which may be appropriate for the part 75 rule revisions and no such comments were received. The EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however, any alternative methods must be approved through the petition process under § 75.66(c) before they may be used under part 75.

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

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: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

Today's rule is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the Agency does not have reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children.

G. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

Today's action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This final rule 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. Thus, Executive Order 13132 does not apply to this rule.

As discussed above in Section III. and in the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically worked with and solicited comment on the proposed rule from State and local officials.

H. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 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 final 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.

Moreover, as discussed above in Section III. and in the spirit of Executive Order 13175, and consistent with EPA policy to promote communications between EPA and tribal governments, EPA specifically solicited comment on the proposed rule from tribal officials.

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

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

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq*., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This rule will take affect July 12, 2002.

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, NO_X Budget Trading Program, 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 (CEM), Electric generating units (EGUs), Electric utilities, Nitrogen oxides, Non-electric generating units (Non-EGUs), Non-load based units, NO_X Budget Trading Program, Reporting and recordkeeping requirements, Subpart H, Sulfur oxides.

Dated: May 1, 2002.

Christine Todd Whitman,

Administrator.

For the reasons set out in the preamble, title 40 chapter I of the Code of Federal Regulations is 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'', ''Low mass emissions unit'', ''Missing data period'', ''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 removing the words ''or more'' at the end of the definition;

i. Removing the definition of ''Heat input'' and adding in its place a new definition ''Heat input rate'';

j. Removing the definition of ''Hour before and after'' and adding in its place a new definition of ''Hour before and Hour after'';

k. Removing the definition of ''Maximum potential NO_X emission rate'' and adding in its place ''Maximum potential NO_X emission rate or MER'';

l. Removing the definition of ''Maximum rated hourly heat input'' and adding in its place the definition for ''Maximum rated hourly heat input rate'';

m. In the definition for ''monitor accuracy'' by removing the words ''or by one of its component parts'';

n. In the definition of ''Natural gas'' by revising the second sentence, and by removing the word ''meet'' and revising the ''%'' symbol to read ''percent'' in the third sentence;

o. In the definition of ''Peaking unit'' by adding a new paragraph (4);

p. 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'';

q. Adding new definitions for ''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''.

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 (% 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 (% 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 (% H_2O)

* * * * *

Diluent cap value means a default value of percent CO_2 or O_2 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 percent CO_2 is below the default value or when the measured hourly average percent O_2 is above the default value. The diluent cap values for boilers are 5.0 percent CO_2 and 14.0 percent O_2. For combustion turbines, the diluent cap values are 1.0 percent CO_2 and 19.0 percent O_2.

* * * * *

Emergency fuel means either:

(1) * * *

(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.

* * * * *

Low mass emissions unit means an affected unit that is ''gas-fired'' or ''oil-fired'' (as defined in this section), and that qualifies to use the low mass emissions excepted methodology in § 75.19 of this chapter.

* * * * *

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 (MPC), 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. As a second alternative, when the NO_X MPC is determined from emission test results or from historical CEM data, as described in section 2.1.2.1 of appendix A to part 75 of this chapter, quality-assured diluent gas (*i.e.*, O_2 or CO_2) data recorded concurrently with the MPC may be used to calculate the MER. For the purposes of §§ 75.4(f), 75.19(b)(3), and 75.33(c)(7) in part 75 of this chapter and section 2.5 in appendix E to part 75 of this chapter, the MER is specific to the type of fuel combusted in the unit.

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.

* * * * *

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

* * * * *

Peaking unit means: * * *

(4) A unit required to comply with the provisions of subpart H of part 75 of this chapter, under a State or Federal NO_X mass emissions reduction program, may, pursuant to § 75.74(c)(11) in part 75 of this chapter, qualify as a peaking unit on an ozone season basis rather than an annual basis, if the owner or operator reports NO_X mass emissions and heat input data only during the ozone season.

* * * * *

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, 7651k, and 7651k note.

§ 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 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'', and, in paragraph (c)(2), by revising the word ''becomes'' to read ''first operates after becoming'';

b. 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'';

c. Revising paragraphs (d)(1), (f) introductory text, (f)(1), (i)(2) and (i)(3);

d. In paragraph (e) introductory text, by revising the words ''90 calendar days'' to read ''90 unit operating days or 180 calendar days (whichever occurs first)'', by removing the word ''or'' in each instance that it occurs between ''flue, or flue gas'' or ''flue or flue gas'', by adding a comma between the words ''flue'' and ''flue gas'' in the second sentence, and by adding ''or add-on NO_X emission controls'' after each occurrence of ''desulfurization system'';

e. Removing and reserving paragraph (h);

f. In paragraph (i)(1), by removing the word ''or''; and

g. Adding paragraph (j).

The revisions and additions read as follows:

§ 75.4 Compliance dates.

* * * * *

(d) * * *

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

* * * * *

(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. If the required testing is completed by this deadline, the appendix E correlation curve derived from the test results may be used for reporting data under this part beginning with the first date and hour that the backup fuel is combusted, provided that the fuel flowmeter for the backup fuel was certified as of that date and hour. If the required appendix E testing has not been successfully completed by the compliance date in this paragraph, then, until the testing is 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, as defined in § 72.2 of this chapter; or

* * * * *

(h) [Reserved]

(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.

(j) If the certification tests required under paragraph (b) or (c) of this section have not been completed by the applicable compliance date, the owner or operator shall determine and report SO_2 concentration, NO_X emission rate, CO_2 concentration, and flow rate data for all unit operating hours after the applicable compliance date in this paragraph until all required certification tests are successfully completed using either:

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

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

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

§ 75.6 [Amended]

6. Section 75.6 is amended in paragraphs (a)(17), (a)(18), (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 first occurrence of 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 adding the word ''-diluent'' after the first occurrence of the word ''NO_X'' in the first sentence; and by revising the words ''the automated'' to read ''an automated'';

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)(iii) 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'' in the first sentence 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, an 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 heading 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 by 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 colon, 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 adding the word ''-diluent'' after NO_X 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.

* * * * *

§ 75.13 [Amended]

10. Section 75.13 is amended by:

a. In paragraph (b), by revising in the heading the words ''Appendix G of'' to read ''appendix G to'', and by revising in the first sentence the words ''may provide information satisfactory to the Administrator'' to read ''shall follow the procedures in appendix G to this part''; and

b. In paragraph (c) by revising in the first sentence the word ''may'' to read ''shall'' and the words ''dry basis'' to read ''dry basis (or where Equation F–14b in appendix F to this part is used to determine CO_2 concentration), either'', and by revising the comma after the reference to ''§ 75.11(b)(1)'' to a semicolon.

§ 75.15 [Reserved]

11. Section 75.15 is removed and reserved.

12. Section 75.16 is amended by:

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

b. Removing and reserving paragraph (a);

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

d. Revising paragraph (c);

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

f. In paragraph (e)(1) by revising in the first sentence the words ''choose to install'' to read ''use the flow rate and diluent'', by removing in the first sentence the words ''wherever flow and diluent monitor measurements are used to determine the heat input,'', by revising the words ''(a) through (d)'' to read ''(b) through (d)'' in the first sentence, by revising the words ''(a)(1)(ii), (a)(2)(ii), (b)(1)(ii),'' to read ''(b)(1)(ii)'', and by adding at the end of the paragraph the words '', according to paragraph (e)(3) of this section'';

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

h. In paragraph (e)(3) by adding in the second sentence the words '', in conjunction with the appropriate unit and stack operating times'' after the words ''total steam flow for all units 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.

(a) [Reserved]

(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 may be reported instead), and the hourly volumetric flow rate value that would be substituted for the flow monitor installed on the main stack or flue under the missing data procedures in subpart D of this part if data from the flow monitor installed on the main stack or flue were missing for the hour. The maximum potential SO_2 concentration may be specific to the type of fuel combusted in the unit during the bypass (*see* § 75.33(b)(5)). The option in this paragraph, (c)(3), 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 or any other parameter that is monitored only at the main stack. Calculate SO_2 mass emissions for the unit as the sum of the emissions calculated with the substitute values and the emissions recorded by the SO_2

and flow monitoring systems installed on 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(d) 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 may be specific to the type of fuel combusted in the unit during the bypass (*see* § 75.33(c)(8)).

14. Section 75.19 is amended by:

a. Revising the section heading, paragraph (a), and paragraphs (b)(1), (b)(2), (b)(3), (b)(4)(i), (b)(5), (c)(1)(i), (c)(1)(ii), (c)(1)(iii), (c)(1)(iv)(C), (c)(3)(ii)(C), (c)(3)(ii)(D) introductory text, (c)(3)(ii)(D)(*1*), (c)(3)(ii)(E), (c)(3)(ii)(F), (c)(3)(ii)(G), (c)(3)(ii)(H), and (e)(2);

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'' and the words ''a low'' to read ''the low'';

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

d. Amending paragraph (b)(4)(iii) by revising the words ''and NO_X'' in the first sentence to read ''and/or NO_X'', revising the second sentence, and by revising the word ''The'' in the third sentence to read ''For Acid Rain Program LME units, the'';

e. In paragraph (c)(1)(iv) introductory text by adding a new sentence after the second sentence;

f. By revising in the first sentence of paragraph (c)(1)(iv)(A) the words ''(c)(1)(iv)(F) and (G) of this paragraph'' to read ''(c)(1)(iv)(F), (c)(1)(iv)(G), and (c)(1)(iv)(I) of this section'' and by adding new paragraphs (c)(1)(iv)(A)(*3*) and (*4*) and Equation LM–1a;

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

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

i. In paragraph (c)(1)(iv)(D) by revising in the first sentence the words '', each unit in a group of units sharing a common fuel supply, or'' to read ''or group of'', by adding in the first sentence the words ''(20 calendar quarters)'' after the words ''five years'', and by adding a new sentence after the second sentence;

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

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

l. Amending the first sentence of (c)(1)(iv)(H) by revising the first occurrence of the words ''NO_X emission controls,'' to read ''add-on NO_X emission controls, and for units that use dry low-NO_X technology,'';

m. Amending 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 ''that hour'';

n. Redesignating existing paragraph (c)(1)(iv)(H)(*2*) as (c)(1)(iv)(H)(*3*), and adding the words '', and the appropriate default NO_X emission rate from Table LM–2 shall be reported instead'' after the words ''that hour'' and adding new paragraph (c)(1)(iv)(H)(*2*);

o. Adding new paragraphs (c)(1)(iv)(I) and (c)(1)(iv)(J);

p. In paragraph (c)(2) introductory text by adding the words '', except that for unmanned facilities, the records may be kept at a central location, rather than on-site'' after the word ''inspection'';

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

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

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

t. In paragraphs (c)(3)(ii)(I) and (c)(3)(ii)(J) by revising the definition of variables following Equations LM–7, LM–8, LM–7a, and LM–8a;

u. In paragraph (c)(4)(i)(A) by adding the words ''(Acid Rain Program units, only)'' after the word ''unit'' in the first sentence, by capitalizing the first letter of the word ''where'', and by revising the definition of variable ''EF_{SO2}'' for Equation LM–9;

v. In paragraph (c)(4)(ii)(A) by correcting the variables ''WNO_X'' and ''$EFNO_X$'' to read ''W_{NOX}'' and ''EF_{NOX}'';

w. In paragraph (c)(4)(ii)(C) by adding a new sentence to the end of this paragraph;

x. In paragraph (c)(4)(iii)(A) by adding the words ''(Acid Rain Program units, only)'' after the word ''unit'' in the first sentence and by revising the definition of the variable ''EFCO2'' under Equation LM–11;

y. Amending paragraph (e)(5) by revising the words ''which have NO_X emission controls of any kind'' to read ''which has add-on NO_X emission controls of any kind or uses dry low-NO_X technology'';

z. Adding new paragraph (e)(6) between paragraph (e)(5) and table LM–1;

aa. Amending Table LM–2 that follows paragraph (e) by revising the words ''Boiler type'' to read ''Unit type'' in heading for the first column;

bb. Amending Table LM–3 that follows paragraph (e) by revising the words ''Natural Gas'' to read ''Pipeline (or other) Natural Gas'' in the first column; and

cc. Amending Table LM–5 that follows paragraph (e) by adding the word ''Other'' before ''Natural Gas'' in the first column 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 (LME) units.

(a) *Applicability and qualification.* (1) For units that meet the requirements of this paragraph (a)(1) and paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input and hourly NO_X, SO_2, and CO_2 mass emissions under this part.

(i) A low mass emissions unit is an affected unit that is gas-fired, or oil-fired (as defined in § 72.2 of this chapter), and for which:

(A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits:

(*1*) No more than 25 tons of SO_2 annually and less than 100 tons of NO_X annually, for Acid Rain Program affected units. If the unit is also subject to the provisions of subpart H of this part, no more than 50 of the allowable annual tons of NO_X may be emitted during the ozone season; or

(*2*) Less than 100 tons of NO_X annually *and* no more than 50 tons of NO_X during the ozone season, for non-Acid Rain Program units subject to the provisions of subpart H of this part, for which the owner or operator reports emissions data on a year-round basis, in accordance with § 75.74(a) or § 75.74(b); or

(*3*) No more than 50 tons of NO_X per ozone season, for non-Acid Rain Program units subject to the provisions of subpart H of this part, for which the owner or operator reports 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 emissions 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.

(C) This paragraph, (a)(1)(i)(C), applies only to a unit that is subject to an SO_2 emission limitation under the Acid Rain Program, and that combusts a gaseous fuel other than pipeline natural gas or natural gas (as defined in § 72.2 of this chapter). The owner or operator of such a unit must quantify the sulfur content and variability of the gaseous fuel by performing the demonstration described in section 2.3.6 of appendix D to this part, in order for the unit to qualify for LME unit status. If the results of that demonstration show that the gaseous fuel qualifies under paragraph (b) of section 2.3.6 to use a default SO_2 emission rate to report SO_2 mass emissions under this part, the unit is eligible for LME unit status.

(ii) Each qualifying LME 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 designated in the certification application as the first year that the methodology will be used; 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 designated in the certification application as the first ozone season that the methodology will be used.

(C) For a new or newly-affected unit, see paragraph (b)(4) of this section for additional guidance.

(2) A unit may initially qualify as a low mass emissions unit if the designated representative submits a certification application to use the LME methodology (as described in § 75.63(a)(1)(ii) and in this paragraph, (a)(2)) and the Administrator (or permitting authority, as applicable) 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 methodology is expected to commence, and the application must contain:

(i) A statement identifying the projected date on which the LME methodology will first be used. The projected commencement date shall be consistent with paragraphs (a)(1)(ii) and (b)(4) of this section, as applicable; and

(ii) Either:

(A) Actual SO_2 and/or NO_X mass emissions data (as applicable) for each of the three calendar years (or ozone seasons) prior to the calendar year in which the certification application is submitted demonstrating to the satisfaction of the Administrator or (if applicable) the permitting authority, that the unit emitted less than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section. For the purposes of this paragraph, (a)(2)(ii)(A), the required actual SO_2 or NO_X mass emissions for each qualifying year or ozone season shall be determined using the SO_2, NO_X and heat input data reported to the Administrator in the electronic quarterly reports required under § 75.64 or under the Ozone Transport Commission (OTC) NO_X Budget Trading Program. Notwithstanding this requirement, in the absence of such electronic reports, an estimate of the actual emissions for each of the previous three years (or ozone seasons) shall be provided, using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or procedures consistent with the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate SO_2 or NO_X 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. Alternatively, the initial estimate of the NO_X emission rate may be based on historical emission test data that is representative of operation at normal load or historical data from a CEMS certified under part 60 of this chapter or under a state CEM program; or

(B) When the three full years (or ozone seasons) of actual SO_2 and NO_X mass emissions data (or reliable estimates thereof) described under paragraph (a)(2)(ii)(A) of this section do not exist, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of actual historical SO_2 and NO_X mass emissions data and projected SO_2 and NO_X mass emissions, totaling three years (or ozone seasons). Except as provided in paragraph (a)(3) of this section, actual data must be used for any years (or ozone seasons) in which such data exists and projected data should be used for any remaining future years (or ozone seasons) needed to provide emissions data for three consecutive calender years (or ozone seasons). For example, if a 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 unit, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual 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 appropriate default emission rates from paragraphs (c)(1)(i) and (c)(1)(ii) of this section (or, alternatively for NO_X, a conservative estimate of the NO_X emission rate, as described in paragraph (a)(4) 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; and

(iii) A description of the methodology from paragraph (c) of this section that will be used to demonstrate on-going compliance under paragraph (b) of this section; and

(iv) Appropriate documentation demonstrating that the unit is eligible to use projected emissions to qualify for LME status under paragraph (a)(3) of this section (if applicable).

(3) In the following circumstances, projected emissions for a future year (or years) may be used in lieu of the actual emissions data from one (or more) of the three years (or ozone seasons) preceding the year of the certification application:

(i) If the owner or operator takes an enforceable permit restriction on the number of annual or ozone season unit operating hours for the future year (or years), such that the unit will 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; or

(ii) If the actual emissions for one (or more) of the three years (or ozone seasons) prior to the year of the certification application is not representative of the present and expected future emissions from the unit, because the owner or operator has recently installed emission controls on the unit.

