ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72 and 75

[FRL–6320–8]

RIN 2060–AG46

Acid Rain Program; Continuous Emission Monitoring Rule Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Title IV of the Clean Air Act (CAA or the Act), as amended by the Clean Air Act Amendments of 1990, authorizes the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. The Acid Rain Program and the provisions in this final rule benefit the environment by ensuring that the sulfur dioxide (SO_2), nitrogen oxides (NO_X) and carbon dioxide (CO_2) air pollution emissions to be measured and tracked pursuant to the provisions of 40 CFR part 75 are accurately monitored and reported. These provisions also benefit the regulated entities by providing additional flexibility and improved cost effectiveness to the monitoring and reporting options available to part 75 subject sources. On January 11, 1993, the Agency promulgated final rules, including the final continuous emission monitoring (CEM) rule, under title IV. On May 17, 1995 and November 20, 1996, the Agency revised the CEM rule to make the implementation simpler. On May 21, 1998, the Agency proposed additional revisions to the CEM rule, to make implementation easier and more efficient for both EPA and the facilities affected by the rule, to improve quality assurance requirements, and to create new alternative monitoring options. EPA promulgated final rule revisions addressing some of these additional proposed revisions, based on comments received, when EPA promulgated a Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone (NO_X SIP call).

In this action, EPA is issuing final rule revisions addressing the remaining May 21, 1998 proposed revisions to the CEM rule, with certain changes to the proposal based on the public comments received. Some of these revisions will be relevant for sources that become subject to part 75 requirements in response to the NO_X SIP call.

DATES: The effective date of this rule is June 25, 1999. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of June 25, 1999.

ADDRESSES: *Docket.* Supporting information used in developing the regulations is contained in Docket No. A–97–35. 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.

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SUPPLEMENTARY INFORMATION: The contents of the preamble are listed in the following outline:

I. Regulated Entities

Entities regulated by this action are fossil fuel-fired boilers and turbines that serve generators producing electricity, generate steam, or cogenerate electricity and steam. While part 75 primarily regulates the electric utility industry, the recent promulgation of 40 CFR part 96 and certain revisions to part 75 (see 63 FR 57356, October 27, 1998) means that part 75 could potentially affect other industries. The recent adoption of part 96, together with revisions to part 75, include nitrogen oxides (NO_X) mass provisions for the purpose of serving as a model which could be adopted by a state, tribal, or federal NO_X mass reduction program covering the electric utility and other industries. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Electric service providers, boilers, turbines and other process sources where emissions exhaust through a stack.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities which EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should carefully examine the applicability provisions in §§ 72.6, 72.7, 72.8, and part 96 of title 40 of the Code of Federal Regulations. 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

Title IV of the Act requires EPA to establish an Acid Rain Program to reduce the adverse effects of acidic deposition. On January 11, 1993, the

Agency promulgated final rules implementing the program, including the CEM rule (58 FR 3590). Notices of direct final rulemaking and of interim final rulemaking further amending the regulations were published on May 17, 1995 (60 FR 26510 and 60 FR 26560). Subsequently, on November 20, 1996, a final rule was published in response to public comments received on the direct final and interim rules (61 FR 59142). On May 21, 1998, the Agency published proposed revisions to the part 75 CEM regulations (62 FR 28032). As noted above, EPA recently promulgated final revisions to part 75 addressing some of the May 21, 1998, proposed revisions in conjunction with the promulgation of a Model NO_X Trading Rule in part 96 and the NO_X SIP call (see 63 FR 57356).

Today's action adopts final part 75 revisions to address the remaining May 21, 1998, proposed revisions and to make minor technical corrections to the part 75 provisions promulgated in conjunction with part 96 and the NO_X SIP Call. The final revisions involve the following matters: (1) revised definitions of gas-fired, oil-fired, and peaking unit to allow for changes in unit fuel usage and/or operation; (2) a minor wording correction to the applicability provisions in part 72; (3) new quality assurance/quality control (QA/QC) requirements for quantifying stack gas moisture content; (4) clarifying changes to the certification and recertification process; (5) substitute data requirements for carbon dioxide (CO_2), heat input and moisture; (6) clarifying revisions to the petition provisions for alternatives to part 75 requirements; (7) clarifying changes to span and range requirements; (8) clarifying revisions to general QA/QC requirements; (9) calibration error test requirements; (10) linearity test requirements; (11) a new flow-to-load QA test for flow monitors; (12) reductions in and/or clarifications to the relative accuracy test audit (RATA) and bias test requirements; (13) clarifying revisions to the procedures for CEM data validation; (14) clarifying revisions to the sulfur dioxide (SO_2) emissions data protocol for gas-fired and oil-fired units (Appendix D); (15) determination of CO_2 emissions under Appendix G; (16) recordkeeping and reporting changes to reflect the proposed revisions; (17) a revised traceability protocol for calibration gases (Appendix H); and (18) NO_X mass emission recordkeeping and reporting provisions, and minor revisions to NO_X mass monitoring requirements.

Many of these changes are minor technical revisions based on comments received from facilities following the initial implementation of part 75. Based on experience gained in the early years of the program, facilities have developed a number of suggestions that will simplify and streamline the monitoring process without sacrificing data quality. The Agency has also amended quality assurance requirements based on gaps identified by EPA during evaluation of the initial implementation of part 75. Finally, several minor technical changes have been made in order to maintain uniformity within the rule itself and to clarify various provisions.

III. Summary of Major Comments and Responses

A. Certification/Recertification Procedural Changes

Background: EPA proposed to revise the recertification application review period in § 75.20(b)(5) from 60 days to 120 days, which is the same review period as for the initial certification application. The Agency believes that this will reduce confusion, simplify certification/recertification application tracking, and will result in the more efficient allocation of resources by local, state, and federal agencies. Therefore, EPA has adopted this change in the final rule with certain modifications in response to issues raised by commenters.

Discussion: Two states responded positively to the proposed change. One state commented that the increased review time ''will allow more effective use of staff resources and provide ample time for a thorough review of the data submitted in the application'' (see Docket A–97–35, Item IV–D–6). Another state commenter remarked that extending the review period ''adds uniformity and consistency to the certification and recertification process. This change is positive, and it allows the state agencies the time to resolve minor deficiencies which may otherwise serve as grounds to recommend disapproval. Based on experience, the 120 day period is absolutely essential for the review of certification/recertification applications'' (see Docket A–97–35, Item IV–D–9).

Several commenters suggested that if EPA disapproved a recertification application after the 120 day period, data recorded during the entire 120 day period would become invalid and the use of substitute data would be required (see Docket A–97–35, Items IV–D–17, IV–D–20 and IV–D–24). However, as EPA stated in the preamble to the proposal, ''less than 2 percent of all monitoring system applications submitted between 1992 and September 1997 were disapproved'' (63 FR 28045, citing Docket A–97–35, Item II–A–4). As experience with the program increases, the number of disapprovals is expected to decrease even further. In addition, EPA's position is that the owners or operators of affected facilities are responsible for initiating, conducting, evaluating and certifying the results of the required testing prior to submission to the appropriate regulatory Agencies. The Agencies' role is to ''certify'' or verify the results. Thus, there is no reason to expect that the additional time provided to meet the administrative needs of the program will result in any significant compliance risk to the regulated sources, except in instances where insufficient care is taken to ensure proper conduct of the testing.

Two commenters stated that the owner or operator would be in violation of the requirements of proposed § 75.33(d) and § 75.10(a) if a recertification application were disapproved after 120 days (see Docket A–97–35, Items IV–D17 and IV–D–23) because the percent monitor availability would be below 80%. These proposed penalties have been withdrawn from the final rule in response to comments received. Today's final rule does not treat a percent monitor data availability of less than 80% as a violation. Instead, the final rule provides that if percent monitor data availability is less than 80%, then the appropriate maximum value (e.g., maximum potential concentration) or, in some cases, the appropriate minimum potential value will be used to provide substitute data (see Section C of this preamble for a further discussion of these provisions).

Several commenters suggested that since the review of the initial certification applications for the Acid Rain Phase I and Phase II units has been completed, the burden on the states and EPA has been removed . Therefore, it should not take EPA 120 days to review recertification applications (see Docket A–97–35, Items IV–D–14, IV–D–20, and IV–D–24). This argument would be more compelling if the Acid Rain Program were the only program that the various regulatory agencies are required to implement. However, EPA and the States are currently responsible for implementing several other programs that require comprehensive administrative review of various types of applications and petitions (e.g., Compliance Assurance Monitoring (CAM), the OTC NO_X Budget Program, the PSD program and Title V permitting). EPA also anticipates that the NO_X SIP call will further increase the number of certification and recertification applications and petitions that need to be reviewed by the regulatory agencies.

Many recertifications require the same tests as for initial certification. Therefore, recertification applications often take as much effort to review as certification applications. It is also sometimes difficult to distinguish a recertification application package from an initial certification application package, which can complicate tracking the two types of applications if they have different review periods. The recertification process usually requires that a state or local program perform the initial review and forward the results to the EPA regional office which will then make a recommendation to EPA headquarters on whether to approve or disapprove the application. This requires a significant amount of time and does not allow much time to coordinate with the source to get additional information, when needed. There is more likelihood of a disapproval being issued under a short time frame. Finally, EPA notes that it does not have control over the number of recertification applications that are submitted. Individual utility choices, changes in rules, market conditions, and technology all influence the number of recertifications. Therefore, EPA has concluded that extending the application review period from 60 to 120 days is both necessary and appropriate.