(4) When the owner or operator elects to demonstrate initial LME qualification and on-going compliance using a fuel-and-unit-specific NO_X emission rate in accordance with paragraph (c)(1)(iv) of this section, there will be instances (e.g., for a new or newly-affected unit) where it is not possible to determine that NO_X emission rate prior to submitting the certification application. In such cases, if the generic default NO_X emission rates in Table LM–2 of this section are inappropriately high for the unit, the owner or operator may use a more representative, but conservatively high estimate of the expected NO_X emission rate, for the purposes of the initial monitoring plan submittal and to calculate the unit's projected annual or ozone season emissions under paragraph (a)(2)(ii)(B) of this section. For example, the NO_X emission rate could, as described in paragraph (a)(2)(ii)(A) of this section, be estimated using historical CEM data or historical emission test data that is representative of operation at normal load. The NO_X emission limit specified in the operating permit for the unit could also be used to estimate the NO_X emission rate (except for units equipped with SCR or SNCR), or, consistent with paragraph (c)(1)(iv)(C)(*4*) of this section, for a unit that uses SCR or SNCR to control NO_X emissions, an estimated default NO_X emission rate of 0.15 lb/mmBtu could be used. However, these estimated NO_X emission rates may not be used for reporting purposes in the time period extending from the first hour in which the LME methodology is used to the date and hour on which the fuel-and-unit-specific NO_X emission rate testing is completed. Rather, in that interval, the owner or operator shall either report the appropriate default NO_X emission rate from Table LM–2, or shall report the maximum potential NO_X emission rate, calculated in accordance with § 72.2 of this chapter and section 2.1.2.1 of appendix A to this part. Then, beginning with the first unit operating hour after completion of the tests, the appropriate default NO_X emission rate(s) obtained from the fuel-and-unit-specific testing shall be used for emissions reporting.

(b) *On-going qualification and disqualification.* (1) Once a low mass emissions 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 methodology described in the certification application under paragraph (a)(2)(iii) of this section.

(2) If any low mass emissions 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 emissions unit shall be disqualified from using the low mass emissions excepted methodology; and

(ii) The owner or operator of the low mass emissions unit shall install and certify monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13, and shall report SO_2 (Acid Rain Program units, only), NO_X, and CO_2 (Acid Rain Program units, only) emissions data and heat input data from such monitoring systems by December 31 of the calendar year following the year in which the unit exceeded the number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section; and

(iii) If the required monitoring systems have not been installed and certified by the applicable deadline in paragraph (b)(2)(ii) of this section, 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 potential 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 from paragraph (c)(1)(i) of this section and the maximum potential hourly unit heat input; the CO_2

emissions, in tons/hr, calculated using the applicable default CO_2 emission rate from paragraph (c)(1)(iii) of this section and the maximum potential hourly unit heat input; and the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(3) If a low mass emissions 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 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 and certify SO_2 (Acid Rain Program units, only), NO_X, and CO_2 (Acid Rain Program units, only) and flow (if necessary) monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13 prior to a change to such fuel, and shall report emissions data from such monitoring systems beginning with the date and hour on which the new fuel is first combusted in the unit. 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.

(4) * * *

(i) Keep the records specified in paragraph (c)(2) of this section, beginning with the date and hour of commencement of commercial operation, for a new unit subject to an Acid Rain emission limitation, and beginning with the date and hour of the commencement of operation, for a new unit subject to a NO_X mass reduction program under subpart H of this part. For newly-affected units, the records in paragraph (c)(2) of this section shall be kept as follows:

(A) For Acid Rain Program units, begin keeping the records as of the first hour of commercial operation of the unit following the date on which the unit becomes affected; or

(B) For units subject to a NO_X mass reduction program under subpart H of this part, begin keeping the records as of the first hour of unit operation following the date on which the unit becomes an affected unit;

* * * * *

(iii)* * * For example, use the default emission rates in table LM–1, LM–2, and LM–3 of this section or use the fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section. * * *

(5) A low mass emissions unit that has been disqualified from using the low mass emissions excepted methodology may subsequently submit an application to qualify again to use the low mass emissions methodology under paragraph (a)(2) of this section only if, following the non-compliant year (or ozone season), at least three full years (or ozone seasons) of actual, monitored emissions data is obtained showing that the unit emitted 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. Further, the designated representative or authorized account representative must certify in the application that the unit operation for the years or ozone seasons for which the emissions were monitored are representative of the projected future operation of the unit.

(c) *Low mass emissions excepted methodology, calculations, and values.* (1) *Determination of SO_2, NO_X, and CO_2 emission rates.*

(i) If the unit combusts only natural gas and/or fuel oil, use Table LM–1 of this section to determine the appropriate SO_2 emission rate for use in calculating hourly SO_2 mass emissions under this section (Acid Rain Program units, only). If the unit combusts gaseous fuel(s) other than natural gas, the owner or operator shall use the procedures in section 2.3.6 of appendix D to this part to document the total sulfur content of each such fuel and to determine the appropriate default SO_2 emission rate for each such fuel.

(ii) If the unit combusts only natural gas and/or fuel oil, use either the appropriate NO_X emission factor from Table LM–2 of this section, or a fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section, to calculate hourly NO_X mass emissions under this section. If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall determine a fuel-and-unit-specific NO_X emission rate according to paragraph (c)(1)(iv) of this section.

(iii) If the unit combusts only natural gas and/or fuel oil, use Table LM–3 of this section to determine the appropriate CO_2 emission rate for use in calculating hourly CO_2 mass emissions under this section (Acid Rain Program units, only). If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall determine a fuel-and-unit-specific CO_2 emission rate for the fuel, as follows:

(A) Derive a carbon-based F-factor for the fuel, using fuel sampling and analysis, as described in section 3.3.6 of appendix F to this part; and

(B) Use Equation G–4 in appendix G to this part to derive the default CO_2 emission rate. Rearrange the equation, solving it for the ratio of W_{CO2}/H (this ratio will yield an emission rate, in units of tons/mmBtu). Then, substitute the carbon-based F-factor determined in paragraph (c)(1)(iii)(A) of this section into the rearranged equation to determine the default CO_2 emission rate for the unit.

(iv) * * * The testing must be completed in a timely manner, such that the test results are reported electronically no later than the end of the calendar year or ozone season in which the LME methodology is first used. * * *

(A) * * *

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

(*4*) If the testing is performed on an uncontrolled diffusion flame turbine, a correction to the observed average NO_X concentration from each run of the Method 20 test must be applied using the following Equation LM–1a.

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

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 (mm Hg).

P_o = Observed atmospheric pressure during the test run (mm 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 (g H_2O/g air).

H_o = Observed humidity ratio during the test run (g H_2O/g 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 (° K).

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

(B) * * *

(*3*) [Reserved]

* * * * *

(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*) Except for LME units that use selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) to control NO_X emissions, the highest three-run average NO_X emission rate obtained at any load in the 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*) For a group of identical low mass emissions units (except for units that use SCR or SNCR to control NO_X emissions), 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 tested load from any unit tested in the group, for that type of fuel.

(*4*) Except as provided in paragraphs (c)(1)(iv)(C)(*7*) and (c)(1)(iv)(C)(*8*) of this section, for an individual low mass emissions unit which uses SCR or SNCR to control NO_X emissions, 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 three-run average emission rate from any load of the appendix E test for that type of fuel; or

(*ii*) 0.15 lb/mmBtu.

(*5*) [Reserved]

(*6*) Except as provided in paragraphs (c)(1)(iv)(C)(*7*) and (c)(1)(iv)(C)(*8*) of this section, for a group of identical low mass emissions units that are all equipped with SCR or SNCR to control NO_X emissions, 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 three-run average NO_X emission rate at any load from all appendix E tests of all tested units in the group, for that type of fuel; or

(*ii*) 0.15 lb/mmBtu.

(*7*) Notwithstanding the requirements of paragraphs (c)(1)(iv)(C)(*4*) and (c)(1)(iv)(C)(*6*) of this section, for a unit (or group of identical units) equipped with SCR (or SNCR) *and* water (or steam) injection to control NO_X emissions:

(*i*) If the appendix E testing is performed when the water (or steam) injection is in use *and* either upstream of the SCR or SNCR or during a time period when the SCR or SNCR is out of service; then

(*ii*) The highest three-run average emission rate from the appendix E testing may be used as the fuel-and-unit-specific NO_X emission rate for the unit (or, if applicable, for each unit in the group), for each unit operating hour in which the water-to-fuel ratio is within the acceptable range established during the appendix E testing.

(*8*) Notwithstanding the requirements of paragraphs (c)(1)(iv)(C)(*4*) and (c)(1)(iv)(C)(*6*) of this section, for a unit (or group of identical units) equipped with SCR (or SNCR) *and* uses dry low-NO_X technology to control NO_X emissions:

(*i*) If the appendix E testing is performed during a time period when the dry low-NO_X controls are in use, but the SCR or SNCR is out of service; then

(*ii*) The highest three-run average emission rate from the appendix E testing may be used as the fuel-and-unit-specific NO_X emission rate for the unit (or, if applicable, for each unit in the group), for each unit operating hour in which the parametric data described in paragraph (c)(1)(iv)(H)(*2*) of this section demonstrate that the dry low-NO_X controls are operating in the premixed or low-NO_X mode.

(*9*) For an individual combustion turbine (or a group of identical turbines) that operate principally at base load (or at a set point temperature), but are capable of operating at a higher peak load (or higher internal operating temperature), the fuel-and-unit-specific NO_X emission rate for the unit (or for each unit in the group) shall be as follows:

(*i*) If the testing is done only at base load, use the three-run average NO_X emission rate for base load operating hours and 1.15 times that emission rate for peak load operating hours; or

(*ii*) If the testing is done at both base load and peak load, use the three-run average NO_X emission rate from the base load testing for base load operating hours and the three-run average NO_X emission rate from the peak load testing for peak load operating hours.

(D) * * * Testing shall be done at the number of loads specified in paragraph (c)(1)(iv)(A) or (c)(1)(iv)(I) of this section, as applicable. * * *

* * * * *

(G) Low mass emissions 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 that uses SCR or SNCR for NO_X emission control, 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.

(H) * * *

(*2*) For a low mass emissions unit that uses dry low-NO_X premix technology to control NO_X emissions, proper operation of the emission controls means that the unit is in the low-NO_X or premixed combustion mode, and fired with natural gas. Evidence of operation in the low-NO_X or premixed mode shall be provided by monitoring the appropriate turbine operating parameters. These parameters may include percentage of full load, turbine exhaust temperature, combustion reference temperature, compressor discharge pressure, fuel and air valve positions, dynamic pressure pulsations, internal guide vane (IGV) position, and flame detection or flame scanner condition. The acceptable values and ranges for all parameters monitored shall be specified in the monitoring plan for the unit, and the parameters shall be monitored during each subsequent operating hour. If one or more of these parameters is not within the acceptable range or at an acceptable value in a given operating hour, the fuel-and-unit-specific NO_X emission rate may not be used for that hour, and the appropriate default NO_X emission rate from Table LM–2 shall be reported instead. When the unit is fired with oil the appropriate default value from Table LM–2 shall be reported.

* * * * *

(I) Notwithstanding the requirements in paragraph (c)(1)(iv)(A) of this section, the appendix E testing to determine (or re-determine) the fuel-specific, unit-specific NO_X emission rate for a unit (or for each unit in a group of identical units) may be performed at fewer than four loads, under the following circumstances:

(*1*) Testing may be done at one load level if the data analysis described in paragraph (c)(1)(iv)(J) of this section is performed and the results show that the unit has operated (or 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 testing. 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 the operation of the turbine, the internal operating temperature set point may be used as a surrogate for load in demonstrating that the unit qualifies for single-load testing. If the data analysis shows that the unit does not qualify for single-load testing, testing may be done at two (or three) load levels if the unit has operated (or if all units in the group of identical units have operated) cumulatively at two (or three) load levels for at least 85.0 percent of all operating hours in the previous three years; or

(*2*) If a multiple-load appendix E test was initially performed for a unit (or group of identical units) to determine the fuel-and-unit specific NO_X emission rate, then the periodic retests required under paragraph (c)(1)(iv)(D) of this section may be single-load tests, performed at the load level for which the highest average NO_X emission rate was obtained in the initial test.

(J) To determine whether a unit qualifies for testing at fewer than four loads under paragraph (c)(1)(iv)(I) of this section, follow the procedures in paragraph (c)(1)(iv)(J)(*1*) or (c)(1)(iv)(J)(*2*) of this section, as applicable.

(*1*) 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: from 20 MW to 40 MW; band #2: from 41 MW to 60 MW; band #3: from 61 MW to 80 MW; and band #4: from 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. Alternatively, for sources that report emissions data only during the ozone season, the historical load analysis may be based on unit operation in the previous three ozone seasons, rather than unit operation in the previous 12 calendar quarters. Determine the percentage of the data that fall into each load band. For a unit that is not part of a group of identical units, if 85.0% or more of the data fall into one load band, 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% criterion, then representative single-load testing within the load band may be performed. If the 85.0% criterion cannot be met to qualify for single-load testing but this criterion can be met cumulatively for two (or three) load levels, then testing may be performed at two (or three) loads instead of four.

(*2*) For a combustion turbine that uses exhaust temperature and not the actual output in megawatts to control the operation of the turbine (or for a group of identical units of this type), the owner or operator must document that the unit (or each unit in the group) has operated within ± 10% of the set point temperature for 85.0% of the operating hours in the previous 12 calendar quarters to qualify for single-load testing. Alternatively, for sources that report emissions data only during the ozone season, the historical set point temperature analysis may be based on unit operation in the previous three ozone seasons, rather than unit operation in the previous 12 calendar quarters. When the set point temperature is used rather than unit load to justify single-load testing, the designated representative shall certify in the monitoring plan for the unit that this is the normal manner of unit operation and shall document the setpoint temperature.

* * * * *

(3) *Heat input.* * * *

(i) *Maximum rated hourly heat input method.* * * *

(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, for compliance purposes, 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 heat input values for May, June and the third calendar quarter of the year.

(ii) *Long term fuel flow heat input method.* * * *

(C) Except as provided in paragraph (c)(3)(ii)(C)(*3*) of this section, for each fuel combusted during a quarter, the gross calorific value of the fuel shall be determined by either:

(*1*) Using the applicable procedures for gas and oil analysis in sections 2.2 and 2.3 of appendix D to this part. If this option is chosen the highest gross calorific value recorded during the previous calendar year shall be used (or, for a new or newly-affected unit, if there are no sample results from the previous year, use the highest GCV from the samples taken in the current year); or

(*2*) Using the appropriate default gross calorific value listed in Table LM–5 of this section.

(*3*) For gaseous fuels other than pipeline natural gas or natural gas, the GCV sampling frequency shall be daily unless the results of a demonstration under section 2.3.5 of appendix D to this part show that the fuel has a low GCV variability and qualifies for monthly sampling. If daily GCV sampling is required, use the highest GCV obtained in the calendar quarter as GCV_{max} in Equation LM–3, of this section.

(D) If Eq. LM–2 is used for heat input determination, the specific gravity of each type of fuel oil combusted during the quarter shall be determined either by:

(*1*) Using the procedures in section 2.2.6 of appendix D to this part. If this option is chosen, use the highest specific gravity value recorded during the previous calendar year (or, for a new or newly-affected unit, if there are no sample results from the previous year, use the highest specific gravity from the samples taken in the current year); or

* * * * *

(E) The quarterly heat input from each type of fuel combusted during the quarter by a low mass emissions unit or group of low mass emissions units sharing a common fuel supply shall be determined using either Equation LM–2 or Equation LM–3 for oil (as applicable to the method used to quantify oil usage) and Equation LM–3 for gaseous fuels. 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.

$$HI_{fuel\text{-}qtr} = M_{qtr} \frac{GCV_{max}}{10^6} \qquad \text{Eq. LM-2 (for fuel oil)}$$

Where:

$HI_{fuel\text{-}qtr}$ = Quarterly total heat input from oil (mmBtu).

M_{qtr} = Mass of oil consumed during the quarter, determined as the product of the volume of oil under paragraph (c)(3)(ii)(B) of this section and the specific gravity under paragraph (c)(3)(ii)(D) of this section (lb).

GCV_{max} = Gross calorific value of oil, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/lb)

10^6 = Conversion of Btu to mmBtu.

$$HI_{fuel\text{-}qtr} = Q_{qtr} \frac{GCV_{max}}{10^6} \qquad \text{Eq. LM-3 (for gaseous fuel or fuel oil)}$$

Where:

$HI_{fuel\text{-}qtr}$ = Quarterly heat input from gaseous fuel or fuel oil (mmBtu).

Q_{qtr} = Volume of gaseous fuel or fuel oil combusted during the quarter, as determined under paragraph (c)(3)(ii)(B) of this section standard cubic feet (scf) or (gal), as applicable.

GCV_{max} = Gross calorific value of the gaseous fuel or fuel oil combusted during the quarter, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/scf) or (Btu/gal), as applicable.

10^6 = Conversion of Btu to mmBtu.

(F) Use Eq. LM–4 to calculate $HI_{qtr\text{-}total}$, the quarterly heat input (mmBtu) for all fuels. $HI_{qtr\text{-}total}$, shall be the sum of the $HI_{fuel\text{-}qtr}$ values determined using Equations LM–2 and LM–3.

$$HI_{qtr\text{-}total} = \sum_{\text{all-fuels}} HI_{fuel\text{-}qtr} \qquad \text{(Eq. LM-4)}$$

(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 emissions unit or each low mass emissions 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 Equations LM–5 or LM–6. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly cumulative load for the second calendar quarter of the year shall include only the unit loads for the months of May and June.

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

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

Where:

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

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) * * *

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).

$\Sigma^{MWqtr}_{all-units}$ = Sum of the quarterly operating loads (from Eq. LM–5) for all units in the group (MW).

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

(4) *Calculation of SO_2, NO_X and CO_2 mass emissions.* * * *

(i) *SO_2 mass emissions.*

(A) * * *

Where: * * *

EF_{SO2} = Either the SO_2 emission factor from Table LM–1 of this section or the fuel-and-unit-specific SO_2 emission rate from paragraph (c)(1)(i) of this section (lb/mmBtu).

* * * * *

(ii) *NO_X mass emissions.*

* * * * *

(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, and the second quarter report shall include emissions data only for May and June.

(iii) *CO_2 Mass Emissions.*

(A) * * *

Where: * * *

EF_{CO2} = Either the fuel-based CO_2 emission factor from Table LM–3 of this section or the fuel-and-unit-specific CO_2 emission rate from paragraph (c)(1)(iii) of this section (tons /mmBtu). * * *

* * * * *

(e) * * *

(2) For low mass emissions units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use one of the methods specified in paragraph (c)(3)(ii)(B)(*2*) of this section to determine fuel usage, the owner or operator shall keep, at the facility, a copy of the standard used and shall keep records, for three years, of all measurements obtained for each quarter using the methodology.

* * * * *

(6) For unmanned facilities, the records required by paragraphs (e)(1), (e)(2) and (e)(4) of this section may be kept at a central location, rather than at the facility.

* * * * *

15. Section 75.20 is amended by:

a. Revising paragraphs (b)(3)(i), (c)(2)(ii), (c)(2)(iii), (c)(4) introductory text, (c)(4)(i) through (iii), (g)(2), (h)(1), (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 paragraph (a)(3) by revising in the first sentence the words ''section for each continuous emission or opacity monitoring system or component thereof,'' to read ''section, each'', by removing the words ''or component thereof'' in each of the two remaining occurrences of these words, and by 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 paragraph (b)(2) by removing the word ''not'' before the words ''required for certification'';

h. In paragraph (b)(5) by revising the third and fourth sentences;

i. In paragraph (c) introductory text by adding in the third sentence the word ''otherwise'' before the word ''specified,'' and the words ''and in sections 6.3.1 and 6.3.2 of appendix A to this part,'' after the words ''(b)(1), (d), & (e) of this section,'';

j. Removing the second paragraph designated (c)(1)(v) and paragraph (h)(4)(iii);

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

l. In paragraph (d)(2)(iii) by removing the words ''or SO_2-diluent'' in the third sentence, by revising the last sentence, and by adding two new sentences at the end of the paragraph;

m. 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;

n. In the third sentence of (d)(2)(vii) by revising the words ''analyzer and specify'' to read ''analyzer, beginning with the letters ''LK'' (*e.g.,* ''LK1,'' ''LK2,'' etc.) and shall specify'';

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

p. In paragraph (g)(5) by adding the words ''(or recertified)'' after both occurrences of the words ''provisionally certified'', by 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, and by removing the word ''either'' from the second sentence; and

q. In paragraph (h)(2) by revising the reference to ''§ 75.63(a)(1)(iii)'' to read ''§ 75.63(a)(1)(ii)''.

The revisions and additions read as follows:

§ 75.20 Initial certification and recertification procedures.

* * * * *

(b) * * *

(3) * * *

(i) The owner or operator shall 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 either: the hour of successful completion of all of the required recertification tests; or the hour in which a probationary calibration error test (according to paragraph (b)(3)(ii) of this section) is performed and passed, following all necessary repairs, adjustments or reprogramming of the monitoring system. 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. Notwithstanding these requirements, 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.

* * * * *

(5) * * * 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) *Initial certification and recertification procedures.*

* * * * *

(2) * * *

(ii) Relative accuracy test audits, as follows:

(A) A single-load (or single-level) RATA at the normal load (or level), as defined in section 6.5.2.1(d) of appendix A to this part, for a flow monitor installed on a peaking unit or bypass stack, or for a flow monitor exempted from multiple-level RATA testing under section 6.5.2(e) of appendix A to this part;

(B) For all other flow monitors, a RATA at each of the three load levels (or operating 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 (or single-level) 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

* * * * *

(d) * * *

(2) * * *

(iii) * * * However, if the linearity test is performed within 168 unit or stack operating hours but is either failed or aborted due to a problem with the CEMS or like-kind replacement analyzer, then all of the conditionally valid data are invalidated back to the hour of the probationary calibration error test, and data from the non-redundant backup CEMS or from the primary monitoring system of which the like-kind replacement analyzer is a part remain invalid until the hour of completion of a successful linearity test. Notwithstanding this requirement, the conditionally valid data status may be re-established after a failed or aborted linearity check, if corrective action is taken and a calibration error test is subsequently passed. However, in no case shall the use of conditional data validation extend for more than 168 unit or stack operating hours beyond the date and time of the original probationary calibration error test when the analyzer was brought into service.

* * * * *

(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 quality-assurance testing, 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) * * *

(1) *Monitoring plan.* The designated representative shall submit a monitoring plan in accordance with §§ 75.53 and 75.62.

* * * * *

(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 on the date of submittal (consistent with the definition of ''submit'' in § 72.2 of this chapter) of a complete certification application, 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)(2)(i).

(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)(i), 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), on an annual or ozone season basis, as applicable.

§ 75.21 [Amended].

16. Section 75.21 is amended by:

a. In paragraph (a)(7) by adding the words ''only for infrequent, non-routine operations (e.g.,'' after the words ''higher sulfur fuel(s)'' in the first sentence, and by adding a closing parenthesis after the words ''short-term testing'' in the first sentence;

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

d. In paragraph (e)(2) by revising the word ''another'' to read ''other''.

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 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 revising the period at the end of the paragraph to read ''; 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 paragraph (c) heading introductory text, and paragraph (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, (d), 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 and paragraph (a)(2) (except for Equation 9);

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. In paragraph (a)(3) by revising the first three sentences.

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 begin calculating the percent monitor data availability as described in paragraph (a)(1) of this section, and shall, upon completion of the first 720 quality-assured monitor operating hours, record, by means of the automated data acquisition and handling system, the percent monitor data availability for each monitored parameter. 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 begin calculating the percent monitor data availability as described in paragraph (a)(1) of this section, and shall, upon completion of the first 2,160 quality-assured monitor operating hours, record, by means of the automated data acquisition and handling system, the percent monitor data availability for each monitored parameter. 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 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.

* * * * *

(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 operating hours in the previous three years (26,280 clock hours), replace the words ''during previous 8,760 unit operating hours'' in the numerator of Equation 9 with ''in the previous three years'' and replace ''8,760'' in the denominator of Equation 9 with ''total unit operating hours in the previous three years.'' * * *

* * * * *

22. Section 75.33 is amended by:

a. Revising paragraph (a), removing Tables 1 and 2 after paragraph (a), and revising paragraph (c) introductory text;

b. Adding paragraphs (b)(5), (b)(6), (b)(7), (c)(7), (c)(8), (c)(9), (d), and (e), including new Tables 3 and 4;

c. In paragraph (c)(1) introductory text and paragraph (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

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

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). The owner or operator may either implement the provisions of paragraphs (b) and (c) of this section on a non-fuel-specific basis, or may, as described in paragraphs (b)(5), (b)(6), (c)(7) and (c)(8) of this section, provide fuel-specific substitute data values. 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) For units that combust more than one type of fuel, the owner or operator may opt 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.

(6) Use the following guidelines to implement paragraphs (b)(1) through (b)(4) of this section on a fuel-specific basis:

(i) Separate the historical, quality-assured SO_2 concentration data according to the type of fuel combusted;

(ii) For units that co-fire different types of fuel, either group the co-fired hours with the historical data for the fuel with the highest SO_2 emission rate (e.g., if diesel oil and pipeline natural gas are co-fired, count co-fired hours as oil-burning hours), or separate the co-fired hours from the single-fuel hours;

(iii) For the purposes of providing substitute data under paragraph (b)(4) of this section, determine a separate, fuel-specific maximum potential SO_2 concentration (MPC) value for each type of fuel 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. For co-firing, the MPC value shall be based on the fuel with the highest SO_2 emission rate. The exact methodology used to determine each fuel-specific MPC value shall be documented in the monitoring plan for the unit or stack; and

(iv) For missing data periods that require 720-hour (or, if applicable, 3-year) lookbacks, use historical data for the type of fuel combusted during each hour of the missing data period to determine the appropriate substitute data value for that hour. For co-fired missing data hours, if the historical data are separated into single-fuel and co-fired hours, use co-fired data to provide the substitute data values. Otherwise, use data for the fuel with the highest SO_2 emission rate to provide substitute data values for co-fired missing data hours.

(7) Table 1 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 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, (c)(5), does not apply to non-load-based, affected units using operational bins. * * *

* * * * *

(7) This paragraph (c)(7) does not apply to affected units using non-load-based operational bins. For units that combust more than one type of fuel, the owner or operator may opt to implement the missing data routines in paragraphs (c)(1) through (c)(6) 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

(8) This paragraph, (c)(8), does not apply to affected units using non-load-based operational bins. Use the following guidelines to implement paragraphs (c)(1) through (c)(6) of this section on a fuel-specific basis:

(i) Separate the historical, quality-assured NO_X emission rate, NO_X concentration, or flow rate data according to the type of fuel combusted;

(ii) For units that co-fire different types of fuel, either group the co-fired hours with the historical data for the fuel with the highest NO_X emission rate, NO_X concentration or flow rate, or separate the co-fired hours from the single-fuel hours;

(iii) For the purposes of providing substitute data under paragraph (c)(4) of this section, a separate, fuel-specific maximum potential concentration (MPC), maximum potential NO_X emission rate (MER), or maximum potential flow rate (MPF) value (as applicable) shall be determined for each type of fuel combusted in the unit, in a manner consistent with § 72.2 of this chapter and with section 2.1.2.1 or 2.1.4.1 of appendix A to this part. For co-firing, the MPC, MER or MPF value shall be based on the fuel with the highest emission rate or flow rate (as applicable). The exact methodology used to determine each fuel-specific MPC, MER or MPF value shall be documented in the monitoring plan for the unit or stack.

(iv) For missing data periods that require 2,160-hour (or, if applicable, 3-year) lookbacks, use historical data for the type of fuel combusted during each hour of the missing data period to determine the appropriate substitute data value for that hour. For co-fired missing data hours, if the historical data are separated into single-fuel and co-fired hours, use co-fired data to provide the substitute data values. Otherwise, use data for the fuel with the highest NO_X emission rate, NO_X concentration or flow rate (as applicable) to provide substitute data values for co-fired missing data hours. 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	$N \le 24$	Average	HB/HA.
	$N > 24$	For SO_2, CO_2, and H_2O**, the greater of:.	
		Average	HB/HA.
		90th percentile	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	$N \le 8$	Average	HB/HA.
	$N > 8$	For SO_2, CO_2, and H_2O**, the greater of:.	
		Average	HB/HA.
		95th percentile	720 hours*.
		For O_2 and H_2O^x, the lesser of:.	
		Average	HB/HA.
		5th percentile	720 hours*.
80 or more, but below 90	$N > 0$	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 or % (for SO_2, CO_2, and H_2O**) *or*.	
		Minimum potential concentration or % (for O_2 and H_2Ox).	None.

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

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

[1] Where a unit with add-on SO_2 emission controls can demonstrate that the controls are operating properly, as provided in § 75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 720 operating hours.

[2] During unit operating hours.

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

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

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

Trigger conditions		Calculation routines		
Monitor data availability (percent)	Duration (N) of CEMS outage (hours)[2]	Method	Lookback period	Load ranges
95 or more	$N \le 24$	Average	2160 hours*	Yes.
	$N > 24$	The greater of:.		
		Average	HB/HA	No.
		90th percentile	2160. hours*	Yes.
90 or more, but below 95	$N \le 8$	Average	2160 hours*	Yes.
	N>8	The greater of.		
		Average	HB/HA	No
		95th percentile	2160 hours*	Yes.
80 or more, but below 90	$N > 0$	Maximum value[1]	2160 hours*	Yes.
Below 80	$N > 0$	Maximum NO_X emission rate; or maximum potential NO_X NO_X concentration; or maximum potential flow rate.	None	No.

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

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

[1] Where a unit with add-on NO_X emission controls can demonstrate that the controls are operating properly, as provided in § 75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 720 operating hours. Alternatively, units with add-on controls that report NO_X mass emissions on a year-round basis under subpart H of this part may use separate ozone season and non-ozone season databases to provide substitute data values, as described in § 75.34(a)(2).

[2] During unit operating hours.

(9) The load-based provisions of paragraphs (c)(1) through (c)(8) 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), and (c)(6) 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, for each missing hour, 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).

(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, for each missing hour, 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).

(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 § 72.2 of this chapter, 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, as defined in § 72.2 of this chapter, or the maximum potential NO_X concentration, as defined in section 2.1.2.1 of appendix A to this part.

(6) Table 3 of this section summarizes the provisions of paragraphs (d)(1) through (d)(5) 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 unit that does not produce electrical or thermal output, 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, 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), and (c)(8) are not applicable; and

(iv) In paragraph (c)(6), the words, ''for either the corresponding load range (or a higher load range) or at 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
95 or more	$N \le 24$	Average	2160 hours*
	$N > 24$	90th percentile	2160 hours*
90 or more, but below 95	$N \le 8$	Average	2160 hours*
	$N > 8$	95th percentile	2160 hours*

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

Trigger conditions		Calculation routines	
Monitor data availability (percent)	Duration (N) of CEMS outage (hours)[1]	Method	Lookback period
80 or more, but below 90	N > 0	Maximum value	2160 hours*
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, and data at the corresponding operational bin are used to provide substitute data values. If operational bins are not used, the lookback period is the previous 2,160 quality-assured monitor operating hours. For units that report data only for the ozone season, include only quality-assured monitor operating hours within the ozone season in the lookback period. Use data from no earlier than three years prior to the missing data period.

[1]During unit operation.

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
95 or more	$N \leq 24$	Average	2160 hours*
	N > 24	The greater of:	
		Average	HB/HA
		90th percentile	2160 hours*
90 or more, but below 95	$N \leq 8$	Average	2160 hours*
	N > 8	The greater of:	
		Average	HB/HA
		95th percentile	2160 hours*
80 or more, but below 90	N > 0	Maximum value	2160 hours*
Below 80, or operational bin indeterminable.	N > 0	Maximum potential flow rate	None

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

[1] During unit operation.

23. Section 75.34 is amended by:

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

b. Redesignating paragraphs (a)(2) and (a)(3) as paragraphs (a)(3) and (a)(4), respectively;

c. Adding a new paragraph (a)(2);

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

e. 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 shall use one of the options in paragraphs (a)(1), (a)(2) or (a)(4) of this section for each hour in which quality-assured data from the outlet SO_2 and/or NO_X monitoring system(s) are not obtained, and shall document which option is selected in the monitoring plan required under § 75.53. If the option in paragraph (a)(1) or (a)(2) is selected, the owner or operator may also use the petition provision in paragraph (a)(3) of this section.

(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) This paragraph, (a)(2), applies only to a unit which, as provided in § 75.74(a) or § 75.74(b)(1), reports NO_X mass emissions on a year-round basis under a state or Federal NO_X mass emissions reduction program that adopts the emissions monitoring provisions of this part. If the add-on NO_X emission controls installed on such a unit are operated only during the ozone season or are operated in a more efficient manner during the ozone season than outside the ozone season, the owner or operator may implement the missing data provisions of paragraph (a)(1) of this section in the following alternative manner:

(i) The historical, quality-assured NO_X emission rate or NO_X concentration data may be separated into two categories, i.e., data recorded inside the ozone season and data recorded outside the ozone season;

(ii) For the purposes of the missing data lookback periods described under §§ 75.33(c)(1), (c)(2) and (c)(3), the substitute data values shall be taken from the appropriate database, depending on the date(s) and hour(s) of the missing data period. That is, if the missing data period occurs inside the ozone season, the ozone season data shall be used to provide substitute data. If the missing data period occurs outside the ozone season, data from outside the ozone season shall be used to provide substitute data.