B. Quality Assurance Requirements for Quantifying Stack Gas Moisture Content

Background: Section 75.11(b) of the January 11, 1993 Acid Rain rule requires the owner or operator to continuously (or on an hourly basis) account for the moisture content of the stack gas when SO_2 concentration is measured on a dry basis. The moisture content is needed to correct the measured hourly stack gas volumetric flow rates to a dry basis when calculating SO_2 mass emission rates in lb/hr. Section 75.13(a) of the rule, as amended on May 17, 1995, contains provisions for CO_2 monitoring paralleling the provisions of § 75.11(b); that is, when CO_2 concentration is measured on a dry basis, a correction for stack gas moisture content is needed to accurately determine the CO_2 mass emissions. The stack gas moisture content is also needed when a dry-basis O_2 monitor is used to account for CO_2 emissions and, in some instances, when accounting for unit heat input or when determining NO_X emission rate in lb/mmBtu.

As presently codified, part 75 does not specify any quality assurance requirements for moisture measurement devices. Approximately 5 to 10 percent of the continuous emission monitors in the Acid Rain Program require moisture corrections to accurately measure SO_2, CO_2, or NO_X emissions or heat input (see Docket A–97–35, Item II–I–6). The accuracy of the stack gas moisture measurements directly affects the accuracy of the reported SO_2 mass emission rates, CO_2 mass emission rates, NO_X emission rates and heat input values. An error of 1.0 percent H_2O in measured moisture content causes a 1.0 percent error in the reported emission rate or heat input value. Failure to quality assure the moisture data can therefore result in significant under-reporting of SO_2, CO_2, and NO_X emissions and heat input.

In the May 21, 1998 proposed rule, EPA set forth quality assurance procedures that would apply to moisture monitoring systems because the Agency believes that when moisture corrections must be applied, continuous, quality assured, direct measurement of the stack gas moisture content or continuous measurement of surrogate parameters for moisture, such as wet-and dry-basis oxygen concentrations, is the best way to ensure the accuracy of the reported emission data. The proposed rule specified that a moisture monitoring system could consist of either: (1) a continuous moisture sensor; (2) an oxygen (O_2) analyzer (or analyzers) capable of measuring O_2 on both a wet basis and on a dry basis; or (3) a system consisting of a temperature sensor and a certified data acquisition and handling system (DAHS) component capable of determining moisture from a lookup table, i.e., a psychometric chart (this third option would apply only to saturated gas streams following wet scrubbers).

The proposed rule included requirements for the initial certification of moisture monitoring systems. For continuous moisture sensors, a 7-day calibration error test and a relative accuracy test audit (RATA) would be required. For moisture monitoring systems consisting of one or more wet- and dry-basis oxygen analyzers, the proposed requirements included a 7-day calibration error test, a linearity test and a cycle time test of each O_2 analyzer, and a RATA of the moisture measurement system. For the lookup table option (saturated streams, only), the certification requirement would consist of a DAHS verification. The proposed rule specified that owners or operators would have to complete all moisture monitoring system certification tests no later than January 1, 2000.

The proposed rule contained performance specifications for moisture monitoring systems. These specifications would apply to continuous moisture sensors and to wet- and dry-basis oxygen analyzers. For moisture monitoring systems consisting of wet-and dry-basis O_2 analyzers, the proposed span values and performance specifications for calibration error, linearity, and cycle time would be the same as the current specifications for O_2 monitors. For moisture sensors, a calibration error specification of 3.0% of span was proposed. The proposed relative accuracy (RA) specification for all moisture monitoring systems would be 10.0 percent. An alternative RA specification was also proposed, i.e., the RA test results would be considered acceptable if the mean difference of the reference method measurements and the moisture monitoring system measurements is within $\pm$ 1.0 percent H_2O.

On-going QA requirements for moisture monitoring systems were also proposed. Appendix B would be revised to require daily calibrations of moisture monitoring systems, quarterly linearity checks of wet-and dry-basis oxygen analyzer(s), and semiannual RATAs of moisture monitoring systems. Any moisture monitoring system achieving a relative accuracy of $\leq$7.5 percent or a mean difference between the CEMS and reference method values within $\pm$ 0.7 percent H_2O, would qualify for an annual, rather than semiannual RATA frequency.

Missing data procedures for moisture were included in the proposed rule in a new section, § 75.37. Provided that the moisture data availability is high ($\geq$90.0 percent), the average of the ''hour before'' and ''hour after'' moisture values would be used for each hour of the missing data period. When the percent data availability drops below 90.0 percent, 0.0 percent moisture would be substituted for each hour of the missing data period.

Finally, the proposed rule specified that records must be kept for the moisture monitoring systems, including hourly average moisture readings, percent data availability, and records of all calibration error tests, linearity tests and relative accuracy test audits.

Today's final rule provides a number of options by which owners or operators of affected sources may account for the stack gas moisture content on an hourly basis. The rule also includes quality assurance provisions for moisture monitoring systems. Today's rule differs from the proposed rule as follows: (1) the alternate specification in terms of the mean difference has been increased from ± 1.0 to ± 1.5% H_2O, but the principal relative accuracy specification for moisture monitoring systems has been promulgated as proposed, at 10.0 percent; (2) the daily calibration requirement for continuous moisture sensors has been withdrawn; (3) the use of the lookup table option has been expanded to include any demonstrably saturated gas stream, rather than limiting it to gas streams following wet scrubbers; (4) a site-specific coefficient or constant (''K'' factor), determined at the time of the RATA, may be used to calibrate the moisture monitoring system with respect to EPA Reference Method 4; and (5) in lieu of continuously monitoring the stack gas moisture content, a conservative, fuel-specific default moisture percentage may be reported for each unit operating hour (for coal and wood, only).

Discussion: Two state agencies agreed with EPA that there is a need for quality assurance of moisture monitoring systems (see Docket A–97–35, Items IV–D–06 and IV–D–09). A third state agency disagreed with the proposed QA/QC for the moisture monitors, contending that the proposed amendments provide no added benefit in terms of data quality (see Docket A–97–35, Item IV–D–11). That same state agency objected to quality assuring a ''sub-channel'' parameter such as moisture, claiming that it is inconsistent with the way EPA quality assures other combined monitoring systems (such as a NO_X-diluent system). The commenter expressed confidence that existing daily, quarterly, semiannual and annual QA/QC on the gas and flow rate monitors is sufficient to ensure data quality, and that if the CEMS moisture value is significantly in error, RATA limits would probably not be met. EPA notes, however, that the commenter provided no data to demonstrate that this is true. The Agency also does not agree with the commenter's characterization of moisture as a ''sub-channel'' parameter. The attempt to draw an analogy between moisture monitoring and the NO_X-diluent monitoring system is inappropriate. Under part 75, the moisture measurement system is a separate entity and should be quality-assured as such. The moisture monitor is not a component of any ''combined'' monitoring system. The only true combined monitoring systems under part 75 are the NO_X-diluent and SO_2-diluent monitoring systems, for which the relative accuracy is determined on a combined basis, in lb/mmBtu (i.e., the individual relative accuracies of the pollutant and diluent component monitors are not determined).

Several commenters indicated that they do not believe that a moisture monitoring system can meet the proposed relative accuracy (RA) specifications of 10.0% for a semiannual RATA frequency or 7.5% for an annual RATA frequency. One commenter expressed the opinion that the RA for a moisture monitoring system should be 15.0% (see Docket A–97–35, Item IV–G–04). Another commenter suggested that the principal RA specification should be 10% <RA ≤15% for a semiannual RATA frequency and RA ≤10% for an annual RATA frequency, and that the alternate RA specification, in terms of the mean difference, should be ± 2.0% H_2O for a semiannual frequency and ± 1.5% for an annual RATA frequency (see Docket A–97–35, Item IV–D–23). Another commenter noted that even slight drift in measurements can result in significant errors in the moisture measurements (see Docket A–97–35, Item IV–D–20). One commenter requested that EPA consider the following alternatives to the proposed QA/QC requirements for moisture monitors: (1) eliminate the moisture RA requirement; (2) for wet and dry oxygen analyzers, allow relative accuracy testing of the oxygen analyzer(s) rather than requiring a RATA of the moisture system; (3) allow the use of a default value for moisture, in lieu of monitoring moisture continuously; or (4) subtract the absolute value of the average moisture values generated by the moisture monitoring system from the average reference method value at the time of a RATA and use the difference to correct all subsequent moisture data until the next RATA (see Docket A–97–35, Item IV–D–02).