(iii) A missing data period that begins outside the ozone season and continues into the ozone season shall be considered to be two separate missing data periods, one ending on April 30, hour 23, and the other beginning on May 1, hour 00;

(iv) For missing data hours outside the ozone season, the procedures of § 75.33 may be applied unconditionally, i.e, documentation of the operational status of the emission controls is not required in order to apply the standard missing data routines.

* * * * *

(d) In order to implement the options in paragraphs (a)(1) and (a)(3) of this section, the owner or operator shall keep records of information as described in § 75.58(b)(3) to verify the proper operation of all add-on SO_2 or NO_X emission controls, during all periods of SO_2 or NO_X emission missing data. If the owner or operator elects to implement the missing data option in paragraph (a)(2) of this section, the records in § 75.58(b)(3) are required to be kept only for the ozone season. 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. 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 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 or substitute CO_2 data for heat input determination, as applicable, 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 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, by removing the words ‘‘On and after April 1, 2000'' in the third sentence and capitalizing ‘‘When'' to begin that sentence, and by removing the final 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).

(c) [Reserved]

* * * * *

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'' 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:

a. In paragraph (b)(2)(v)(B) by adding the words ''(Eq. 22)'' immediately before ''where''; and

b. By revising Equation 27 in paragraph (c)(2)(ii).

The revisions and additions read as follows:

§ 75.41 Precision criteria.

* * * * *

(c) * * *

(2) * * *

(ii) * * *

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

* * * * *

28. Section 75.53 is amended by:

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

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

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) introductory text by adding the words ''(or equivalent facility ID number assigned by EPA, if the facility does not have an ORISPL number)'' after the words ''Data Base'';

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

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

g. In paragraph (e)(1)(ix) by revising the words ''Part 75 monitoring'' to read ''Monitoring'' and by revising the words ''reporting year, and 767 reporting indicator'' to read ''ARP/Subpart H facility ID number or ORISPL number (as applicable), reporting year, and 767 reporting indicator (or equivalent)'';

h. In paragraph (e)(1)(xii) introductory text by revising the words ''For each unit or common stack (except for peaking units)'' to read ''Unless otherwise specified in section 6.5.2.1 of appendix A to this part, for each unit or common stack'';

i. In paragraph (e)(1)(xii)(A) and (B) by adding the words '', or ft/sec (as applicable)'' to the end of each paragraph, and by adding a comma after ''megawatts'' in each paragraph;

j. In paragraph (e)(1)(xii)(D) by revising the first occurrence of the word ''load'' to read ''data'' and by adding the words ''(or operating)'' after each other occurrence of the word ''load'' and in paragraphs (e)(1)(xii)(B), (C), and (E) by adding the words ''or operating'' after each occurence of the word ''load'';

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

l. In paragraph (f)(2)(i)(H) by adding the words ''or ozone season'' after the word ''year'' and by revising the word ''part'' to read ''chapter'';

m. In paragraph (f)(5) introductory text by adding the words ''that accompanies the initial certification application'' to the end of the paragraph;

n. In paragraph (f)(5)(i) by revising the second sentence and by adding a third sentence and new paragraphs (f)(5)(i)(A) through (F);

o. In paragraph (f)(5)(ii)(C) by revising the words ''natural gas or'' to read ''gaseous fuel(s) and/or'' in two occurrences: and

p. In paragraph (f)(5)(ii)(E) by adding the words '', estimated'' after the word ''actual''.

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.

(c) [Reserved]

(d) [Reserved]

(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 for daily or annual fuel sampling for sulfur content, as applicable.

* * * * *

(5) * * *

(i) * * * This report will include either the previous three years actual or projected emissions. The following items should be included:

(A) Current calendar year of application;

(B) Type of qualification;

(C) Years one, two, and three;

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

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

(F) 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)(iv);

e. Amending paragraph (d)(6) and (d)(7) by removing the words ''either'', ''hundredth or'', and ''prior to April 1, 2000 and rounded to the nearest thousandth on and after April 1, 2000''.

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 SO_2 and/or NO_X emission controls: SO_2 concentration or NO_X emission rate estimate from Agency preapproved parametric monitoring method.
6	Average of the hourly SO_2 concentrations, CO_2 concentrations, O_2 concentrations, NO_X concentrations, flow rates, moisture percentages or NO_X emission rates for the hour before and the hour following a missing data period.
7	Initial missing data procedures used. Either: (a) the average of the hourly SO_2 concentration, CO_2 concentration, O_2 concentration, or moisture percentage for the hour before and the hour following a missing data period; or (b) the arithmetic average of all NO_X concentration, NO_X emission rate, or flow rate values at the corresponding load range (or a higher load range), or at the corresponding operational bin (non-load-based units, only); or (c) the arithmetic average of all previous NO_X concentration, NO_X emission rate, or flow rate values (non-load- based units, only).
8	90th percentile hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or 10th percentile hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
9	95th percentile hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or 5th percentile hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
10	Maximum hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or minimum hourly O_2 concentration or moisture percentage in the applicable lookback period (moisture missing data algorithm depends on which equations are used for emissions and heat input).
11	Average of hourly flow rates, NO_X concentrations or NO_X emission rates in corresponding load range, for the applicable lookback period. For non-load-based units, report either the average flow rate, NO_X concentration or NO_X emission rate in the applicable lookback period, or the average flow rate or NO_X value at the corresponding operational bin (if operational bins are used).
12	Maximum potential concentration of SO_2, maximum potential concentration of CO_2, maximum potential concentration of NO_X maximum potential flow rate, maximum potential NO_X emission rate, maximum potential moisture percentage, minimum potential O_2 concentration or minimum potential moisture percentage, as determined using § 72.2 of this chapter and section 2.1 of appendix A to this part (moisture missing data algorithm depends on which equations are used for emissions and heat input).
13	[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, CO_2 concentration, NO_X emission rate or flow rate, *or* minimum potential O_2 concentration or moisture percentage, for an hour in which flue gases are discharged through an unmonitored bypass stack.
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.

* * * * *

33. Section 75.58 is amended by:

a. Revising the introductory paragraph;

b. In paragraphs (b)(1)(i) and (c) introductory text 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) introductory text;

e. In paragraph (b)(3)(i) by adding the words '', for each hour of missing SO_2 or NO_X emission data,'' after the word ''demonstrate'';

f. In paragraph (b)(3)(ii) by adding the words '', for each hour of missing SO_2 or NO_X emission data,'' after the word ''indicating'';

g. In paragraphs (b)(3)(iii) and (b)(3)(iv) by revising the reference to ''§ 75.34(a)(2)'' to read ''§ 75.34(a)(3)'';

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

i. In paragraph (d) introductory text by removing the words ''paragraph § 75.54(d) or'';

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

k. In paragraph (f) introductory text by removing the words ''§§ 75.54(b) through (e) or''; and

l. In paragraph (f)(1)(iii) by adding the words ''other gaseous fuel,'' after the words ''natural gas,''.

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

* * * * *

34. Section 75.59 is amended by:

a. Revising the introductory paragraph;

b. In paragraph (a)(1)(vii), by revising ''Calibration'' to read ''Reference signal or calibration'';

c. In paragraph (a)(5)(ii)(E) by removing both occurrences of the word ''load'' and by adding the word ''operating'' before the word ''levels'';

d. In paragraph (a)(5)(ii)(F) by adding the words ''(or operating level)'' before the word ''indicator'';

e. In paragraph (a)(5)(ii)(L) by adding the words '', except for units that do not produce electrical or thermal output'' after the words ''lb/hr)'';

f. In paragraph (a)(5)(iii)(E) by adding the words ''(or operating)'' before both of the two occurrences of the word ''level'' and by adding the words '', or as otherwise specified by the Administrator, for units that do not produce electrical or thermal output'' after the words ''lb/hr'';

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

h. In paragraph (a)(7)(ii)(A) by removing the word ''load'';

i. Revising paragraphs (a)(7)(ii)(P) and (a)(7)(iii)(F);

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

k. In paragraph (a)(12)(v) introductory text by adding the words ''(or single-level)'' before the word ''flow'';

l. In paragraphs (a)(12)(v)(C) and (E) by adding the words ''(or operating)'' before the word ''level'', and by, in paragraph (C), removing the period at the end of the paragraph and adding a semicolon in its place;

m. In paragraph (a)(12)(v)(D) by adding the words ''(or operating level)'' before the word ''data'';

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

o. In paragraph (b)(4)(ii)(K) by removing the word ''and'' after the semicolon;

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

q. Adding paragraph (b)(4)(ii)(M);

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

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

t. In paragraph (d)(1)(xi) by adding the word ''and'' after the semicolon and in paragraph (d)(1)(xii) by removing the semicolon and adding a period in its place;

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

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

w. In newly designated paragraph (d)(3)(x) by revising the words ''§§ 75.19(c)(1)(iv)(B)(*1*) and (*3*)'' to read ''§ 75.19(c)(1)(iv)(B)(*1*)''.

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) * * *

(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.

* * * * *

(d) * * *

(2) For each single-load or multiple-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:

a. In paragraph (b)(6), adding the words ''in writing (or by electronic mail)'' after the words ''If requested''; and

b. Adding paragraph (b)(7).

The revisions and additions read as follows:

§ 75.60 General provisions.

* * * * *

(b) * * *

(7) *Routine appendix E retest reports.* If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report 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) introductory text by removing the words ''and except for testing only of the data acquisition and handling system'' from 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 heading and first sentence, and by adding a new sentence after the first sentence;

c. In paragraph (a)(1)(ii) by revising the word ''and'' to read '', and partial'' in the heading, and, in the first sentence, by adding the word ''required'' after the word ''retesting'', and revising the words ''recertification under § 75.20(b), notice of testing'' to read ''partial recertification testing required under § 75.20(b)(2), notice of the date of any required RATA testing or any required retesting under section 2.3 in appendix E to this part'';

d. In paragraph (a)(1)(iii) by adding the words ''or recertification'' after each occurrence of the word ''certification'' and by adding the words ''must be aborted, or'' after the words ''was failed or'';

e. 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;

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

g. In paragraph (a)(2)(i) by adding the words ''or becomes affected'' after the words ''commences commercial operation'';

h. In paragraph (a)(2)(ii) by adding the words ''or becomes affected,'' after both occurrences of the words ''commences commercial operation'' and by removing the comma between the words ''or'' and ''the date'';

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

j. Revising the heading and the first sentence of paragraph (a)(5) introductory text;

k. In paragraph (a)(5)(ii) by adding the words '', appendix E retest, or low mass emissions unit retest'' before the word ''immediately''; and

l. 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.

(i) Notification of initial certification testing and full recertification. Initial certification test notifications and notifications of full recertification testing under § 75.20(b)(2) shall be submitted not later than 21 days prior to the first scheduled day of certification or recertification testing. In emergency situations when full recertification testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled.

* * * * *

(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 or'' before both occurrences of the word ''recertification''.

The revisions and additions read as follows:

§ 75.62 Monitoring plan submittals.

(a) * * *

(1) *Electronic.* Using the format specified in paragraph (c) of this section, the designated representative for an affected unit shall submit a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (a)(2) of this section) to the Administrator as follows: no later than 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.

* * * * *

38. Section 75.63 is amended by:

a. In the section heading by removing the word ''submittals'';

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

c. In paragraph (a)(2) heading by adding the words ''and diagnostic testing'';

d. 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)'';

e. In paragraph (a)(2)(ii) by adding, in the first sentence, the words ''under § 75.20(b)'' after the word ''tests'' and the words ''of this section'' after the words ''paragraph (b)(2)'', and by revising, in the second sentence, the words ''for submission to it of a hardcopy recertification'' to read ''to provide hardcopy recertification test data and results'';

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

g. In paragraph (b)(1)(i), by removing the words ''§§ 75.53(c) and (d), or § '' and ''as applicable,'';

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

i. In the first sentence of paragraph (b)(2)(i), by removing the words ''§§ 75.53(c) and (d), or § '' and ''as applicable,''.

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). 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 § 75.53(f)(5)(i) and paragraph (b)(1)(i) of this section, and a hardcopy cover letter identifying the submittal as a low mass emissions unit certification application; 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) and § 75.53(f)(5)(ii), 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.

* * * * *

39. Section 75.64 is amended by:

a. In paragraph (a) introductory text by revising the first sentence, and by adding in the third sentence the words ''or has been placed in long-term cold storage'' after the words ''§ 75.4(a)'';

b. In paragraph (a)(2) introductory text by revising the words ''§§ 75.53 through 75.59'' to read § 75.53 and §§ 75.57 through 75.59'';

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

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

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

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

g. In paragraph (a)(2)(viii) by adding a comma after the word ''coefficients'' and by removing the words ''§ 75.56(a)(5)(vii), § 75.56(a)(5)(ix),'';

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

i. 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'';

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

k. In paragraph (d) by revising the words ''electronic or hardcopy'' to read ''(unless otherwise approved by the Administrator) electronic''; and

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

The revisions and additions read as follows:

§ 75.64 Quarterly reports.

(a) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in paragraphs (a), (b), and (c) of this section to the Administrator quarterly, beginning with the data from the earlier of the calendar quarter corresponding to the date of provisional certification; or the calendar quarter corresponding to the relevant deadline for initial certification in § 75.4(a), (b), or (c). * * *

* * * * *

§ 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,'';

b. In paragraph (f) introductory text by revising the reference to ''§ 75.34(a)(2)'' to ''§ 75.34(a)(3)''; and

c. 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 paragraph (e);

d. In paragraph (f) introductory text by revising the reference to ''§ 75.74'' to read ''§ 75.74(c)(7)'';

e. In paragraph (f)(1) introductory text by revising the words ''missing data procedures in subpart D of this part'' to read ''applicable missing data procedures in §§ 75.31 through 75.37'';

f. 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'';

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

h. In paragraph (f)(1)(iii) by adding the word ''rate'' after the first occurrence of the word ''input'', revising the word ''mmBtu'' to read ''mmBtu/hr'', and by removing the words ''or by an accepted monitoring system under appendix D to this part'';

i. 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;

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

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

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

m. 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) * * *

(1) * * *

(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 removing the hyphens after the words ''O_2'' and ''CO_2'' and by revising the words ''heat input, or, if applicable, use the procedures in appendix D to this part'' to read ''heat input rate'';

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''; and

e. In paragraph (c)(2) by adding the word ''rate'' to the end of the first sentence and by revising the second sentence; and

f. In paragraph (d)(2) by revising the second sentence, by revising the words ''paragraph (c) of this section or, if applicable, paragraph (e)'' to read ''paragraph (c)(1) or (c)(2)'' in the third sentence, and by adding a new sentence at the end of the paragraph.

The revisions and additions read as follows:

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

* * * * *

(c) * * *

(2) * * * However, for a common pipe configuration, the heat input rate apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart, unless all of the units served by the common pipe are affected units and have similar efficiencies; or

* * * * *

(d) * * *

(2) * * * However, for a common pipe configuration, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart unless all of the units served by the common pipe are affected units and have similar efficiencies. * * * 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.

* * * * *

44. Section 75.72 is amended by:

a. In the introductory paragraph to the section by revising the words ''(in mmBtu/hr) and the hourly operating time (in hr)'' to read ''rate (in mmBtu/hr) and the unit or stack operating time (as defined in § 72.2)'';

b. Revising paragraph (a)(1) introductory text and paragraph (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'';

e. By adding the words ''and a diluent monitor'' after the word ''system'' in the newly redesignated paragraph (a)(1)(iii)(B);

f. In paragraph (a)(2) introductory text by adding the words '', for purposes of heat input determination,'' after the words ''from each unit and'';

g. In paragraph (a)(2)(ii)(A) by adding the word ''rate'' after the words ''heat input'';

h. In paragraph (b)(1) introductory text by removing the semicolon and by adding the words '', for purposes of heat input determination,'' at the end of the paragraph;

i. Revising paragraph (b)(1)(ii)(A);

j. In paragraph (b)(2)(ii)(B) by adding the word ''rate'' after the words ''heat input'' in the first sentence and by revising the second sentence;

k. In paragraph (b)(2)(iii) by adding the words '', in accordance with paragraph (a) of this section'' after the word ''purposes'';

l. Revising paragraph (c);

m. Revising paragraph (d);

n. In paragraph (e) introductory text by revising the first sentence, revising the words ''appendix F of'' to read ''appendix F to'' in the second sentence, and adding a new sentence between the first and second sentences;

o. In paragraph (e)(1) introductory text by revising the second sentence and adding a new third sentence;

p. 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)'';

q. In paragraph (e)(2) by adding the word ''rate'' after the words ''heat input'' in the first sentence and by removing the words ''or a common stack'' in the last sentence; and

r. 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.

* * * * *

(a) * * *

(1) Install, certify, operate, and maintain a NO_X-diluent continuous emissions monitoring system and a flow monitoring system in the common stack, record the combined NO_X mass emissions for the units exhausting to the common stack, and, for 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); or

(ii) Install, certify, operate, and maintain a flow monitoring system and diluent monitor in the duct to the common stack from each unit; or

* * * * *

(b) * * *

(1) * * *

(ii) * * *

(A) Use the procedures in appendix D to determine heat input for that unit; however, for a common pipe configuration, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart unless all of the units served by the common pipe are affected units and have similar efficiencies; and

* * * * *

(2) * * *

(ii) * * *

(B) * * * However, for a common pipe serving both affected and non-affected units, the heat input rate apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart. * * *

* * * * *

(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 may be specific to the type of fuel combusted in the unit during the bypass (see § 75.33(c)(8)). If the unit heat input is determined using a fuel flowmeter, in accordance with appendix D to this part, report NO_X mass emissions as the product of the maximum potential NO_X emission rate and the actual measured hourly heat input rate.

(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) * * * 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. In paragraph (a)(6) introductory text by removing the word ''following'', by revising the words ''this paragraph'' to read ''§ 75.58(c)'', and by removing the colon at the end of the paragraph and adding a period in its place;

c. Removing paragraphs (a)(6)(i) through (a)(6)(vi) and paragraphs (e)(1)(i) and (e)(1)(ii);

d. Adding new paragraphs (a)(8), (d)(6), (f)(1)(vii), and (f)(1)(viii);

e. Revising the second and third sentences of paragraph (c)(3) and adding a new last sentence;

f. Revising paragraph (e)(1); and

g. 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) * * *

(8) 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 a complete, electronic, up-to-date monitoring plan file for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii), 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.

(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 (if applicable).

* * * * *

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) introductory text;

c. In paragraph (c)(2)(ii)(A), adding the words ''(or operating level(s))'' after the words ''RATA load level(s)'';

d. Revising paragraphs (c)(2)(ii)(C) and (c)(2)(ii)(H)(*1*);

e. In paragraph (c)(3)(iii) by revising the first and second sentences;

f. In paragraph (c)(3)(iv) by adding in the second sentence the word ''the'' 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)(x) by adding the words '', if applicable,'' after the words ''§ 75.20(b)(3) and'';

j. 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;

k. 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).

l. 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;

m. In paragraph (c)(5) by adding the word ''rate'' after the words ''heat input'';

n. Revising paragraphs (c)(6)(v), (c)(7)(ii), and (c)(8)(ii);

o. Adding a new paragraph (c)(7)(iii);

p. Revising paragraph (c)(10); and

q. 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 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 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 unit or stack 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 (c)(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.

* * * * *

(C) For flow rate monitoring systems installed on peaking units or bypass stacks and for flow monitors exempted from multiple-level RATA testing under section 6.5.2(e) of appendix A to this part, a single-load (or single-level) RATA is required. For all other flow rate monitoring systems, a 2-load (or 2-level) RATA is required at the two most frequently-used load or operating levels (as defined under section 6.5.2.1 of appendix A to this part), with the following exceptions. Except for flow monitors exempted from 3-level RATA testing under section 6.5.2(e) of appendix A to this part, a 3-load flow RATA is required at least once every five years and is also required if the flow monitor polynomial coefficients or K factor(s) are changed prior to conducting the flow RATA required under this paragraph.

* * * * *

(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 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 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 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) For each flow monitoring system required by this subpart, except for flow monitors installed on non-load-based units that do not produce electrical or thermal output, flow-to-load ratio tests are required in the second and third calendar quarters, in accordance with section 2.2.5 of appendix B to this part. 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 applicable 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 missing data routines in §§ 75.31 through 75.37; 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) In § 75.32(a), the phrases ''the first 720 quality-assured monitor operating hours within the ozone season'' and ''the first 2,160 quality-assured monitor operating hours within the ozone season'' apply, respectively, instead of the phrases ''the first 720 quality-assured monitor operating hours'' and ''the first 2,160 quality-assured monitor operating hours''.

(D) In § 75.32(a)(1), the phrase ''Following initial certification, prior to completion of 3,672 unit (or stack) operating hours within the ozone season'' applies instead of the phrase ''Prior to completion of 8,760 unit (or stack) operating hours following initial certification''.

(E) In Equation 8, the phrase ''Total unit operating hours within the ozone season'' applies instead of the phrase ''Total unit operating hours''.

(F) In § 75.32(a)(2), the phrase ''3,672 unit (or stack) operating hours within the ozone season'' applies instead of the phrase ''8,760 unit (or stack) operating hours''.

(G) 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''.

(H) 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 or stack 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 years (26,280 clock hours) earlier shall be used in Equation 9. For a unit that has accumulated fewer than 3,672 ozone season operating hours in the previous three years, use the following: in the numerator of Equation 9 use ''Total unit operating hours within the ozone season for which quality-assured data were recorded in the previous three years''; and in the denominator of Equation 9 use ''Total unit operating hours within the ozone season, in the previous three years'.''

(I) In § 75.33(a), the phrases ''the first 720 quality-assured monitor operating hours within the ozone season'' and ''the first 2,160 quality-assured monitor operating hours within the ozone season'' apply, respectively, instead of the phrases ''the first 720 quality-assured monitor operating hours'' and ''the first 2,160 quality-assured monitor operating hours''.

(J) 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 use only quality-assured monitor operating hours of data that were recorded within the ozone season and no more than three years (26,280 clock hours) prior to the date and time of the missing data period.''

(K) 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''.

(L) In § 75.34(a)(3), the phrase ''720 quality-assured monitor operating hours within the ozone season'' applies instead of ''720 quality-assured monitor operating hours''.

(8) * * *

(ii) For units with add-on emission controls, using the missing data options in § 75.34(a)(1) through § 75.34(a)(4), 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).

* * * * *

(10) Units may qualify to use the low mass emissions excepted monitoring methodology in § 75.19 on an ozone season basis. In order to be allowed to use this methodology, a unit may not emit more than 50 tons of NO_X per ozone season, as provided in § 75.19(a)(1)(i)(A)(*3*). If any low mass emissions unit fails to provide a demonstration that its ozone season NO_X mass emissions are less than or equal to 50 tons, then the unit is disqualified from using the methodology. The owner or operator must install and certify any equipment needed to ensure that the unit is monitored using an acceptable methodology by December 31 of the following year.

* * * * *

Appendix A Section 1 [Amended]

47. 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. 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. Amending paragraph (a) of section 2.1.1.1 by adding two new sentences following the third sentence;

d. Transferring 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, and then revising the definition of the variable ''%S'' in Equation A–1b and adding a definition for the variable ''GCV'' after the definition of the variable ''%CO_{2w}'' in Equation A–1b;

e. Amending paragraph (b) of section 2.1.1.1 by adding a new sentence after the first sentence and by adding two new sentences to the end of the paragraph;

f. Adding three sentences to the end of paragraph (a) of section 2.1.1.2;

g. Adding a new second sentence to paragraph (c) of section 2.1.1.2 ;

h. Revising the definition of the variable ''MPC'' in Equation A–2 of paragraph (c) of section 2.1.1.2;

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 new second sentence;

k. Removing the first sentence of paragraph (d) of section 2.1.1.4 and adding three sentences in its place;

l. Adding a new fifth sentence in paragraph (g) of section 2.1.1.4;

m. In the first sentence of section 2.1.1.5, revising the words ''paragraphs (a) and (b)'' to read ''paragraphs (a), (b), and (c)'';

n. Removing the final sentence in paragraph (c) of section 2.1.1.5 and adding a new final sentence;

o. In section 2.1.2, revising the words ''section 2.1.2.1'' to read ''sections 2.1.2.1 through 2.1.2.5 of this appendix'';

p. In paragraph (a) of section 2.1.2.1 by adding a new second sentence, by revising the word ''part'' to read ''section'' in the first sentence of Option 1, by adding two new sentences at the end of Option 1, by adding a new sentence at the end of Option 2, by removing the word ''or'' from Option 3, by removing the period at the end of Option 4 and adding ''; or'' in its place; and by adding a new Option 5;

q. Adding a new final sentence to paragraph (b) of section 2.1.2.1;

r. Adding two new sentences to the end of paragraph (c) of section 2.1.2.1;

s. Revising the first sentence of paragraph (d) of section 2.1.2.1;

t. Revising paragraph (e) and Table 2–2 in section 2.1.2.1;

u. Revising paragraph (a) of section 2.1.2.2;

v. In the third sentence of paragraph (b) of section 2.1.2.2, adding the words ''(if applicable)'' after the words '' NO_X emissions'';

w. In paragraph (c) of section 2.1.2.2 by adding the words ''from the NO_X component of a certified monitoring system,'' after the words ''quality assured data'' in the first sentence, by adding the words ''(for units with add-on NO_X controls or turbines using dry low NO_X technology)'' after the words ''malfunction or'' in the second sentence, by adding the words ''(if applicable)'' after the words ''NO_X emissions'' in the third sentence, and by adding a new second sentence after the first sentence;

x. Revising the fourth sentence of paragraph (a) of section 2.1.2.3;

y. In the first sentence of paragraph (b) of section 2.1.2.3, revising the words ''requires a span'' to read ''requires or allows the use of a span value'';

z. Revising the second sentence of paragraph (b) of section 2.1.2.4 and adding a new sentence after the first sentence;

aa. Removing the first sentence of paragraph (c) of section 2.1.2.4 and adding three sentences in its place;

bb. In paragraph (e) of section 2.1.2.4 by adding the words ''or, for units that use dry low NO_X technology,'' after the word ''SNCR),'';

cc. Adding a new sentence after the fourth sentence in paragraph (f) of section 2.1.2.4;

dd. In the third sentence of section 2.1.2.5, revising the words ''paragraphs (a) and (b)'' to read ''paragraphs (a), (b), and (c)'';

ee. In paragraph (c) of section 2.1.2.5, adding the word ''diagnostic'' before the words ''linearity test'' in the fifth sentence and revising the final sentence;

ff. Adding a sentence to the end of the section 2.1.3;

gg. Adding two new sentences to the beginning of section 2.1.3.3;

hh. Revising the third sentence of section 2.1.4.1;

ii. 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'';

jj. Adding a sentence to the end of section 2.1.6; and

kk. Adding text to reserved 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) * * * If both the fuel sulfur content and the GCV are routinely determined from each fuel sample, the owner or operator may, as an alternative to using the highest individual percent sulfur and lowest individual GCV values in the MPC calculation, pair the sulfur content and GCV values from each sample analysis and calculate the ratio of percent sulfur to GCV (*i.e.*, %S/GCV) for each pair of values. If this option is selected, the MPC shall be calculated using the highest %S/GCV ratio in Equation A–1a or A–1b.

* * * * *

(Eq. A–1b)

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) * * * For the purposes of this section, 2.1.1.1, a ''certified'' CEMS means a CEM system that has met the applicable certification requirements of either: This part, or part 60 of this chapter, or a State CEM program, or the source operating permit. * * * 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.

* * * * *

(c) * * * For the purposes of this section, 2.1.1.2, a ''certified'' CEMS means a CEM system that has met the applicable certification requirements of either: This part, or part 60 of this chapter, or a State CEM program, or the source operating permit.

* * * * *

MPC = Maximum potential concentration (ppm), as determined by Eq. A–1a or A–1b in section 2.1.1.1 of this appendix.

* * * * *

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 SO_2 monitoring system. * * *

* * * * *

(g) * * * However, if the default high range option in paragraph (f) of this section is selected, the full-scale of the low measurement range shall not exceed five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm). * * *

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 NO_X Pollutant Concentration Monitors

* * * * *

2.1.2.1 Maximum Potential Concentration

(a) * * * For the purposes of this section, 2.1.2.1, and section 2.1.2.2 of this appendix, a ''blend'' means a frequently-used fuel mixture having a consistent composition (e.g., an oil and gas mixture where the relative proportions of the two fuels vary by no more than 10%, on average). * * *

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 2: * * * For a new gas-fired or oil-fired combustion turbine, if a default MPC value of 50 ppm was previously selected from Table 2–2, that value may be used until March 31, 2003;

* * * * *

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.

(b) * * * As a second alternative, when the NO_X MPC is determined from emission test results or from historical CEM data, as described in paragraphs (a), (d) and (e) of this section, quality-assured diluent gas (i.e., O_2 or CO_2) data recorded concurrently with the MPC may be used to calculate the MER.

(c) * * * Note that whichever MPC option in paragraph 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 are not in operation or when the DLN controls are not in the premixed (low-NO_X) mode. * * *

(e) If historical CEM data are used to determine the MPC, the data must, for uncontrolled units or units equipped with low-NO_X burner technology and no other NO_X controls, represent a minimum of 720 quality assured monitor operating hours from the NO_X component of a certified monitoring system, obtained under various operating conditions including the minimum safe and stable load, normal load (including periods of high excess air at normal load), and maximum load. For the purposes of this section, 2.1.2.1, a ''certified'' CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. 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 are not in operation or when the DLN controls are not in the premixed (low-NO_X mode). For units that do not produce electrical or thermal output, the data must represent the full range of normal process operation. The highest hourly NO_X concentration in ppm shall be the MPC.

* * * * *

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. 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. 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) * * * For the purposes of this section, 2.1.2.2, a ''certified'' CEMS means a CEM system that has met the applicable certification requirements of either: this part, or part 60 of this chapter, or a State CEM program, or the source operating permit. * * *

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 paragraph 2.1.2.4(e) of this section, 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. * * *

* * * * *

(f) * * * However, if the default high range option in paragraph (e) of this section is selected, the full-scale of the low measurement range shall not exceed five times the MEC value (where the MEC is rounded upward to the next highest multiple of 10 ppm). * * *

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. * * *

* * * * *

2.1.4 Flow Monitors

* * * * *

2.1.4.1 Maximum Potential Velocity and Flow Rate

* * * If using test values, use the highest average velocity (determined from the Method 2 traverses) measured at or near the maximum unit operating load (or, for units that do not produce electrical or thermal output, at the normal process operating conditions corresponding to the maximum stack gas flow rate). * * *

* * * * *

2.1.6 Maximum Potential Moisture Percentage

* * * Alternatively, a default maximum potential moisture value of 15.0 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: Zero to 20 percent of span or an equivalent reference value (*e.g.,* pressure pulse or electronic signal) and 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 the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system, or 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 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 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. Appendix A to part 75 is amended by:

a. Revising section heading and text of section 3.3.1;

b. Revising paragraph (b) of section 3.3.2;

c. In section heading 3.3.3 by removing the words ''Pollutant Concentration'';

d. Revising the second sentence of section 3.3.3;

e. Revising the section heading and text of section 3.3.4;

f. Revising the second sentence of section 3.3.6; and

g. Revising 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 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 difference between the mean value of the monitor measurements and the reference method mean value shall not exceed ±15.0 ppm, wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.2 Relative Accuracy for NO_X-Diluent Continuous Emission Monitoring Systems

* * * * *

(b) For affected units where the average of the reference method measurements of NO_X emission rate during the relative accuracy test audit is less than or equal to 0.200 lb/mmBtu, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ±0.020 lb/mmBtu, wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.3 Relative Accuracy for CO_2 and O_2 Monitors

* * * The relative accuracy test results are also acceptable if the difference between the mean value of the CO_2 or O_2 monitor measurements and the corresponding reference method measurement mean value, calculated using equation A–7 of this appendix, does not exceed ± 1.0 percent CO_2 or O_2.

3.3.4 Relative Accuracy for Flow Monitors

(a) The relative accuracy of flow monitors shall not exceed 10.0 percent at any load (or operating) level at which a RATA is performed (i.e., the low, mid, or high 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 (or operating) level of the relative accuracy test audit is less than or equal to 10.0 fps, the difference between the mean value of the flow monitor velocity measurements and the reference method mean value in fps at that level shall not exceed ± 2.0 fps, wherever the 10.0 percent relative accuracy specification is not achieved.

* * * * *

3.3.6 Relative Accuracy for Moisture Monitoring Systems

* * * The relative accuracy test results are also acceptable if the difference between the mean value of the reference method measurements (in percent H_2O) and the corresponding mean value of the moisture monitoring system measurements (in percent H_2O), calculated using Equation A–7 of this appendix does not exceed ± 1.5 percent H_2O.

3.3.7 Relative Accuracy for NO_X Concentration Monitoring Systems

* * * * *

(b) The relative accuracy for NO_X concentration monitoring systems shall not exceed 10.0 percent. 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 difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ± 15.0 ppm, wherever the 10.0 percent relative accuracy specification is not achieved.

* * * * *

Appendix A to Part 75 [Amended]

50. Appendix A to part 75 is amended by:

a. In the first paragraph of section 4, by adding a new second sentence; and

b. In paragraph (3) of section 4, adding the words ''the appropriate'' before the word ''units'', removing the words ''of the standard'', and 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 emission rates or pollutant mass emissions

(as applicable) in the appropriate units (e.g., lb/hr, lb/mmBtu, tons/hr).