Only one set of data was submitted by the commenters for a moisture monitoring system RATA. The data set indicated that the moisture monitoring system, which consisted of wet and dry-basis oxygen analyzers, could achieve an RA of 16.5% (see Docket A–97–35, Item, IV–D–02). Note, however, that when the moisture monitoring system data and the reference method data were compared, the moisture monitoring system consistently indicated a moisture value that was approximately 3% H_2O higher than the reference method, with a confidence coefficient of 0.507. The low confidence coefficient indicates that the moisture monitoring system readings were consistently biased high with respect to the reference method. Therefore, it appears that a suitable coefficient or constant (''K'' factor) could be applied to the moisture system readings, to make the moisture monitoring system readings agree with the reference method. In this case, subtracting 3% moisture from the average moisture monitoring system values for each run caused the relative accuracy to drop from 16.5% to 2.4%, which is well below the proposed 10.0% semiannual and 7.5% annual RA specifications. For the alternate RA specification, after applying the 3% moisture correction, the mean difference was essentially zero, which is also well below the value of 1.0% moisture proposed for a semiannual RATA frequency and the value of 0.7% moisture proposed for an annual RATA frequency. This ''K'' factor approach, which was suggested by one of the commenters, has a precedent in the Acid Rain Program. Nearly all flow monitors must be calibrated to match the EPA reference method (i.e., Method 2), by using either a constant or a polynomial equation with multiple coefficients. Section 6.5.7 of Appendix A of today's rule allows such ''K'' factors to be developed for moisture monitoring systems. The ''K'' value, which would be established at the time of the semiannual or annual RATA, would be programmed into the DAHS and applied to the subsequent moisture data. Sections 75.56 (a)(5)(ix) and 75.59 (a)(5)(vii) of today's rule require the owner or operator to keep records on-site, indicating the current value of the coefficient or ''K'' factor and the date on which it began to be used. The rule further requires a RATA of the moisture monitoring system whenever the coefficient or ''K'' factor is changed.

Relative accuracy specifications of 10.0% (for semiannual RATA frequency) and 7.5% (for annual RATA frequency) for moisture monitoring systems have been promulgated in today's rule, as proposed. The alternate RA specifications of ± 1.0% H_2O (for semiannual RATA frequency) and ± 0.7% H_2O (for annual RATA frequency) have been increased, respectively, to ± 1.5% H_2O and ±1.0% H_2O. In view of EPA's decision to allow the use of site-specific ''K'' factors for moisture monitoring systems, the Agency believes that affected utilities will be able to meet these RA specifications.

The proposed rule set forth a missing data procedure for moisture monitoring systems. Two commenters expressed concern regarding the establishment of such a ''conservative'' missing data procedure (see Docket A–97–35, Items IV–D–11 and IV–D–20). One of these commenters further stated that there are insufficient data to know what availability can reasonably be expected from moisture monitoring systems, especially in view of the proposed moisture QA/QC specifications. After careful consideration, the Agency agrees with the commenter and, in response, the final rule adopts the missing data procedures in § 75.37 that are less conservative than the procedures in the proposed rule and that more closely resemble the standard missing data procedures for SO_2, NO_X, and flow, as recommended by the commenters. The moisture missing data algorithm is modeled after the standard SO_2 missing data algorithm in § 75.33(b). This is consistent with the provisions in §§ 75.35 and 75.36 of today's rule, which adopt this algorithm for CO_2 and heat input missing data. However, in finalizing the moisture missing data provisions, it became evident that a single mathematical algorithm is not adequate to cover all of the part 75 emission rate and heat input equations that require moisture corrections. In most of the equations, the lower moisture values are more conservative, and an ''inverted'' SO_2 missing data algorithm is appropriate (for further discussion of the ''inverted'' algorithm, see section C of this preamble, below). However, there are certain emission rate equations for which the opposite is true (i.e., the higher moisture values are more conservative and the regular SO_2 missing data algorithm is appropriate). The specific equations for which the regular SO_2 algorithm applies are Equations F–3, F–4 and F–8 in Method 19 in Appendix A of 40 CFR 60. Provided that all of the moisture-corrected emission and heat input equations used by an affected facility employ the same moisture missing data algorithm (regular or inverted), it is a simple matter to substitute for missing moisture data. However, when two or more equations require different moisture algorithms, an alternative way of addressing missing moisture data is needed. EPA believes that this situation will rarely be encountered (at present, the Agency's records indicate that there are only two such affected units in the Acid Rain Program). Therefore, § 75.37(d) of today's rule requires the owner or operator of such units to petition the Administrator under § 75.66(l), for an alternative moisture missing data procedure.

Finally, several commenters requested that EPA allow the use of a default moisture value in lieu of the required moisture monitoring (see Docket A–97–35, Items IV–D–11, IV–D–02 and IV–D–23). The Agency has performed a moisture data analysis for various fuels (see Docket A–97–35, Item IV–A–2) and, based on the results, has provided fuel-specific default values for moisture in today's rule (for coal and wood, only), which may be reported for each unit operating hour, as an alternative to operating and maintaining a continuous moisture monitoring system. The default values are found in §§ 75.11(b)(1) and 75.12(b) of today's rule. Note that two sets of default values appear in the rule to address the variability in format among the equations used for determining pollutant emissions and heat input (as discussed in the previous paragraph). The lower default values in § 75.11(b)(1) apply to Equations F–2, F–14b, F–16, F–17 and F–18 in Appendix F of part 75 and to Equations 19–5 and 19–9 in EPA Method 19 in Appendix A of 40 CFR 60. The higher default values in § 75.12(b) apply when Equation 19–3, 19–4 or 19–8 in EPA Method 19 in Appendix A of 40 CFR 60 is used to determine the NO_X emission rate. The default values were determined as follows. The moisture percentage values (which included both ultimate moisture and free moisture) for each fuel type were taken from the appropriate tables in Docket Item IV–A–2, cited above. The moisture values were then ranked from the lowest percentage value to the highest percentage value, and the 10th percentile value was selected for the ''low'' default value and the 90th percentile value was selected for the ''high'' default value. Each default moisture percentage was rounded to the nearest whole number.

C. Percent Monitor Availability

Background: EPA proposed that if the annual monitor data availability dropped below 80% for SO_2, NO_X, flow rate or CO_2, this would violate the primary measurement requirement of § 75.10(a). In response to comments, today's final rule does not treat a percent monitor data availability of less than 80% as a violation. Instead, the final rule provides that if percent monitor data availability is less than 80%, then the appropriate maximum value (i.e., maximum potential concentration (MPC) for SO_2 and CO_2, maximum potential emission rate (MER) for NO_X and maximum potential flow rate for flow) will have to be used as substitute data for any hour for which valid data is not available. For O_2, the minimum potential concentration will be used to provide substitute data. For moisture, consistent with the discussion in section B of this preamble, the minimum potential moisture percentage will be used in most instances to provide substitute data; however, for certain emission rate equations, the maximum potential moisture percentage must be used.

Discussion: EPA received one comment that supported making a percent monitor availability of less than 80% a violation (see Docket A–97–35, Item IV–D–11) and another commenter favored the provision that if percent monitor availability is below 80% due to ''unforseen events beyond our control,'' this would be taken into consideration (see Docket A–97–35, Item IV–G–9). EPA also received comments objecting to making a percent monitor data availability of less than 80% a violation and suggesting that EPA should modify the standard missing data algorithms for SO_2, NO_X and flow rate to require the use of a maximum substitute data value when monitor availability drops below 80 percent (see Docket A–97–35, Items IV–D–17, IV–D–19, IV–D–23, IV–D–24). In response to the comments, the final rule does not make percent monitor availability of less than 80% a violation and instead provides that if percent monitor data availability at a source is less than 80%, then the owner or operator of the source will have to substitute the appropriate maximum value (i.e., MPC for SO_2 and CO_2, MER for NO_X emission rate and maximum potential flow rate for flow) as suggested by the commenters. Note that for O_2 and, in most cases, for moisture, minimum potential values will be substituted rather than maximum values, since the lower values of these parameters are more conservative. However, if Equation 19–3, 19–4 or 19–8 in EPA Method 19 in Appendix A of 40 CFR 60 is used to determine NO_X emission rate, higher moisture values are more conservative and the maximum potential moisture percentage will be used to provide substitute data.

The missing data approach set forth in today's rule to address low monitor data availability retains the basic design of the part 75 program and appropriately addresses the need for accountability from sources that are inadequately maintaining their monitoring systems. The Agency maintains that this provides a strong incentive to achieve at least 80% monitor availability. Unlike the proposed approach of considering sources to be in violation, the substitute data approach adopted today creates this incentive while rendering unnecessary the task of determining and evaluating the reason(s) for low monitor data availability.

D. Span and Range Requirements

Background: The span of a CEMS provides an estimate of the highest expected value for the parameter being measured by the CEMS. For instance, the span value of an SO_2 monitor is an approximation of the highest SO_2 concentration likely to be recorded by the CEMS during operation of the affected unit. The range of a CEMS is the full-scale setting of the instrument. Under part 75, the range of a monitor must be equal to or greater than the span value. Section 2.1 of Appendix A further specifies that the range must be chosen such that the majority of the readings during normal operation fall between 25.0 and 75.0 percent of full-scale. The span value is important because the reference gas concentrations and signals used for daily calibration of the CEMS are expressed as percentages of the span value. The allowable daily calibration error for a CEMS is also expressed as a percentage of span.

Sections 2.1.1 through 2.1.4 of Appendix A of the January 11, 1993 rule specified procedures for determining the span values for SO_2, NO_X, diluent gas (O_2 or CO_2), and volumetric flow rate. For SO_2, the ''maximum potential concentration'' (MPC) was first calculated based on fuel sampling. The MPC values for NO_X were specified in the rule and were based on the type of fuel being combusted. The SO_2 and NO_X span values were then determined by multiplying the MPC by 1.25. For CO_2 and O_2, a span value of 20.0 percent CO_2 or O_2 was required for all diluent monitors. For flow rate, the ''maximum potential velocity'' (MPV) was first determined. Then, the span value was obtained by multiplying the MPV by 1.25 and rounding off the result.

In the January 11, 1993 rule, the SO_2 or NO_X monitor range derived from the MPC was referred to as the ''high-scale.'' The rule further specified that whenever the majority of the readings during normal operation were expected to be less than 25.0 percent of the high full-scale range value (e.g., if a scrubber is used to reduce SO_2 emissions), a second, ''low-scale'' span and range would be required. The low scale span value of the CEMS would be defined as 1.25 times the ''maximum expected concentration'' (MEC).

In the first two years of Acid Rain Program implementation, it became clear that the span and range provisions of part 75 lacked sufficient flexibility and clarity. The May 17, 1995 rule revisions attempted to address these deficiencies. Two alternative methods of determining the MPC or MEC were added, i.e., from historical CEMS data or from emission test results. For NO_X, a comprehensive list of MPC values was promulgated (Tables 2–1 and 2–2 in Appendix A), taking into consideration the unit type in addition to the fuel type. Flexibility was also added to the dual-range requirements for NO_X monitors. For flow rate, a more detailed procedure for determining the span value was added.

The May 17, 1995 rule also revised the procedures for adjusting the span and range of SO_2, NO_X, and flow monitors. The original rule had specified that span and range adjustments were required whenever the MPC, the MEC, or the MPV changed significantly (although a ''significant'' change was undefined). When a significant change in the MPC, MEC, or MPV occurred, a new range setting was to be established and a new span value defined, equal to 80.0 percent of the adjusted range value. The May 17, 1995 rule changed this procedure, requiring the new span value to be determined first, followed by the new range. The May 17, 1995 rule also added procedures for addressing full-scale exceedances, specifying that the full-scale value is to be reported for an exceedance of one hour and that a range adjustment is required for an exceedance greater than one hour.

After promulgation of the May 17, 1995 rule, EPA continued to receive questions and comments about the span and range sections of part 75. Apparently, the span and range sections of the rule were still not sufficiently clear, flexible, or detailed and were in need of further revision. Therefore, on May 21, 1998, further revisions to the span and range provisions were proposed.

The proposed rule provided an alternative procedure for determining the MPC of SO_2 or NO_X, requiring the MPC to be based upon a minimum of 720 quality assured monitor operating hours, rather than 30 unit operating days. A specific requirement to calculate the maximum potential NO_X emission rate (MER) was also proposed. The owner or operator could use the diluent cap value of 5.0 percent CO_2 or 14.0 percent O_2 for boilers (or 1.0 percent CO_2 or 19.0 percent O_2 for turbines) in the NO_X MER calculation.

The proposed rule provided a definition of the MPC for CO_2. The MPC would be 14.0 percent CO_2 for boilers and 6.0 percent CO_2 for combustion turbines. Alternatively, the MPC for CO_2 could be based on a minimum of 720 hours of representative quality assured historical CEM data. A standardized procedure for calculating the maximum potential flow rate (MPF) was proposed and a clear distinction between the ''calibration span value'' of a flow monitor (expressed in the units of measure used for the daily calibrations) and the ''flow rate span value'' (expressed in the units used for electronic data reporting) was provided.

The proposed rule set forth changes to the procedures for determining the maximum expected concentration (MEC) of SO_2 and NO_X, and to the criteria for determining whether dual span and range requirements apply. A separate MEC determination would be required for each type of fuel combusted, except for fuels that are only used for unit startup or for flame stabilization. To determine whether a second, low-scale span is required in addition to the high-scale span based on the MPC, each of the maximum expected concentration (MEC) values would be compared against the MPC. If any of the MEC values was <20.0 percent of the MPC, a low-scale span would be required.

The proposed rule provided additional flexibility in the method of calculating span values. The SO_2, NO_X or flow rate span value could be set anywhere between 1.00 and 1.25 times the applicable maximum value (i.e., the MPC, MEC or MPF). For CO_2 and O_2 monitors, the owner or operator would be given maximum flexibility in selecting an appropriate span value. For CO_2 monitors installed on boilers, any representative span value between 14.0 percent and 20.0 percent CO_2 would be acceptable. For combustion turbines, any representative CO_2 span value between 6.0 and 14.0 percent CO_2 could be used. For O_2 monitors, a span value between 15.0 percent and 25.0 percent O_2 could be selected and an alternative O_2 span value of less than 15.0 percent could be used, if supported by an acceptable technical justification.

The proposed rule expanded and clarified the guideline in section 2.1 of Appendix A for selecting an appropriate full-scale range. The full-scale range would be selected so that the readings during typical unit operation fall between 20.0 and 80.0 percent of full-scale, which represents a slight increase in flexibility from the 25 to 75 percent of full-scale guideline in the current rule. The proposal also cited three specific cases in which the guideline in section 2.1 is inapplicable: (1) during the combustion of very low sulfur fuels (≤0.05% sulfur by weight); (2) for SO_2 or NO_X readings on the high range for an affected unit with SO_2 or NO_X emission controls and two span values; and (3) when SO_2 or NO_X readings are less than 20.0 percent of the low measurement range for a dual-span unit with SO_2 or NO_X emission controls, provided that the low readings occur during periods of high control device efficiency.

The proposed rule specified that the following monitoring configurations could be used to meet dual span and range requirements: (1) a single analyzer with two ranges, or (2) two separate analyzers connected to a common probe and sample interface. The high and low ranges could be designated in the monitoring plan as two separate, primary monitoring systems, or as separate components of a single, primary monitoring system, or the ''normal'' range could be designated as a primary monitoring system, and the other range as a non-redundant backup monitoring system.

The proposed rule would allow the owner or operator to use a ''default high-range value'' in lieu of operating, maintaining, and quality assuring a high-scale monitor range. The default high-range value would be 200.0 percent of the MPC. This value would be reported whenever the SO_2 or NO_X concentration exceeded the full-scale of the low-range analyzer.

Finally, the proposed rule provided detailed guidelines and procedures for adjusting the span and range of the CEMS. First, if the maximum value upon which the high span value is based (i.e., the MPC or MPF) was exceeded during a calendar quarter, but the span was not exceeded, the span or range would not have to be adjusted. However, if any quality assured hourly concentration or flow rate exceeded the MPC or MPF by ≥5.0 percent during the quarter, a new MPC or MPF would have to be defined. Second, if any quality assured reading on the high measurement range exceeded the span value by ≥10.0 percent during the quarter but did not exceed the range, a new MPC or MPF (as applicable) would have to be defined, and the span value (and range, if necessary) would also have to be changed. Third, for full-scale exceedances of a high monitor range, corrective action would be required to adjust the span and range. A value of 200.0 percent of the current full-scale range would be reported to EPA for each hour of each full-scale exceedance.

Today's rule finalizes the proposed revisions to the span and range sections of Appendix A. Most of the provisions have been finalized as proposed, with only minor changes and clarifications. However, there are three notable exceptions: (1) the proposed requirement for mandatory quarterly evaluations of the MPC, MEC and MPF values and the associated prescriptive criteria for adjusting the spans and ranges have been withdrawn; (2) the proposed change in methodology for determining dual span and range requirements (i.e., comparing the MEC value(s) to the MPC) has been withdrawn; and (3) an additional monitoring configuration option has been provided for units with dual span requirements. For units with a dual-range SO_2 or NO_X analyzer, the final rule allows the low and high ranges to be represented as a single component of a primary SO_2 or NO_X monitoring system.

Discussion: EPA received supportive comments from a number of utilities, regarding several of the proposed span and range revisions (see Docket A–97–35, Items IV–D–20, IV–D–23, IV–D–24, IV–D–25, and IV–G–01). The commenters generally favored the increased flexibility in determining SO_2, NO_X, CO_2 and O_2 span values and supported the concept of a ''default high range value.'' One commenter, however, opposed the use of purified instrument air for O_2 monitor calibrations (see Docket A–97–35, Item IV–D–11) and, as discussed in greater detail below, two commenters who supported the ''default high range'' concept took issue with the proposed default value (see Docket A–97–35, Items IV–D–05 and IV–D–24). One commenter asked EPA to give guidance as to what type of technical justification would be required to use an alternative O_2 span value of less than 15 percent (see Docket A–97–35, Item IV–D–23). The final rule provides an example, in section 2.3.1 of Appendix A.

Several commenters stated that the proposed procedures for making span and range adjustments were particularly complicated and burdensome (see Docket A–97–35, Items IV–D–19, IV–D–20, IV–D–23, IV–D–24 and IV–G–09). Two commenters stated that the requirement to perform quarterly evaluations of the MPC, MEC and MPF values is unnecessary and excessive (see Docket A–97–35, Items IV–D–11 and IV–G–02). One commenter recommended using the guideline in section 2.1 of Appendix A to determine whether span and range adjustments are needed (see Docket A–97–35, Item IV–D–11). Another commenter recommended that EPA allow data points that are clear ''outliers'' to be excluded from quarterly span and range evaluations (see Docket A–97–35, Item IV–D–04). After carefully considering these comments, EPA has decided to withdraw the prescriptive proposed procedures for making span and range adjustments. Instead, the final rule requires that span and range adjustments be made only when the MPC, MEC or MPF changes ''significantly.'' This is similar to the original guideline in the January 11, 1993 rule, except that a ''significant'' change was undefined in that rule. In today's rule, a significant change in the MPC, MEC or MPF means that the guideline of section 2.1 of Appendix A (for the majority of the readings to be between 20 and 80% of the range, with certain allowable exceptions) cannot be met, as determined either by the owner or operator or through an audit by a regulatory agency. The Agency has also reduced the frequency of mandatory evaluations of the MPC, MEC and MPF values. In the final rule, only an annual evaluation of these values is required. The results of the annual evaluations must be kept on-site, in a format suitable for inspection.