* * * * *

Appendix A to Part 75 [Amended]

51. 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 adding a new first sentence, by revising the word ''Measure'' in the new second sentence to read ''In all other cases, measure'', and by removing the word ''extended'' in the new third 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 section 6.3.2 by adding a new first sentence, by revising the word ''Perform'' in the new second sentence to read ''In all other cases, perform'', and by removing the word ''extended'' before the words ''unit outages'' in the new fifth 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. Adding a new section 6.3.3;

g. In the first sentence of paragraph (a) of section 6.4 by adding the word ''conditional'' before the words ''data validation procedures'';

h. 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'';

i. Revising paragraphs (a) and (c) of section 6.5;

j. In paragraph (b) of section 6.5 by adding the words ''(or operating)'' after the word ''load'';

k. In the first sentence of paragraph (f)(1) of section 6.5 by adding the word ''conditional'' before the words ''data validation procedures'';

l. In the second sentence of paragraph (g) of section 6.5 by removing the words ''SO_2-diluent'';

m. Revising paragraph (a) of section 6.5.1 and paragraph (a) of section 6.5.2;

n. 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)'';

o. In paragraph (c) of section 6.5.2 by adding the words ''(or three operating levels)'' after the word ''level(s)'', and by adding the words ''or (e)'' after the words ''paragraph (b)'';

p. In paragraph (d) of section 6.5.2 by adding the words ''(or operating levels)'' after the word ''level(s)'';

q. Adding a new paragraph (e) to section 6.5.2;

r. In section heading 6.5.2.1 by adding the words ''(or Operating)'' after the words ''Normal Load'';

s. Revising paragraph (a) of section 6.5.2.1;

t–v. 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'';

w. Revising paragraphs (c) and (d) of section 6.5.2.1;

x. Revising the first sentence of paragraph (e) of section 6.5.2.1;

y. Revising section 6.5.2.2 section heading and text;

z. Removing and reserving section 6.5.3;

aa. In section 6.5.6 by removing the third sentence;

bb. In paragraph (b)(2) of section 6.5.6 by revising the number ''1.0'' to read ''1.2'';

cc. Adding paragraph (b)(5) to section 6.5.6;

dd. 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)'';

ee. In paragraph (c) of section 6.5.6.3 by removing the words ''§ 75.56(a)(7) or'' and the words '', as applicable'';

ff. 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

gg. In section 6.5.10 by adding a comma after the number ''7D'', and by adding a new sentence to the end of the paragraph.

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

The following monitors and ranges are exempted from the 7-day calibration error test requirements of this part: The SO_2, NO_X, CO_2 and O_2 monitors installed on peaking units (as defined in § 72.2 of this chapter); and any SO_2 or NO_X measurement range with a span value of 50 ppm or less. * * *

* * * * *

6.3.2 Flow Monitor 7-day Calibration Error Test

Flow monitors installed on peaking units (as defined in § 72.2 of this chapter) are exempted from the 7-day calibration error test requirements of this part. * * *

* * * * *

6.3.3 For gas or flow monitors installed on peaking units, the exemption from performing the 7-day calibration error test applies as long as the unit continues to meet the definition of a peaking unit in § 72.2 of this chapter. However, if at the end of a particular calendar year or ozone season, it is determined that peaking unit status has been lost, the owner or operator shall perform a diagnostic 7-day calibration error test of each monitor installed on the unit, by no later than December 31 of the following calendar year.

* * * * *

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 O_2 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 as otherwise provided in paragraph (b) or (e) of this section, 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.

* * * * *

(e) For flow monitors installed on units that do not produce electrical or thermal output, the flow RATAs for initial certification or recertification may be done at fewer than three operating levels, if:

(1) The owner or operator provides a technical justification in the hardcopy portion of the monitoring plan for the unit required under § 75.53(e)(2), demonstrating that the unit operates at only one level or two levels during normal operation (excluding unit startup and shutdown). Appropriate documentation and data must be provided to support the claim of single-level or two-level operation; and

(2) The justification provided in paragraph (e)(1) of this section is deemed to be acceptable by the permitting authority.

6.5.2.1 Range of Operation and Normal Load (or Operating) 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 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 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 of 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'' with the word ''minimum'' in the definitions of ''MPV,'' ''H_f,'' ''% O_{2d},'' and ''% H_2O,'' and replace the word ''minimum'' with the word ''maximum'' in the definition of ''CO_{2d}.'' Alternatively, 0.0 ft/sec may be used as the lower boundary of the range of operation.

* * * * *

(c) Units that do not produce electrical or thermal output are exempted from the requirements of this paragraph, (c). 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.

(d) Determination of normal load (or operating level)

(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, the normal operating level(s) shall be determined using sound engineering judgment, based on knowledge of the unit and operating experience with the industrial process.

(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. * * *

6.5.2.2 Multi-Load (or Multi-Level) Flow RATA Results

For each multi-load (or multi-level) flow RATA, calculate the flow monitor relative accuracy at each operating level. If a flow monitor relative accuracy test is failed or aborted due to a problem with the monitor on any level of a 2-level (or 3-level) relative accuracy test audit, the RATA must be repeated at that load (or operating) level. However, the entire 2-level (or 3-level) relative accuracy test audit does not have to be repeated unless the flow monitor polynomial coefficients or K-factor(s) are changed, in which case a 3-level RATA is required (or, a 2-level RATA, for units demonstrated to operate at only two levels, under section 6.5.2(e) of this appendix).

6.5.3 [Reserved]

* * * * *

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 flow 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. 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

$$\sum_{i=1}^{n}$$

in the list of defined variables for Eq. A–7 to read

$$``\sum_{i=1}^{n} di"$$

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, in the last sentence, by revising the word'' NO_X'' to read ''NO_X-diluent'';

g. Adding a new paragraph (g) to section 7.6.5;

h. In paragraph (a) of section 7.7 by removing the fourth sentence;

i. Revising paragraph (b) of section 7.7;

j. 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;

k. 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;

l. 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

m. 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 used to determine NO_X mass emissions under subpart H of this part, and flow monitors using the following procedures.* * *

* * * * *

7.6 Bias Test and Adjustment Factor

* * * * *

7.6.5 Bias Adjustment

* * * * *

(g) For units that do not produce electrical or thermal output, the provisions of paragraphs (a) through (f) of this section apply, except that the terms, ''single-load'', ''2-load'', ''3-load'', and ''load level'' shall be replaced, respectively, with the terms, ''single-level'', ''2-level'', ''3-level'', and ''operating level''.

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. For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack (e.g., a unit with a wet SO_2 scrubber), determine Q_{ref} separately for each stack at the time of the normal load flow RATA. Round off the value of R_{ref} to two decimal places.

(c) * * *

Where:

* * *

(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.

* * * * *

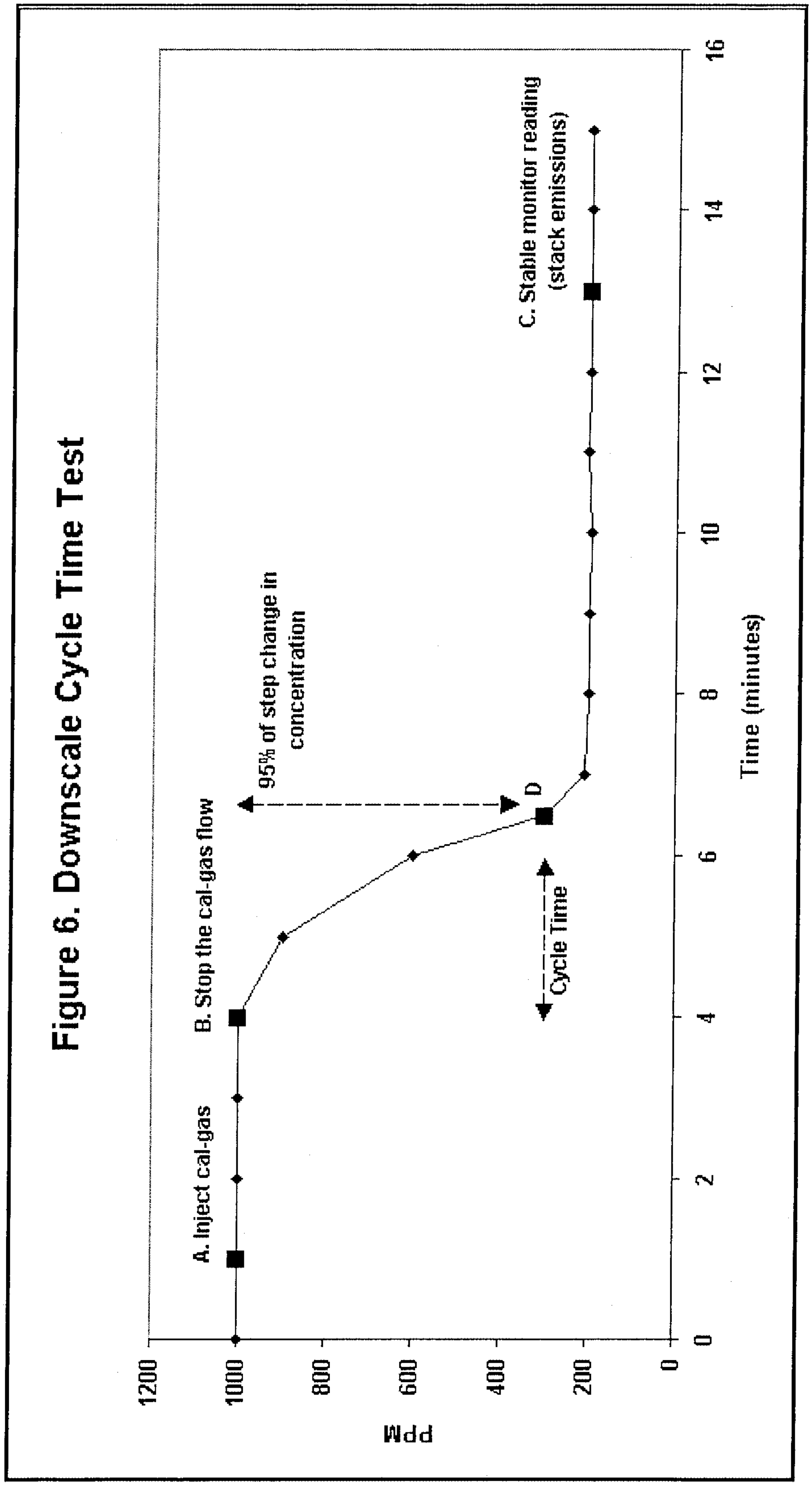

Figure 6. Downscale Cycle Time Test

* * * * *

53. Appendix B to part 75 is amended by:

a. Adding a fourth sentence to section 1;

b. Removing the word ''and'' before the words ''section 2.1.5.1'' in the second sentence of section 1.3.1; and

c. Removing the words ''unit manufacturer's'' in the first sentence of section 1.3.6.

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.

* * * * *

Appendix B to Part 75 [Amended]

54. Appendix B to Part 75 is amended by:

a. In paragraph (a) of section 2.1.4 by removing the words ''(or exceeds 10 ppm, for span values <200 ppm)'' in the first sentence, by adding the words ''of appendix A to this part'' after ''Equation A–6'' in the second sentence, and by adding a new third sentence after the second sentence;

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 section 2.2.2, by revising the words ''section 2.2.3(f)'' to read ''section 2.2.3(g)'';

d. In paragraph (c) of section 2.2.3 by adding a third sentence;

e. In the second sentence of paragraph (e) of section 2.2.3 by removing the words ''or SO_2-diluent'';

f. In paragraph (b) of section 2.2.4 by adding the words ''first unit operating'' before the words ''hour following'' in the first sentence;

g. 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;

h. Revising the third sentence of paragraph (a)(1) of section 2.2.5;

i. In paragraph (a)(3) of section 2.2.5 by adding the word ''rate'' after the words ''heat input'';

j. 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'';

k. Adding a sentence at the end of paragraph (b)(4) of section 2.2.5;

l. Revising the introductory text of paragraph (c) of section 2.2.5;

m. In paragraph (c)(1) of section 2.2.5 by removing the semicolon and adding in its place a period after the word ''sub-bituminous)'' and by adding a new third sentence;

n. In paragraph (c)(8) of section 2.2.5 by removing the second sentence and adding two new sentences in its place;

o. 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'';

p. Revising paragraph (b) of section 2.2.5.1;

q. Revising section 2.2.5.2;

r. In paragraph (a) of section 2.2.5.3 by adding the words ''either the hour in which the abbreviated flow-to-load test is passed, or'' after the word ''until'' in the second sentence, and by revising the word ''The'' at the beginning of the third sentence to read ''If the latter option is selected, the'';

s. In the second sentence of paragraph (b) of section 2.2.5.3 by revising the number ''5.0'' to read ''10.0'';

t. 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;

u. Removing and reserving paragraphs (b) and (g) of section 2.3.1.2;

v. 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;

w. 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)'';

x. 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'';

y. 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'';

z. In section heading 2.3.1.3 by adding the words ''(or Operating)'' after the words ''RATA Load'';

aa. 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)'';

bb. Revising paragraphs (b) and (c) of section 2.3.1.3;

cc. In paragraph (c) of section 2.3.2 by adding a new third sentence;

dd. In paragraph (d) of section 2.3.2 by adding the words ''(or single level)'' after the word ''single-load'' and adding the words ''(or multiple level)'' after the word ''multiple-load'', and in paragraphs (d) and (f) of section 2.3.2 by adding the words ''(or operating levels(s))'' after the words ''load level(s)'', the words ''(or 3-level)'' after the words ''3-load'', and the words '', except as otherwise provided in section 2.3.1.3(c)(5) of this appendix'' immediately before the period at the end of each paragraph;

ee. By revising paragraph (e) of section 2.3.2;

ff. Revising paragraph (a) of section 2.3.3;

gg. Revising paragraph (b) of section 2.4;

hh. Revising footnote 2 of Figure 1 to Appendix B of Part 75; and

ii. In Figure 2 to Appendix B of Part 75 by removing the entire entry for ''Flow (Phase I)'' and revising the phrase ''Flow (Phase II)'' in the first column to read ''Flow''.

The revisions and additions read as follows:

2. Frequency of Testing

* * * * *

2.1 Daily Assessments

* * * * *

2.1.4 Data Validation

(a) * * * In addition, an SO_2 or NO_X monitor for which the calibration error exceeds 5.0 percent of the span value shall not be considered out-of-control if |R–A| in Equation A–6 does not exceed 5.0 ppm (for span values ≤50 ppm), or if |R–A| does not exceed 10.0 ppm (for span values > 50 ppm, but ≤ 200 ppm). * * *

* * * * *

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) * * * 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) * * *

(4) * * * 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, except as otherwise specified in section 2.3.1.3 of this appendix.

* * * * *

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

* * * * *

(b) For flow monitors installed on peaking units and bypass stacks, and for flow monitors that qualify to perform only single-level RATAs under section 6.5.2(e) of appendix A to this part, all required semiannual or annual relative accuracy test audits shall be single-load (or single-level) audits at the normal load (or operating level), as defined in section 6.5.2.1(d) of appendix A to this part.

(c) For all other flow monitors, the RATAs shall be performed as follows:

(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, or (if applicable) at the operating levels determined under section 6.5.2(e) 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, except for flow monitors that are exempted from 3-load (or 3-level) RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.

(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 that are exempted from 3-load (or 3-level) RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part. For monitors so exempted under section 6.5.2(b), a single-load flow RATA is required. For monitors so exempted under section 6.5.2(e), either a single-level RATA or a 2-level RATA is required, depending on the number of operating levels documented in the monitoring plan for the unit.

(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.

* * * * *

2.3.3 RATA Grace Period

(a) The owner or operator has a grace period of 720 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 720 consecutive stack operating hours, as defined in § 72.2 of this chapter), in which to complete the required RATA for a particular CEMS whenever:

(1) A required RATA has not been performed by the end of the QA operating quarter in which it is due; or

(2) Five consecutive calendar years have elapsed without a required 3-load flow RATA having been conducted; or

(3) For a unit which is conditionally exempted under § 75.21(a)(7) from the SO_2 RATA requirements of this part, an SO_2 RATA has not been completed by the end of the calendar quarter in which the annual usage of fuel(s) with a sulfur content higher than very low sulfur fuel (as defined in § 72.2 of this chapter) exceeds 480 hours; or

(4) Eight successive calendar quarters have elapsed, following the quarter in which a RATA was last performed, without a subsequent RATA having been done, due either to infrequent operation of the unit(s) or frequent combustion of very low sulfur fuel, as defined in § 72.2 of this chapter (SO_2 monitors, only), or a combination of these factors.