Two commenters stated that the proposed requirement to treat the two ranges of a dual-range monitor as separate monitoring systems or as two separate components of the same system would cause additional programming costs and would be technically difficult to implement (see Docket A–97–35, Items IV–D–4 and IV–G–02). The commenters requested that EPA continue to allow the low and high ranges to be represented in the monitoring plan by a single component. After consideration, the Agency has decided that the commenters' request is reasonable and has included this option in the final rule. Note, however, that the use of this option is restricted to dual-range analyzers that use electronic gain to produce the two ranges. Today's rule requires the use of a special dual-range component type code when this option is selected. EPA will provide the necessary type code and reporting guidance in the electronic data reporting (EDR) instructions for EDR version 2.1.

Two commenters stated that 200% of MPC is too high for the proposed default high range value in sections 2.1.1.3(f) and 2.1.1.4(e) of Appendix A, for the case where the owner or operator uses a default value instead of operating a high-range monitor (see Docket A–97–35, Items IV–D–05 and IV–D–24). A third commenter objected to the proposed value of 200% of the range, which is to be reported during full-scale exceedances (see Docket A–97–35, Item IV–G–05). Without a functional high range monitor, it is not possible to determine the exact pollutant concentration when a control device malfunctions or when a full-scale exceedance occurs. In the preamble to the proposed rule, EPA cited one instance in which the high SO_2 range was exceeded and the estimated SO_2 concentration (based on fuel sampling) was estimated to be about 150% of the range (see 63 FR 28058). For this reason, the proposed values of 200% of the range (for full-scale exceedances) and

200% of the MPC (for the default high range value) have been retained in the final rule. EPA maintains that these values must be conservative, based on a ''worst case'' analysis to ensure that emissions will not be under-reported. The Agency believes that if spans and ranges are properly set, full-scale exceedances will be relatively rare. Also, EPA anticipates that the majority of the units for which owners or operators will elect to use the default high range option have reliable emission controls and the default value will rarely, if ever, have to be used.

One commenter objected to the proposed changes to the method of calculating MPC and MEC values, expressing concern that the revisions might require his existing span and range values to be re-calculated (see Docket A–97–35, Item IV–G–02). Another commenter (mistakenly) interpreted the proposed definition of the MPC for CO_2 in section 2.3.1 of Appendix A to mean that his existing CO_2 span values would have to be re-determined (see Docket A–97–35, Item IV–D–04). A third commenter asked EPA to ''grandfather'' existing span and range values (see Docket A–97–35, Item IV–D–20). It is not, and never has been EPA's intent to require utilities to change their existing spans and ranges, provided that they meet the guideline of section 2.1 of Appendix A (for the majority of the readings to be between 20 and 80% of full-scale, with certain allowable exceptions). The Agency does not believe that ''grandfathering'' of any existing part 75 span and range values is necessary. The final rule simply adds flexibility to the procedures for determining spans and ranges. Affected units with previously-determined span and range values that meet the guideline of section 2.1 of Appendix A do not have to change their current span or range values. To further alleviate undue concern about this, the Agency has withdrawn the proposed changes to the method of determining whether a dual span is required. Rather than comparing the MEC value(s) to the MPC value(s) (as proposed), today's rule specifies that the MEC value should be compared to the high range value. This is essentially the same as the requirement in the current rule.

Finally, one commenter objected to the proposed requirement to perform the RATA at the low range of the monitor on units that have scrubbers. The commenter urged EPA to revert to the original rule and allow the RATA to be performed at whatever range the CEMS is operating on at the time of the RATA (see Docket A–97–35, Item IV–G–3). EPA does not agree with the commenter. For units with SO_2 scrubbers, the vast majority of the data is collected on the low range. Therefore, the SO_2 RATA should be performed on that range. If the scrubber malfunctions at the time of a scheduled SO_2 RATA, the RATA should either be rescheduled later in the quarter or should be done during the 720 unit operating hour grace period allowed under revised section 2.3.3 of Appendix B.

E. Flow-to-Load Ratio Test Requirements

Background: The quality assurance requirements for flow rate monitoring systems in Appendices A and B of part 75 include daily calibration error tests, daily interference checks, quarterly leak checks (for differential pressure type monitors only), and semiannual or annual RATAs. Of these required QA tests, only the RATA provides a true evaluation of a flow monitor's measurement accuracy by direct comparison against an independent reference method. The daily calibration error test checks the system's internal electronic components by means of reference signals. The calibration error test is useful in that it can diagnose certain types of monitor problems, but it does not evaluate the system's ability to measure an actual stack gas flow rate. Because of this limitation, EPA believes that a more substantive, periodic QA test is needed to ensure that the accuracy of the reported flow rate data is maintained in the interval between successive RATAs. The Agency is particularly concerned about the potential for poor data quality from flow monitors that are not properly maintained.

In view of this, EPA proposed to add a new flow monitor quality assurance test, the ''flow-to-load ratio test,'' to part 75 in section 7.7 of Appendix A and section 2.2.5 of Appendix B. A similar test was first suggested to the Agency by a flow monitor manufacturer (see Docket A–97–35, Item II–D–69). The flow-to-load ratio test, which would be performed quarterly, would be required beginning in the second quarter of the year 2000. The basic premise of the flow-to-load ratio test is that a meaningful correlation exists between the stack gas volumetric flow rate and unit load. In general, for a single unit discharging to a single stack, as the load increases, the flow rate increases proportionally, and the flow rate at a given load should remain relatively constant if the same type of fuel is burned. Common stacks are somewhat less predictable, because the same combined unit load can be produced in a number of ways by using different combinations of boilers. Despite this, if the diluent gas concentration is properly taken into account, the flow-to-load characteristics of common stacks often become more normalized. The flow-to-load ratio, or a normalized ratio, such as the gross heat rate (GHR) can thus serve as a quantitative indicator of flow monitor accuracy from quarter to quarter until the next RATA is performed.

The proposed rule provided a calculation methodology for the quarterly flow-to-load or GHR evaluation. A ''reference'' flow-to-load ratio or GHR would be established at the time of each normal-load flow RATA, using data from the flow rate reference method. Then, in subsequent quarters, hourly data from the flow monitor would be compared to the reference ratio or GHR, and an absolute average percentage difference between the hourly data and the reference ratio would be calculated. If the percentage difference exceeded certain limits, the utility would be required to investigate to try to establish the cause of the test failure. If the investigation indicated a problem with the flow monitor, the utility could perform corrective actions, followed by an abbreviated flow-to-load diagnostic test, to demonstrate that the corrective actions were effective. However, if the investigation could not establish the cause of the flow-to-load test failure, a normal load flow RATA would be required.

Today's final rule adopts the flow-to-load ratio test provisions. The final rule is essentially the same as the proposal except for a few minor changes in response to comments received.

Discussion: EPA received comments on the proposed quarterly flow-to-load ratio test from seven utilities, two state agencies, one utility regulatory response group and one flow monitor vendor. One state agency was supportive of the test, because it can serve as a quantitative indicator of flow monitor performance from quarter to quarter (see Docket A–97–35, Item IV–D–9). The flow monitor vendor also favored the test, because it will help to ensure that all flow monitoring technologies perform in a reliable manner (see Docket A–97–35, Item IV–D–12). Several utility commenters objected to the proposed test, believing it would be burdensome, time-consuming, expensive to implement (requiring significant DAHS software modifications), and difficult to pass (see Docket A–97–35, Items IV–D–16, IV–G–5, IV–G–9, IV–G–2). One commenter suggested that the test be used as a warning to take corrective action rather than using it to directly validate or invalidate flow rate data (see

Docket A–97–35, Item IV–D–11). Another commenter recommended that for common stacks, additional hours be exempted from the data analysis, specifically hours in which the combination of boilers and loads does not match the combination used during the last normal load flow RATA (see Docket A–97–35, Item IV–D–17). Two commenters recommended increasing the threshold to qualify for a less stringent flow-to-load specification from 50 MW to 60 or 70 MW (see Docket A–97–35, Items IV–D–11, IV–D–2). Two commenters recommended reducing the frequency of flow RATAs based on good performance in the flow-to-load test; specifically, one commenter advocated performing flow RATAs every other year and the other commenter recommended performing a flow RATA once every five years (see Docket A–97–35, Items IV–D–22, IV–G–2). One commenter stated that the proposed flow-to-load methodology does not adequately address multiple stack configurations where one of the stacks is a bypass stack, and also recommended that EPA make it clear that the flow-to-load data analysis only applies to reported data and not to redundant backup monitor data which are not reported (see Docket A–97–35, Item IV–G–2). Finally, the utility regulatory response group found the proposal to be an improvement over the pre-proposal draft that was circulated in May, 1997, but took issue with the following: (1) The method of calculating the test results, using the absolute value of, rather than the arithmetic, percentage of differences between the hourly flow-to-load ratios and the reference ratio; (2) failure of the proposal to address units with bypass stacks or other complex stack configurations; and (3) allowing only one week after the end of the quarter to investigate and troubleshoot the flow monitor when a flow-to-load test failure occurs, before a RATA requirement is triggered (see Docket A–97–35, Item IV–D–20).

Today's rule includes flow-to-load test provisions in section 7.7 of Appendix A and section 2.2.5 of Appendix B. The final rule is essentially the same as the proposal, except for the following changes, which have been incorporated in response to the comments received. First, a new section 7.8 has been added to Appendix A, which allows owners or operators of units with complex stack configurations to petition for an exemption from quarterly flow-to-load testing. Any such petition would have to provide information and data which demonstrate to the satisfaction of the Administrator that the flow rate through the complex stack configuration cannot be reasonably correlated to unit load. Second, for a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack (e.g., for a unit with a wet SO_2 scrubber), the flow-to-load test is to be performed on an individual stack basis and hours in which emissions are discharged simultaneously through both stacks may be excluded from the quarterly flow-to-load analysis. Third, the threshold to qualify for a less stringent flow-to-load specification has been raised from 50 MW to 60 MW. Fourth, when a flow-to-load or GHR test is failed, two weeks, rather than one, are allowed after the end of the quarter to investigate the cause of the test failure before triggering a RATA requirement.

EPA does not agree with the commenters who characterized the proposed flow-to-load test as time-consuming, burdensome, and difficult to implement (requiring extensive software revision). The Agency believes that implementation of the flow-to-load test will not require any special modification of existing part 75 DAHS systems or software. All of the information needed to perform the quarterly flow-to-load or GHR analysis is currently reported in the electronic quarterly report required under § 75.64. Rather, a PC-based computer program will be needed, which can extract the essential information from the quarterly report and analyze it. Once such a computer program is written, analysis of the quarterly flow rate and load data should become a routine operation which will be neither burdensome nor time-consuming.

The Agency also disagrees with those commenters who contended that the flow-to-load test will be difficult to pass. On the contrary, the flow-to-load test should be relatively easy to pass, provided that the flow monitor is properly operated and well-maintained. Prior to issuing the proposed rule, EPA analyzed quarterly flow rate and load data from the third quarter of 1996 for 21 units and stacks, including 9 single units, 11 common stacks, and 1 multiple-stack unit. The units chosen for this analysis were selected as a representative sample of units that would be affected by this QA test requirement and included various operational circumstances (e.g., base loaded and peaking units, single fuel units, and units that burn multiple fuels). The flow-to-load and GHR test methodologies were applied to each unit or stack, excluding none of the normal load data from the analysis. The results of the flow-to-load and GHR data analyses were nearly the same. Only one failure of the quarterly flow-to-load test was observed in each analysis (i.e., the failure rate was <5.0 percent). The value of E_f (the average percentage difference between the hourly ratios and the reference ratio) was 6.1 percent for the analysis of the flow-to-load ratios and 6.4 percent for the simulated GHR analysis (with diluent gas corrections). However, as noted by one of the commenters, the Agency acknowledges that these data analyses were performed using the calculation method described in the May, 1997 pre-proposal draft of the rule revisions, i.e., using the arithmetic percentage difference between each hourly flow-to-load ratio and the reference ratio, rather than the absolute percentage difference prescribed in the proposed rule. To address the commenter's concern, EPA has re-analyzed the data using the absolute percentage difference. The results of the data analysis using the absolute percentage difference were nearly the same as the results using the arithmetic percentage difference. The failure rate was the same (<5%) and the value of E_f was 7.3 percent for the analysis of the flow-to-load ratios and 8.0 percent for the simulated GHR analysis (with diluent gas corrections), which is still well below the 15.0 percent tolerance limit (see Docket A–97–35, Item IV–A–3). Thus, it appears to make very little difference, in terms of ease of passing, whether the absolute percentage difference or the arithmetic percentage difference is used in the flow-to-load and GHR calculations. Therefore, the flow-to-load and GHR calculation methodology has been finalized as proposed using the absolute percentage difference.

Two commenters suggested that the flow RATA frequency should be reduced based on good performance on the quarterly flow-to-load test (see Docket A–97–35, Items IV–D–22 and IV–G–02). The Agency agrees with the commenters that with the addition of the new QA tests it is reasonable to lessen the frequency of the annual three load flow RATA. Therefore, EPA is also adopting the following three provisions reducing the flow RATA requirements: (1) Routine flow RATAs are changed from three-load tests to two-load tests; (2) a single-load annual flow RATA is allowed if the unit operates at one load level for ≥85 percent of the time since the last annual flow RATA; and (3) a three-load flow RATA is required only once every five years and whenever the instrument is re-linearized. EPA has adopted these reduced flow RATA requirements principally because of the reasonable assurance of data quality that will be provided in between RATAs by the new flow-to-load test. Note, however, that the flow-to-load ratio test, which analyzes a limited amount of flow rate data at a single load level, does not serve as a replacement for annual RATA testing. Rather, the flow-to-load ratio test helps to ensure that the flow monitor remains accurate in between successive semiannual or annual RATAs.

F. RATA and Bias Test Requirements

1. RATA Load Levels

Background: The previous provisions of part 75 were neither sufficiently standardized nor clear in defining the appropriate load levels for RATAs. For example, the previous rule required gas monitor RATAs to be conducted at normal load and required gas and flow rate monitor bias adjustment factors to be determined at normal load, but no definition of normal load was provided. In addition, section 6.5.2 of Appendix A specified that the ''low'' load audit point for a 3-level flow RATA can be located anywhere from the minimum safe, stable load to 50.0 percent of the maximum load, and no minimum separation is required between the audit points at adjacent load levels. If adjacent audit points are too close together, a multiple load flow evaluation loses its significance.

EPA proposed revisions to Appendix A of part 75, which would more clearly define the load levels at which RATAs are done in order to achieve greater consistency in the way that RATAs are performed. The proposed methodology, which would become effective as of April 1, 2000, would require the utility to define the ''range of operation'' for each affected unit or common stack (except for peaking units). The range of operation would extend from the minimum safe, stable load to the maximum achievable load. The ''low'' load level would then be defined as 0–30% of the range of operation, the ''mid'' load level would be 30–60% of the range and the ''high'' load level would be 60–100% of the range. The proposed methodology would require a load frequency distribution (histogram) to be developed, prior to each annual RATA, to determine the percentage of time the unit or stack has operated at each load level in the previous four ''QA operating quarters.'' A summary of the data used for the load frequency determination would be maintained on-site in a format suitable for inspection, and the results of the determination would be included in the electronic quarterly report under § 75.64. The most frequently used load level would then be designated as the ''normal'' load. The second most frequently used load could, at the discretion of the owner or operator, be designated as a second normal load level. Gas monitor RATAs would be required at the normal load level. Routine quality assurance RATAs for flow monitors would be done at the two most frequently used load levels. Today's rule adopts the proposed changes with certain modifications in response to comments.

Discussion: The Agency received comments on the proposed method of determining RATA load levels from three individual utilities and from two utility regulatory response groups. Only two comments were received on the proposed definitions of ''range of operation,'' ''low,'' ''mid,'' and ''high'' load levels. One commenter supported the effort to establish load level definitions, but found the proposal to be too inflexible and complicated and suggested that EPA should permit overlapping load ranges (see Docket A–97–35, Item IV–D–20). The other commenter requested that EPA modify the proposed definition of the ''minimum safe, stable load'' for common stacks. The commenter expressed concern that for base-loaded units which share a common stack, the proposed definition might require a unit to be shut down to attain the low load level in a 3-load flow RATA (see Docket A–97–35, Item IV–D–24). Four commenters opposed the proposed requirement to develop a historical load frequency distribution to establish the normal load level(s) for the unit or stack, stating that the load frequency is too variable (being dependent on unit availability, operation, and dispatch) and that the new requirement would add another level of unnecessary data collection and manipulation (see Docket A–97–35, Items IV–D–20, IV–D–24, IV–D–19, and IV–D–23). Another commenter suggested that RATA load ranges should be based on the typical load requirements for the quarter in which the RATA is done, particularly if the historical data are no longer representative. The commenters further recommended that EPA should: (1) eliminate the requirement to use four operating quarters of data; (2) allow extenuating data to be excluded; (3) allow recent changes to be considered when selecting load ranges; and (4) allow utilities to consider forecasted usage of a unit when selecting load ranges (see Docket A–97–35, Item IV–D–20). Finally, one commenter objected to the proposed requirement to report the results of the load frequency data analysis electronically, stating that requiring electronic reporting of the results provides no advantage over keeping the data analysis on-site and that such reporting would require DAHS software changes (see Docket A–97–35, Item IV–G–2).