* * * * *

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 (or single-level) flow RATA is specifically required under section 2.3.1.3(b) of this appendix 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, bypass stacks, or units that qualify for single-level RATA testing under section 6.5.2(e) of this appendix, conduct all RATAs at a single, normal load (or operating level). For other flow monitors, conduct annual RATAs at two load levels (or operating levels). Alternating single-load and 2-load (or single-level and 2-level) RATAs may be done if a monitor is on a semiannual frequency. A single-load (or single-level) RATA may be done in lieu of a 2-load (or 2-level) RATA if, since the last annual flow RATA, the unit has operated at one load level (or operating level) for ≥ 85.0 percent of the time. A 3-level RATA is required at least once every five calendar years and whenever a flow monitor is re-linearized, except for flow monitors exempted from 3-level RATA testing under section 6.5.2(b) or 6.5.2(e) of appendix A to this part.

* * * * *

55. Appendix C to part 75 is amended by:

a. In the section heading of section 2 by revising the word ''Load-Based'' to read ''Load-based'' and by adding the words '', NO_X Concentration,'' after the words ''Flow Rate''; and

b. Adding a new section 3.

The revisions and additions read as follows:

Appendix C to Part 75—Missing Data Estimation Procedures

* * * * *

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 (as applicable) 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 in the previous 3 years:

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 rates, 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 § 75.71(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.

Appendix D Section 1 [Amended]

56. Appendix D to Part 75 is amended by removing the final sentence of section 1.2.

57. 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. Revising paragraph (c) of section 2.1.6;

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 paragraph (a) of section 2.1.6.1 by adding the word ''upscale'' after the word ''other'' in the second sentence 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 ''$(Heat\ Input)_{avg}$'' under Eq. D–1c;

x. Adding a new paragraph (e) to section 2.1.7.1;

y. In paragraph (a) of section 2.1.7.2 by adding a new third sentence;

z. Revising paragraph (b) of section 2.1.7.2;

aa. In the variable for ''$(Heat\ Input)_h$'' 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'';

bb. Revising paragraph (d) of section 2.1.7.2;

cc. Adding a third sentence to paragraph (h) of section 2.1.7.2;

dd. Revising paragraph (a) of section 2.1.7.3;

ee. Adding a second sentence to paragraph (b) of section 2.1.7.3;

ff. 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)'';

gg. 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'';

hh. Revising Table D–3 in section 2.1.7.5 and Table D–4 in section 2.2;

ii. 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)'';

jj. Revising paragraph (b) of section 2.2.4.2.

kk. 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'' to read, respectively, the words ''following conservative, assumed values'' and ''assumed values'';

ll. Revising paragraph (d) of section 2.2.4.3;

mm. Revising Table D–5 in paragraph (b) of section 2.3;

nn. In section 2.3.1.3 by adding the words ''or Equation D–4 (if daily or hourly fuel sampling is used)'' at the end of the first sentence;

oo. Revising sections 2.3.1.4, 2.3.2.4, and 2.3.6;

pp. Revising section 2.3.2.1.1 and Equation D–1h;

qq. Removing and reserving section 2.3.2.1.2;

rr. Revising sections 2.3.3.1.1 and 2.3.3.2;

ss. In section 2.3.4.3 by adding a new second sentence;

tt. In section 2.3.4.3.1 by revising the fourth sentence;

uu. Revising section 2.3.4.3.2;

vv. Revising paragraph (a) of section 2.3.5;

ww. Adding section 2.3.7;

xx. In section 2.4.1 by removing a reference to ''2.3.3.1,'' in the first sentence, by removing the second sentence and adding two new sentences in its place, and by revising Table D–6;

yy. Revising sections 2.4.2, 2.4.2.1, and 2.4.2.2; adding sections 2.4.2.2.1 and 2.4.2.2.2; revising section 2.4.2.3; and adding sections 2.4.2.3.1 through 2.4.2.3.4; and

zz. In section 2.4.3 by adding a second sentence.

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). 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. 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.

* * * * *

2.1.4.1 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 its Federal, State or local 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 (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

* * * * *

(c) For orifice-, nozzle-, and venturi-type flowmeters, either perform the required flowmeter accuracy testing using the procedures in section 2.1.5.2 of this appendix or perform a transmitter accuracy test for the initial certification and once every four fuel flowmeter QA operating quarters thereafter. Perform a primary element visual inspection for the initial certification and once every 12 calendar quarters thereafter, according to the procedures in sections 2.1.6.1 through 2.1.6.4 of this appendix for periodic 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.

* * * * *

(e) If a unit co-fires different fuels (*e.g.,* oil and natural gas) as its normal mode of operation, the gross heat rate option in paragraph (c) of this section may be used to determine a value of $(GHR)_{base}$, as follows. Derive the baseline data during co-fired hours. Then, use Equation D–1c to calculate $(GHR)_{base}$, making sure that each hourly unit heat input rate used to calculate $(Heat\ Input)_{avg}$ includes the contribution of each type of fuel.

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, Lh 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) Evaluate the calculated flow rate-to-load ratios (or gross heat rates) as follows.

(1) Perform a separate data analysis for each fuel flowmeter system following the procedures of this section. Base each analysis on a minimum of 168

hours of data. If, for a particular fuel flowmeter system, 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 system accuracy test was performed, a flow-to-load (or GHR) evaluation is not required for that flowmeter system for that calendar quarter. A one-quarter extension of the deadline for the next fuel flowmeter system 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) For a unit that normally co-fires different types of fuel (e.g., oil and natural gas), include the contribution of each type of fuel in the value of (Heat Input)$_h$, when using Equation D–1e.

* * * * *

(h) * * * For units that normally co-fire different types of fuel, if the GHR option is used, apply the test results to each fuel flowmeter system used during the quarter.

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. Specifically, the R_h or $(GHR)_h$ values for the following hours may be considered non-representative:

(1) For units that do not normally co-fire fuels, any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; or

(2) Any hour for which the load differed by more than ± 15.0 percent from the load during either the preceding hour or the subsequent hour; or

(3) For units that normally co-fire different fuels, any hour in which the unit burned only one type of fuel; or

(4) Any hour for which the unit load was in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in the lower 25.0 percent of the range is considered normal for the unit).

(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.

* * * * *

2.1.7.5 Test Results

* * * * *

Table D–3.—Baseline Information and Test Results For Fuel Flow-to-Load Test

Plant name:________________ State:____ ORIS code:____________

Unit/pipe ID #:___________ Fuel flowmeter system ID :___ Calendar quarter (1st, 2nd, 3rd, 4th) and year:_________

Range of operation: ________ to ________ MWe or klb steam/hr (indicate units)

Reported Data Elements	
Baseline period	Quarterly analysis
Completion date and time of most recent QA sequence, i.e., primary element inspection and transmitter calibration (orifice-, nozzle-, and venturi-type flowmeters only). __/__/__ __:__	Number of hours excluded from quarterly average due to co-firing different fuels (where co-firing is not normal operation):______ hrs.
Completion date and time of most recent flowmeter or accuracy test (all other flowmeters) __/__/__ __:__	Number of hours excluded from quarterly average due to single-fuel combustion (where co-firing is normal operation):______ hrs.
Beginning date and time of baseline period __/__/__ __:__	Number of hours excluded from quarterly average due to ramping load:______ hrs.
End date and time of baseline period __/__/__ __:__	Number of hours in the lower 25.0 percent of the range of operation excluded from quarterly average: ______hrs.
Average fuel flow rate______________ (100 scfh for gas and lb/hr for oil)	Number of hours included in quarterly average:______ hrs.
	Quarterly percentage difference between hourly ratios and baseline ratio:______ percent.
Average load;_______________ (MWe or 1000 lb steam/hr)	Test result: pass, fail.
Baseline fuel flow-to-load ratio _________ Units of fuel flow-to-load:_________	
Baseline GHR: ______ Units of fuel flow-to-load:_________	
Number of hours excluded from baseline ratio or GHR due to ramping load: ______	
Number of hours in the lower 25.0 percent of the range of operation excluded from baseline ratio or GHR: ______hrs.	

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 (except for missing data hours)
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.
	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.

* * * * *

2.2.4.2 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, consistent with section 2.3.7 of this appendix, begin to use the actual sampled value for sulfur content, gross calorific value, or density of fuel to calculate SO2 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 SO2 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*

* * * * *

(b) * * *

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 Total Sulfur Content	Pipeline Natural Gas with total sulfur content less than or equal to 0.5 grains/100scf * Sampling is not required if a valid contract or tariff sheet is used to qualify. * If fuel sampling and analysis is used to qualify, sample annually and whenever the fuel supply source changes.	1. If a contract or tariff sheet is used to qualify, use 0.0006 lb/mmBtu 2. If fuel sampling and analysis is used to qualify, use 0.0006 lb/mmBtu, provided that the results of the required annual samples do not exceed 0.5 grains/100 scf of total sulfur. If the results of an annual sample exceed 0.5 grains/100 scf, re-classify the fuel as appropriate and determine the SO_2 emission rate to be used in the calculations, using the applicable procedures in section 2.3.2 or 2.3.3 of this appendix
	Natural Gas with total sulfur content less than or equal to 20.0 grains /100scf * Sampling is not required if a valid contract or tariff sheet is used to qualify. * If fuel sampling and analysis is used to qualify, sample annually and whenever the fuel supply source changes.	Default SO_2 emission rate calculated from Eq. D-1h, using either: 1. The maximum total sulfur content specified in the fuel contract or tariff sheet, if a contract or tariff sheet is used to qualify; or 2. The total sulfur content, based on the most recent fuel sampling and analysis. If multiple samples are taken, the results may be averaged before using Equation D-1h.
	Any gaseous fuel transmitted by pipeline, having a "low sulfur variability", as shown under section 2.3.6 of this appendix. * Either sample daily or, if Eq. D-1h is used to calculate a default SO_2 emission rate, sample annually.	* If daily sampling is performed, use either: 1. Actual value from the daily sample; or 2. Highest value from previous 30 samples. * If the option to use Eq. D-1h is selected, use a default SO_2 emission rate, calculated using the higher of: 1. The 90^{th} percentile value of the total sulfur content, obtained in the 720-hr demonstration under section 2.3.6; or 2. The actual total sulfur content from the most recent annual sample. If multiple samples are taken, the results may be averaged before using Equation D-1h.

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
	Any gaseous fuel transmitted by pipeline, having a maximum total sulfur content ≤ 20 grains/100 scf and "high sulfur variability", as shown under section 2.3.6 of this appendix. * Either sample hourly or, if Eq. D-1h is used to calculate a default SO_2 emission rate, sample annually.	* If hourly sampling is performed, use the actual hourly value * If the option to use Eq. D-1h is selected, use a default SO_2 emission rate, calculated using the higher of: 1. The maximum value of the total sulfur content, obtained in the 720-hr demonstration under section 2.3.6; or 2. The actual total sulfur content from the most recent annual sample. If multiple samples are taken, the results may be averaged before using Equation D-1h.
	Any gaseous fuel transmitted by pipeline, having a maximum total sulfur content > 20 grains/100 scf and "high sulfur variability", as shown under section 2.3.6 of this appendix. * Sample hourly	Actual hourly sulfur content of the gas
	Any gaseous fuel delivered in shipments or lots * Sample each lot or shipment.	1. Actual total sulfur content from most recent shipment; or 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]
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]

Parameter	Fuel type and sampling frequency	Value used in calculations (except for missing data hours)
	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 $\geq$ 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 gaseous fuel not demonstrated to have a "low GCV variability" under section 2.3.5 * 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 0.5 grains/100scf or less. The demonstration must be made using one of the following sources of information:

(1) The gas quality characteristics specified by a purchase contract, tariff sheet, or by a pipeline transportation contract; or

* * * * *

(2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of pipeline natural gas in § 72.2 of this chapter; or

(3) If the requirements of paragraphs (a)(1) and (a)(2) of this section cannot be met, a fuel may initially qualify as pipeline natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the gross calorific value (GCV) or percent methane, and the results of the sample analysis show that the fuel meets the definition of pipeline natural gas in § 72.2 of this chapter. Use the sampling methods specified in sections 2.3.3.1.2 and 2.3.4 of this appendix. The required fuel sample may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of pipeline natural gas in § 72.2 of this chapter.

(b) If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of pipeline natural gas in § 72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of pipeline natural gas.

(c) If several affected units are supplied by a common source of gaseous fuel, a single sampling result may be applied to all of the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term "other gaseous fuel(s)" excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.

(d) If the results of fuel sampling and analysis under paragraph (a)(2), (a)(3), or (b) of this section show that the fuel does not qualify as pipeline natural gas, proceed as follows:

(1) If the fuel still qualifies as natural gas under section 2.3.2.4 of this appendix, re-classify the fuel as natural gas and determine the appropriate default SO_2 emission rate for the fuel, according to section 2.3.2.1.1 of this appendix; or

(2) If the fuel does not qualify either as pipeline natural gas or natural gas, re-classify the fuel as "other gaseous fuel" and implement the procedures of section 2.3.3 of this appendix, within 180 days of the end of the quarter in which the disqualifying sample was taken. In addition, the owner or operator shall use Equation D–1h in this appendix to calculate a default SO_2 emission rate for the fuel, based on the results of the sample analysis that exceeded 20 grains/100 scf of total sulfur, and shall use that default emission rate to report SO_2 mass emissions under this part until section 2.3.3 of this appendix has been fully implemented.

(e) If a fuel qualifies as pipeline natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as pipeline natural gas based on fuel sampling and analysis, on-going sampling of the fuel's sulfur content is required annually and whenever the fuel supply source changes. For the purposes of this paragraph, (e), sampling ''annually'' means that at least one sample is taken in each calendar year. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

(f) On-going sampling of the GCV of the pipeline natural gas is required under section 2.3.4.1 of this appendix.

(g) For units that are required to monitor and report NO_X mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements in paragraphs (a) and (e) of this section to document the total sulfur content of the pipeline natural gas.

2.3.2 Natural Gas Combustion

* * * * *

2.3.2.1.1 In lieu of daily sampling of the sulfur content of the natural gas, the owner or operator may either use the total sulfur content specified in a contract or tariff sheet as the SO_2 default emission rate or may calculate the default SO_2 emission rate based on fuel sampling results, using Equation D–1h. In Equation D–1h, the total sulfur content and GCV values shall be determined in accordance with Table D–5 of this appendix. Round off the calculated SO_2 default emission rate to the nearest 0.0001 lb/mmBtu.

$$ER = \left[\frac{2.0}{7000}\right] \times \left[10^6\right] \times \left[\frac{S_{total}}{GCV}\right] \qquad \text{(Eq. D-1h)}$$

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 [Reserved]

* * * * *

2.3.2.4 Documentation that a Fuel Is 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 20.0 grains/100 scf or less. This demonstration must be made using one of the following sources of information:

(1) The gas quality characteristics specified by a purchase contract, tariff sheet, or by a transportation contract; or

(2) Historical fuel sampling data for the previous 12 months, documenting the total sulfur content of the fuel and the GCV and/or percentage by volume of methane. The results of all sample analyses obtained by or provided to the owner or operator in the previous 12 months shall be used in the demonstration, and each sample result must meet the definition of natural gas in § 72.2 of this chapter; or

(3) If the requirements of paragraphs (a)(1) and (a)(2) of this section cannot be met, a fuel may initially qualify as natural gas if at least one representative sample of the fuel is obtained and analyzed for total sulfur content and for either the gross calorific value (GCV) or percent methane, and the results of the sample analysis show that the fuel meets the definition of natural gas in § 72.2 of this chapter. Use the sampling methods specified in sections 2.3.3.1.2 and 2.3.4 of this appendix. The required fuel sample may be obtained and analyzed by the owner or operator, by an independent laboratory, or by the fuel supplier. If multiple samples are taken, each sample must meet the definition of natural gas in § 72.2 of this chapter.

(b) If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of natural gas in § 72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of natural gas.

(c) If several affected units are supplied by a common source of gaseous fuel, a single sampling result may be applied to all of the units and it is not necessary to obtain a separate sample for each unit, provided that the composition of the fuel is not altered by blending or mixing it with other gaseous fuel(s) when it is transported from the sampling location to the affected units. For the purposes of this paragraph, the term ''other gaseous fuel(s)'' excludes compounds such as mercaptans when they are added in trace quantities for safety reasons.

(d) If the results of fuel sampling and analysis under paragraph (a)(2), (a)(3), or (b) of this section show that the fuel does not qualify as natural gas, the owner or operator shall re-classify the fuel as ''other gaseous fuel'' and shall implement the procedures of section 2.3.3 of this appendix, within 180 days of the end of the quarter in which the disqualifying sample was taken. In addition, the owner or operator shall use Equation D–1h in this appendix to calculate a default SO_2 emission rate for the fuel, based on the results of the sample analysis that exceeded 20 grains/100 scf of total sulfur, and shall use that default emission rate to report SO_2 mass emissions under this part until section 2.3.3 of this appendix has been fully implemented.

(e) If a fuel qualifies as natural gas based on the specifications in a fuel contract or tariff sheet, no additional, on-going sampling of the fuel's total sulfur content is required, provided that the contract or tariff sheet is current, valid and representative of the fuel combusted in the unit. If the fuel qualifies as natural gas based on fuel sampling and analysis, the owner or operator shall sample the fuel for total sulfur content at least annually and when the fuel supply source changes. For the purposes of this paragraph, (e), sampling ''annually'' means that at least one sample is taken in each calendar year. The effective date of the annual total sulfur sampling requirement is January 1, 2003.

(f) On-going sampling of the GCV of the natural gas is required under section 2.3.4.2 of this appendix.

(g) For units that are required to monitor and report NO_X mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements in paragraphs (a) and (e) of this section to document the total sulfur content of the natural gas.

2.3.3 SO_2 Mass Emissions From Any Gaseous Fuel

* * * * *

2.3.3.1 Sulfur Content Determination

2.3.3.1.1 Analyze the total sulfur content of the gaseous fuel in grains/100 scf, at the frequency specified in Table D–5 of this appendix. That is: for fuel delivered in discrete shipments or lots, sample each shipment or lot. For fuel transmitted by pipeline, sample hourly unless a demonstration is provided under section 2.3.6 of this appendix showing that the gaseous fuel qualifies for less frequent (*i.e.,* daily or annual) sampling. If daily sampling is required, determine the sulfur content using either manual sampling or a gas chromatograph. If hourly sampling is required, determine the sulfur content using a gas chromatograph. For units that are required to monitor and report NO_X mass emissions and heat input under subpart H of this part, but which are not affected units under the Acid Rain Program, the owner or operator is exempted from the requirements of this section to document the total sulfur content of the gaseous fuel.

* * * * *

2.3.3.2 SO_2 Mass Emission Rate

Calculate the SO_2 mass emission rate for the gaseous fuel, in lb/hr, using equation D–4 or D–5 (as applicable) in section 3.3.1 of this appendix. Equation D–5 may only be used if a demonstration is performed under section 2.3.6 of this appendix, showing that the fuel qualifies to use a default SO_2 emission rate to account for SO_2 mass emissions under this part. Use the appropriate sulfur content, in equation D–4 or D–5, as specified in Table D–5 of this appendix. If the fuel qualifies to use Equation D–5, the default SO_2 emission rate shall be calculated using Equation D–1h in section 2.3.2.1.1 of this appendix, replacing the words ''natural gas'' in the equation nomenclature with the words, ''gaseous fuel''. In all cases, for reporting purposes, apply the results of the required periodic total sulfur samples in accordance with the provisions of section 2.3.7 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 2.3.7 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 tariff sheet, 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 for which the owner or operator performs the 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 (as described in section 2.3.4.1 of this appendix). 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 tariff sheet, 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.

* * * * *

2.3.6 Demonstration of Fuel Sulfur Variability

(a) This 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 a particular gaseous fuel qualifies to use a default SO_2 emission rate (calculated using Equation D–1h in section 2.3.2.1.1 of this appendix) for the purpose of reporting hourly SO_2 mass emissions under this part. To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content of the gaseous fuel (in gr/100 scf). The demonstration data shall be obtained using either manual hourly sampling or an on-line gas chromatograph (GC) capable of determining fuel total sulfur content on an hourly basis. For gaseous fuel produced by a variable process, the data shall be representative of all process operating conditions including seasonal or annual variations which may affect fuel sulfur content.

(b) If the data are collected with an on-line GC, reduce the data to hourly average values of the total sulfur content of the fuel. If manual hourly sampling is used, the results of each hourly sample analysis shall be the total sulfur value for that hour. Express all hourly average values of total sulfur content in units of grains/ 100 scf. Use all of the hourly average values of total sulfur content in grains/100 scf to calculate the mean value and the standard deviation. Also determine the 90th percentile and maximum hourly values of the total sulfur content for the data set. If the standard deviation of the hourly values from the mean does not exceed 5.0 grains/100 scf, the fuel has a low sulfur variability. If the standard deviation exceeds 5.0 grains/100 scf, the fuel has a high sulfur variability. Based on the results of this determination, establish the required sampling frequency and SO_2 mass emissions methodology for the gaseous fuel, as follows:

(1) If the gaseous fuel has a low sulfur variability (irrespective of the total sulfur content), the owner or operator may either perform daily sampling of the fuel's total sulfur content using manual sampling or a GC, or may report hourly SO_2 mass emissions data using a default SO_2 emission rate calculated by substituting the 90th percentile value of the total sulfur content in Equation D–1h.

(2) If the gaseous fuel has a high sulfur variability, but the maximum hourly value of the total sulfur content does not exceed 20 grains/100 scf, the owner or operator may either perform hourly sampling of the fuel's total sulfur content using an on-line GC, or may report hourly SO_2 mass emissions data using a default SO_2 emission rate calculated by substituting the maximum value of the total sulfur content in Equation D–1h.

(3) If the gaseous fuel has a high sulfur variability and the maximum hourly value of the total sulfur content exceeds 20 grains/100 scf, the owner or operator shall perform hourly sampling of the fuel's total sulfur content, using an on-line GC.

(4) Any gaseous fuel under paragraph (b)(1) or (b)(2) of this section, for which

the owner or operator elects to use a default SO_2 emission rate for reporting purposes is subject to the annual total sulfur sampling requirement under section 2.3.2.4(e) of this appendix.

2.3.7 Application of Fuel Sampling Results

For reporting purposes, apply the results of the required periodic fuel samples described in Tables D–4 and 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 annual samples of total sulfur content:

(1) For pipeline natural gas, use the results of annual sample analyses in the calculations only if the results exceed 0.5 grains/100 scf. In that case, if the fuel still qualifies as natural gas, follow the procedures in paragraph (b)(2) of this section. If the fuel does not qualify as natural gas, the owner or operator shall implement the procedures in section 2.3.3 of this appendix, in the time frame specified in sections 2.3.1.4(d) and 2.3.2.4(d) of this appendix;

(2) For natural gas, apply the results of the most recent sample, beginning at the date of the sample;

(3) For other gaseous fuels with an annual sampling requirement under section 2.3.6(b)(4) of this appendix, use the sample results in the calculations only if the results exceed the 90th percentile value or maximum value (as applicable) from the 720-hour demonstration of fuel sulfur content and variability under section 2.3.6 of this appendix.

(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, starting from the date on which the sample was taken; 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, starting from the date on which the sample was taken. 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, from the date on which the sample was taken until the date on which the next sample is taken; 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, starting from the date on which the sample was taken. 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.

(e) When the owner or operator elects to use assumed values in the calculations, the results of periodic samples of sulfur content and GCV which show that the assumed value has not been exceeded need not be reported. Keep these sample results on file, in a format suitable for inspection.

(f) Notwithstanding the requirements of paragraphs (b) through (d) of this section, in cases where the sample results are provided to the owner or operator by the supplier of the fuel, the owner or operator shall begin using the sampling results on the date of receipt of those results, rather than on the date that the sample was taken.

2.4 Missing Data Procedures

* * * * *

2.4.1 Missing Data for Oil and Gas Samples

* * * Except for the annual samples of fuel sulfur content required under sections 2.3.1.4(e), 2.3.2.4(e) and 2.3.6(b)(5) of this appendix, the missing data values in Table D–6 shall be reported whenever the results of a required sample of sulfur content, GCV or density is missing or invalid in the current calendar year, irrespective of which reporting option is selected (i.e., actual value, contract value or highest value from the previous year). For the annual samples of fuel sulfur content required under sections 2.3.1.4(e), 2.3.2.4(e) and 2.3.6(b)(5) of this appendix, if a valid annual sample has not been obtained by the end of a particular calendar year, the appropriate missing data value in Table D–6 shall be reported, beginning with the first unit operating hour in the next calendar year. * * *

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. For pipeline natural gas, where annual sampling is required, substitute 0.002 lb/mmBtu for each hour of the missing data period. 2. For natural gas (or other gaseous fuel that qualifies to use a default SO_2 emission rate under section 2.3.6 of this appendix), where annual sampling is required, substitute 1.5 times the default SO_2 emission rate in use at the time of the missing data period. 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. 4. For any gaseous fuel sampled hourly, the highest total sulfur content value from the previous 720 hourly samples.
Gas GCV/Heat Content	110,000 Btu/100 scf for pipeline natural gas, natural gas or landfill gas. 150,000 Btu/100 scf for butane or refinery gas. 210,000 Btu/100 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 (i.e., 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 shall either perform missing data substitution without segregating the fuel flow rate data into bins, or may petition the Administrator under § 75.66 for permission to segregate the data into operational bins. When load ranges 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

If no fuel flow rate data are available for a fuel flowmeter system installed on a peaking unit (as defined in § 72.2 of this chapter), then substitute for each hour of missing data using the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following:

(a) The maximum fuel flow rate the unit is capable of combusting or

(b) The maximum flow rate that the fuel flowmeter can measure (i.e, the upper range value of the flowmeter).

2.4.2.2 Standard Missing Data Procedures—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, use 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. 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 Standard Missing Data Procedures—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, use 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. 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, for a new or newly-affected unit, until 720 hours of quality-assured fuel flowmeter data are 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.

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. Equation D–4 is revised;

c. In the definition of the variable ''GCV_{gas}'' in Equation D–6 in paragraph (b) of 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 paragraph (a) of section 3.4.2 by adding the word ''or'' after the word ''Btu/ton,'';

e. Adding a new paragraph (c) to section 3.4.2;

f. Removing the second sentence in paragraph (a) of section 3.4.3;

g. 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 and reserving Equations D–10 and D–11 and their variable respective definitions;

h. 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'';

i. Revising the section heading of section 3.5;

j. In section heading 3.5.4 by adding the words ''Rate and Heat Input'' after the word ''Input'';

k. Designating the existing text of section 3.5.4 as section 3.5.4.1 and adding section 3.5.4.2 and Equation D–15a following the variable definitions for Equation D–15; and

l. Revising Equation D–16 in section 3.5.5.

The revisions and additions read as follows:

3. Calculations

* * * * *

$$SO_{2_{\text{rate-gas}}} = \left(\frac{2.0}{7000}\right) \times GAS_{rate} \times S_{gas} \qquad \text{(Eq. D-4)}$$

Where:

SO2rate-gas = Hourly mass rate of SO_2 emitted due to combustion of gaseous fuel, lb/hr.
GASrate = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.
Sgas = Sulfur content of gaseous fuel, in grain/100 scf.
2.0 = Ratio of lb SO_2/lb S.
7000 = Conversion of grains/100 scf to lb/100 scf.

* * * * *

3.4.2 Heat Input Rate from the Combustion of Oil

* * * * *

(c) For affected units that are not subject to an Acid Rain emissions limitation, but are regulated under a State or Federal NO_X mass emissions reduction program that adopts the requirements of subpart H of this part, the following alternative method may be used to determine the heat input rate from oil combustion, when the oil flowmeter measures the flow rate of oil volumetrically. In lieu of measuring the oil density and converting the volumetric oil flow rate to a mass flow rate, Equation D–8 may be applied on a volumetric basis. If this option is selected, express the terms OIL_{rate} and GCV_{oil} in Equation D–8 in units of volume rather than mass. For example, the units of OIL_{rate} may be gal/hr and the units of GCV_{oil} may be Btu/gal.

* * * * *

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

3.5.4.1

* * * * *

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

* * * * *

$$HI_{qtr} = \sum_{all\text{-}hours\text{-}in\text{-}qtr} HI_{hr} \qquad \text{(Eq. D-16)}$$

Where:

HIqtr = Total heat input from all fuels combusted during the quarter, mmBtu.

HIqtr = Hourly heat input determined using Equation D–15, mmBtu.

* * * * *

59. Appendix E to Part 75 is amended by revising the second sentence of section 1.1, adding a sentence after the second sentence of section 1.1, and removing and reserving section 1.2.2 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. * * *

1.2 Certification

* * * * *

1.2.2 [Reserved]

Appendix E to Part 75 [Amended]

60. 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, by revising the words ''manufacturer's recommended'' to read ''acceptable'' in the third and fourth sentences, and by adding two new sentences after the first sentence, in each section;

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:

2. Procedure

* * * * *

2.1.4 Emergency Fuel

The designated representative of a unit that is restricted by its Federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available may claim an exemption from the requirements of this appendix for testing the NO_X emission rate during combustion of the emergency fuel. To claim this exemption, 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 emergency fuel, 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. Notwithstanding this requirement, for non-Acid Rain Program units that report NO_X mass emissions and heat input data only during the ozone season under § 75.74(c), if the NO_X emission rate testing is performed outside the ozone season, the new correlation curve may be used beginning with the first unit operating hour in the ozone season immediately following the testing.

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. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. * * *

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. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. * * *

* * * * *

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 sections 2.5.2.1, 2.5.2.2, and 2.5.2.3 of this appendix. Manual substitution of the missing data values required under sections 2.5.2.1 and 2.5.2.2 of this appendix is permitted through March 31, 2003, after which these substitutions must be performed automatically by the data acquisition and handling system. Manual substitution of the missing data values required under section 2.5.2.3 of this appendix is permitted at all times.

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, according to section 2.5.2.1.1 or 2.5.2.1.2 of this appendix, as applicable. Either:

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 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, unless a NO_X correlation curve has been derived for the fuel.

* * * * *

Appendix E Part 75 [Amended]

61. Appendix E to Part 75 is amended by, in section 4 introductory text and section 4.1 by removing the words ''unit manufacturer's'', and in section 4.2 by removing the word ''manufacturer's''.

62. 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 * * *

$$E_q = \frac{\sum_{h=1}^{n} E_h t_h}{2000}$$

* * * * *

Appendix F to Part 75 [Amended]

63. Appendix F to Part 75 is amended, in section 3.3.5, by removing the third sentence, and by revising section 3.5 to read as follows:

3. Procedures for NO_X Emission Rate

* * * * *

3.5 Round all NO_X emission rates to the nearest 0.001 lb/mmBtu.

Appendix F to Part 75 [Amended]

64. 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 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'',''$_{unit}$'', 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 5.8.

The revisions and additions read as follows:

5. Procedures for Heat Input

* * * * *

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.

5.8 Alternate Heat Input Apportionment for Common Pipes

As an alternative to using Equation F–21a or F–21b in section 5.6 of this appendix, 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:

$$HI_i = HI_{CP}\left(\frac{t_{CP}}{t_i}\right)\left[\frac{FF_i t_i}{\sum_{i=1}^{n} FF_i t_i}\right] \qquad \text{(Eq. F-21d)}$$

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.

Appendix F to Part 75 [Amended]

65. 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]

66. 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''; and

b. In section 8.1.2 by revising the definition of the variable ''t_{cs}'' of Equation F–25 and by adding definitions of the variables ''p'' and ''u'' to Equation F–25.

The revisions and additions read as follows:

8. Procedures for NO_X Mass Emissions

* * * * *

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.

* * * * *

67. Appendix G to Part 75 is amended as follows:

a. In the text following the variables in Equation G–1 (the first sentence of which begins with the phrase, ''Collect at least one fuel sample during each week that the unit combusts coal''), designate the first two sentences as section 2.1.1; designate the third sentence as section 2.1.2; and designate the fourth through last sentences as section 2.1.3;

b. In newly designated section 2.1.2, revising the word ''sampling'' to read ''sample''

c. In section 2.2.3 designate the equation as ''(Eq. G–2).''; and

d. Revising section 2.3, by revising the definition of variable ''F_c'' of Equation G–4, and by adding a definition of the variable ''$MWCO_2$'' in Equation G–4.

The revisions and additions 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) * * *

MW CO_2 = Molecular weight of carbon dioxide, 44.0 lb/lb-mole.

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]

68. Appendix G to Part 75 is amended by revising the introductory text of section 3.1.2 and by revising the definition of ''%R'' in Equation G–7 to read as follows:

3. Procedures for Estimating CO_2 Emissions from Sorbent

* * * * *

3.1.2 In lieu of using equation G–5, any owner or operator who operates and maintains a certified SO_2-diluent continuous emission monitoring system (consisting of an SO_2 pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor), for measuring and recording SO_2 emission rate (in lb/mmBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations such as those in EPA Method 19 in appendix A to part 60 of this chapter to estimate the SO_2 emissions removal efficiency of the emission controls, may use the following equations to estimate daily CO_2 mass emissions from sorbent (in tons).

* * * * *

(Eq. G–7) * * *

%R = Overall percentage SO_2 emissions removal efficiency, calculated using equations such as those in EPA Method 19 in appendix A to part 60 of this chapter, and using daily instead of annual average emission rates.

* * * * *

Appendix G to Part 75 [Amended]

69. Appendix G to Part 75 is amended by:

a. Removing and reserving sections 5.1 and 5.1.1;

b. Revising 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

* * * * *

5.1 [Reserved]

5.1.1 [Reserved]

* * * * *

5.2 Missing Carbon Content Data

Use the following procedures 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
	Subbituminous/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

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PART 75—[AMENDED]

70. In part 75, revise all references to "low mass emission unit" to read "low mass emissions unit".

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