Today's rule finalizes the proposed definitions of the ''range of operation,'' and the ''low,'' ''mid,'' and ''high'' load levels in section 6.5.2.1 of Appendix A and the associated requirement to report the upper and lower boundaries of the range of operation, with one minor revision. A provision has been added for frequently-operated (e.g., base-loaded) units that share a common stack, which allows the ''minimum safe, stable load'' to be determined in a different manner. For such units, the owner or operator may use the sum of the minimum safe, stable loads for the individual units as the minimum safe stable load for the common stack (rather than using the lowest of the minimum safe, stable load values for the individual units). The Agency believes that this adequately addresses the commenter's concern that one or more units might have to be shut down in order to attain the ''low'' load level during a 3-load flow RATA.

Section 6.5.2.1 of Appendix A of today's rule also finalizes the proposed methodology for determining normal load and for selecting the appropriate load levels for the annual 2-load flow RATAs, with revisions based on comments received. In the final rule, a determination of the normal load level(s) and the appropriate flow RATA load levels is still required, but it has been made a one-time requirement, rather than an annual requirement. The requirement becomes effective on April 1, 2000, but owners or operators may comply with it prior to that date. The owner or operator must review historical load data for the unit or stack, for a minimum of four representative operating quarters. From these data, the percentage of unit operating time at each load level (''low,'' ''mid'' or ''high'') will be determined. The historical load data may be analyzed by any suitable means; construction of a histogram, per se, is not required. The load level used the most frequently will be designated normal, and the second most frequently used load level may, at the discretion of the owner or operator, be designated as a second normal load. The two most frequently used load levels are the load levels at which the annual 2-load flow RATA will be performed. The results of the historical load data analysis will be reported in the electronic quarterly report as part of the electronic monitoring plan. EPA believes that reporting one additional monitoring plan record will not prove to be burdensome. A summary of the data used for the load determinations and the calculated results must be kept on-site, in a format suitable for inspection.

EPA continues to believe that a review of historical operating load data is a reasonable way to standardize the determination of the normal load level(s) and the appropriate flow RATA load levels for a unit or stack. In order to maintain national consistency and to ensure that a ''level playing field'' is maintained among affected utilities, the Agency believes that a standardized procedure is necessary. Although several commenters took issue with the specifics of the proposed methodology, none of them provided a sufficiently detailed alternative procedure for serious consideration by the Agency. Requests to ''allow exclusion of extenuating data'' and ''permit consideration of recent changes when selecting load ranges'' do not provide a sufficient basis for the development of appropriate regulatory language. Further, since the standardized procedure is based on data for four operating quarters, any unrepresentative data is likely to have minimal effect. Therefore, EPA did not incorporate most of the commenters' suggestions. However, to address the concern of several commenters about possible variability in unit load and manner of unit operation, a provision has been added to section 6.5.2.1 of Appendix A which requires the historical load analysis to be repeated if the way in which a unit operates changes significantly and the previously-determined normal load level(s) and the two most frequently used load levels change. The new provision requires a minimum of two representative operating quarters of historical load data to document that a change in the manner of unit operation has actually occurred.

2. Single-Point Reference Method Sampling

Background: Section 6.5.6 of Appendix A to part 75 gives the traverse point location requirements for reference method sampling during relative accuracy test audits (RATAs) of gas monitoring systems. The reference method sampling points are to be located along a line, in accordance with section 3.2 of Performance Specification No. 2 in Appendix B to 40 CFR part 60. Performance Specification No. 2 requires three reference method sampling points for each RATA test run. EPA proposed changes to section 6.5.6 of Appendix A, pertaining to RATA traverse point selection. Proposed section 6.5.6 would allow single-point reference method sampling to be used in two specific instances: (1) for all moisture determinations, a single reference method point, located at least 1.0 meter from the stack wall, could be used; and (2) for flue gas sampling, a single reference method measurement point, located no less than 1.0 meter from the stack wall, could be used at any test location if a stratification test is performed prior to each RATA at the location and certain acceptance criteria are met.

In order to implement the second option (single-point gas sampling), a 12-point stratification test, as described in proposed section 6.5.6.1, would have to be passed one time at the sampling location, meeting the acceptance criteria for single-point sampling given in proposed section 6.5.6.3 of Appendix A. The location would qualify for single-point gas sampling if the concentration at each individual traverse point differed by no more than ± 5.0 percent from the arithmetic average concentration for all traverse points. The results would also be acceptable if the concentration at each individual traverse point differed by no more than ± 3.0 ppm or 0.3 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points. Once a 12-point stratification test was passed at the candidate sampling location, either the 12-point test or an abbreviated 3-point or 6-point stratification test, as described in proposed section 6.5.6.2, would have to be passed prior to subsequent RATAs at the location.

Today's rule finalizes the provisions for single-point moisture and gas reference method sampling, with certain modifications in response to comments received. The criteria in today's rule to qualify for single-point sampling are more stringent than the criteria in the proposed rule.

Discussion: EPA received comments from two utilities and three State air regulatory agencies on the proposal to allow single-point reference method sampling. One of the utility commenters favored allowing single-point sampling, viewing it as an excellent step to improve the overall efficiency of RATA testing (see Docket A–97–35, Item IV–D–21). The other utility commenter also favored the proposal, believing that it would reduce the manpower requirements for gas RATA testing (see Docket A–97–35, Item IV–D–22). One State agency commenter opposed the unrestricted use of single-point moisture sampling, stating that the moisture results could be biased if gas stratification is present in the stack. Another State agency commenter viewed the proposal to allow single-point reference method sampling as unfavorable, expressing concern that single-point sampling may not yield valid results, particularly if the sampling point is too near the stack wall, where air in-leakage can occur (see Docket A–97–35, Item IV–D–9). The third State agency commenter appeared to take issue with the use of a 3-point abbreviated stratification test, stating that for the large-diameter stacks in the Acid Rain Program, a three point test is not adequate to demonstrate the absence of stratification.

In response to the comments received, the single-point reference method provisions in section 6.5.6 of Appendix A of today's rule are more restrictive than the provisions in the proposal. After careful consideration, EPA has decided to allow single-point reference method sampling, but to place additional restrictions on its use. The Agency believes that some of the state agency commenters' concerns about the proposed single-point sampling methodology are valid. Accordingly, today's final rule addresses these concerns.

Today's rule allows the unrestricted use of single-point moisture sampling only in applications where the moisture data are used to determine the stack gas molecular weight. For all other moisture measurement applications, i.e., for moisture monitoring system RATAs or when moisture data are used to correct emission data from a dry basis to a wet basis (or vice-versa), single-point moisture sampling is only permitted if a 12-point pollutant or diluent gas stratification test is performed and passed (at the 5.0 percent specification in section 6.5.6.3 of Appendix A) prior to the RATA. Similarly, for flue gas sampling, today's rule allows the use of single-point reference method sampling only if a 12-point gas stratification test is performed and passed at the 5.0 percent specification prior to the RATA. Use of an abbreviated (3- or 6-point) stratification test as a means of qualifying for single-point sampling is not allowed.

Finally, when a test location qualifies for single-point reference method sampling, today's rule specifies that the measurement point must be located at least 1.0 meter from the stack wall and must be situated along one of the measurement lines used in the 12-point stratification test. EPA believes that these modifications to the proposed single-point reference method sampling methodology are necessary to ensure that representative samples will continue to be obtained.

G. Data Validation

1. Data Validation During Monitor Certification and Recertification

Background: The previous version of part 75 specified that for any replacement, change, or modification to a monitoring system requiring recertification of the CEMS, all data from the CEMS are invalid from the hour of that replacement, change, or modification until the hour of completion of all required recertification tests. The proposed rule would have revised § 75.20(b)(3) to conditionally allow emission data generated by the CEMS during a recertification test period to be used for part 75 reporting, provided that the required tests are successfully completed in a timely manner and that certain data validation rules are followed during the recertification test period. Proposed sections 6.2, 6.3.1, and 6.5 of Appendix A would have allowed these new data validation procedures to also be applied to the initial certification of monitoring systems. The intended purpose of the proposed revisions is to minimize the number of hours of substitute data or maximum potential values that must be reported during a monitor certification or recertification period.

In proposed § 75.20(b)(3), specific rules were provided for data validation during the recertification test period. The recertification test period would begin with the first successful calibration error test (known as a ''probationary calibration error test'') after making the change to the CEMS and completing all necessary post-change adjustments (e.g., reprogramming or linearization) of the CEMS. The post-change activities could include preliminary tests such as trial RATA runs or a challenge of the monitor with calibration gases. Data from the CEMS would be considered invalid from the hour in which the replacement, modification, or change to the system is commenced until the hour of completion of the probationary calibration error test, at which point the data status would become ''conditionally valid.''

The conditionally valid status of the CEMS data would continue throughout the recertification test period, provided that the required recertification tests were done ''hands-off'' (i.e., with no adjustments, such as reprogramming or linearization of the CEMS, other than the calibration adjustments allowed under proposed section 2.1.3 of Appendix B) and provided that the recertification tests and required daily calibration error tests continued to be passed. If all of the required recertification tests and calibration error tests were passed hands-off, with no failures and within the required time period, then all of the conditionally valid emission data recorded by the CEMS during the recertification test period would be considered quality assured and suitable for part 75 reporting. However, if any required test was failed, the conditionally valid data would, in most cases, be invalidated and a new recertification test period would have to be initiated, following corrective actions.

Today's rule finalizes the CEMS validation procedures for certifications and recertifications, with certain modifications in response to comments received.

Discussion: EPA received strongly supportive comments on the proposed revisions to § 75.20(b)(3) from five utilities, one state air regulatory agency and two utility regulatory response groups. However, two utilities asked the Agency to modify the proposal to allow trial gas injections and preliminary RATA runs to be done during the recertification test period, rather than prior to it. One commenter stated that preliminary gas injections and RATA runs, which are considered to be a valuable maintenance tool, should be allowed following the probationary calibration error test, and, provided that the results of the trial runs are acceptable, the recertification should be allowed to proceed (see Docket A–97–35, Item IV–G–3). Another commenter requested that the proposal be revised to allow a single challenge with each of the three gases prior to a linearity test and to allow up to five preliminary trial runs prior to a RATA (see Docket A–97–35, Item IV–G–5).

Today's rule finalizes the proposed data validation procedures in § 75.20(b)(3) for monitor certification and recertification, with the following modifications in response to the comments. First, an introductory statement of applicability has been added at the beginning of § 75.20(b)(3), clearly indicating that the provisions of the section apply both to recertifications and to initial certifications. The statement of applicability also allows the data validation procedures to be applied, at the discretion of the owner or operator, to the routine quality assurance linearity tests and RATAs required under Appendix B of part 75 (see the section on ''Data Validation for RATAs and Linearity Checks'' in this preamble, for a further discussion of this option). Second, proposed paragraph (b)(3)(x) of § 75.20 has been merged with proposed paragraph (b)(3)(i), for greater clarity; both paragraphs deal with missing data substitution prior to the recertification test period. Third, the definition of a ''hands-off'' recertification test in § 75.20(b)(3)(v) has been revised to make it clear that once a recertification test has begun, only routine calibration adjustments following daily calibration error tests are permitted until the test is completed. Fourth, language has been added to § 75.20(b)(3) to address the case in which a multi-load flow RATA is passed at one or more load levels and then failed at a subsequent load level.

Regarding the fourth revision to § 75.20(b)(3) described in the previous paragraph, 2.3.2(e) of Appendix B of today's rule states that in such cases, only the RATA at the failed load level needs to be repeated (unless re-linearization of the monitor is necessary, in which case a 3-load RATA is required). Because of this new Appendix B provision, the following corresponding data validation provisions have been added to §§ 75.20(b)(3)(vii)(A) and 75.20(b)(3)(vii)(B): (1) upon failure of the RATA at the particular load level, the length of the new recertification test period is not 720 unit operating hours, but is equal to the number of hours remaining in the original recertification test period at the time of test failure; and (2) data invalidation is prospective, beginning with the hour of failure of the RATA at the particular load level; therefore, conditionally valid data recorded prior to the test failure at the particular load level are not invalidated. Finally, in response to the comments received, a new paragraph, (b)(3)(vii)(E), has been added to § 75.20 to address the issue of trial RATA runs and pre-test gas injections. Section 75.20(b)(3)(vii)(E) allows pre-test trial gas injections and pre-RATA runs to be done during the recertification period, for the purpose of optimizing the performance of the monitoring system. A trial run or injection will not affect the status of previously-recorded conditionally valid data, provided that: (1) the results of the trial run are within the Appendix A specifications for a passed linearity test or RATA (i.e., for a trial gas injection, within ±5% or 5 ppm of the reference gas or, for a trial RATA run, if the average reference method and the average CEMS readings differ by no more than ±10% of the reference method value, or ±15 ppm, or ±0.02 lb/mmBtu, or ±1.5% H_2O, as applicable); (2) no adjustments are made to the calibration of the CEMS following the trial run, other than the adjustments allowed under section 2.1.3 of Appendix B; and (3) the CEMS is not repaired, re-linearized, or reprogrammed after the trial run. As long as these conditions continue to be met, the CEMS can be further optimized without data loss. However, if, for any trial run or injection the conditions are not met, the trial run or injection is treated as a failed or aborted linearity check or RATA and the applicable provisions in §§ 75.20(b)(3)(vii)(A) and 75.20(b)(3)(vii)(B) pertaining to aborted or failed recertification tests must be followed.

2. Data Validation for RATAs and Linearity Checks

Background: EPA proposed rules for CEMS data validation prior to and during the periodic linearity tests and RATAs required by part 75. These new provisions were found in proposed sections 2.2.3 and 2.3.2 of Appendix B. According to these provisions, a linearity test or RATA could not be started if the CEMS were operating ''out-of-control'' with respect to any of its other daily, semiannual, or annual quality assurance tests. Prior to the test, both routine and non-routine calibration adjustments, as defined in proposed section 2.1.3 of Appendix B, would be permitted. During the linearity or RATA test period, however, no adjustment of the monitor would be permitted except for routine daily calibration adjustments following successful daily calibration error tests. For 2-level and 3-level flow RATAs, no linearization of the monitor would be permitted between load levels. If a linearity check or RATA was failed or aborted due to a problem with the monitor, the monitor would be declared out-of-control as of the hour in which the test is failed or aborted. Data from the monitor would remain invalid until the hour of completion of a subsequent successful test of the same type.

The proposed rule also attempted to clarify the way in which linearity and RATA test results are to be reported to EPA in the electronic quarterly report required under § 75.64. Proposed sections 2.2.3 and 2.3.2 of Appendix B specified that only the results of completed and partial tests which affect data validation would have to be reported. That is, all completed passed tests, all completed failed tests, and all tests aborted due to a problem with the CEMS would have to be included in the quarterly report. Therefore, aborted test attempts followed by corrective maintenance, re-linearization of the monitor, or any other adjustments other than those allowed under proposed section 2.1.3 of Appendix B would have to be reported. However, tests which are aborted or invalidated due to problems with the calibration gases or reference method or due to operational problems with the affected unit(s) would not need to be reported, because such runs do not affect the validation status of emission data recorded by the CEMS. In addition, aborted RATA attempts which are part of the process of optimizing a monitoring system's performance would not have to be reported, provided that in the period from the end of the aborted test to the commencement of the next RATA attempt: (1) no corrective maintenance or re-linearization of the CEMS was performed, and (2) no adjustments other than the calibration adjustments allowed under proposed section 2.1.3 of Appendix B were made. However, such aborted RATA runs would still have to be documented and kept on-site as part of the official test log.

Today's rule finalizes the CEMS data validation requirements for RATAs and linearity checks. The final rule has been modified from the proposal, based on comments received.

Discussion: EPA received comments on the proposed data validation procedures for RATAs and linearity checks from one state air regulatory agency, two utilities and one utility regulatory response group. Two of the commenters found the proposed rule language defining the allowable pre-test adjustments to be inconsistent with the preamble language found at 63 FR 28075. The commenters noted an apparent contradiction between the preamble statement that there is ''no significant risk in allowing pre-RATA adjustments provided that the monitor's accuracy between successive RATAs can be reasonably established'' and the rule language in section 6.5(a)(1) of Appendix A that ''no adjustments, linearizations or reprogramming of the CEMS other than the calibration adjustments described in section 2.1.3 of Appendix B to this part, are permitted prior to and during the RATA test period.'' Both commenters expressed concern that this proposed rule language appeared to exclude important activities such as re-linearization of a flow monitor (see Docket A–97–35, Items IV–D–20, IV–G–2). Another commenter also objected to the proposed language in section 6.5(a)(1) of Appendix A, stating that technicians need to be able to perform evaluations and adjustments of flow and gas measurement systems prior to conducting a RATA (see Docket A–97–35, Item IV–G–3). Another commenter took issue with the provisions in proposed sections 2.2.3 and 2.3.2 of Appendix B which allow ''non-routine'' adjustments to be made prior to linearity tests and RATAs. The commenter especially objected to the idea of allowing adjustments in a direction away from the reference gas tag value, believing that this compromises the integrity of the audit and sets an ''unfortunate precedent'' (see Docket A–97–35, Item IV–D–11).

Today's rule finalizes the data validation provisions for linearity checks and RATAs in sections 2.2.3 and 2.3.2 of Appendix B. Based on the comments received, EPA has made substantive revisions to the proposed rule in an attempt to clarify the allowable pre-test adjustments and the rules for validating the CEMS data. Today's rule specifies that when a linearity check or RATA is due, the owner or operator has three options. First, the test may be done ''cold,'' with no pre-test adjustments of any kind. Second, the test may be done after making only the routine or non-routine calibration adjustments allowed under section 2.1.3 of Appendix B. Under this second option, trial gas injections and preliminary RATA runs are allowed, followed by additional adjustments (if necessary) within the limits of section 2.1.3 of Appendix B, to optimize the monitor's performance. The trial runs or injections need not be reported, provided that they meet the acceptance criteria for trial RATA runs and gas injections in § 75.20(b)(3)(vii)(E) (see the section of this preamble entitled ''Data Validation During Monitor Certification and Recertification'' for further discussion of these acceptance criteria). If the acceptance criteria are not met, the trial run is counted as a failed or aborted test. Third, the CEMS may be repaired, re-linearized or reprogrammed prior to the quality assurance test. In this case, the CEMS may either be considered out-of-control from the hour of commencement of the corrective maintenance, re-linearization or reprogramming until completion of the required quality assurance test or the owner or operator may follow the data validation procedures in § 75.20(b)(3) upon completion of the necessary corrective maintenance, re-linearization, or reprogramming.

EPA believes that the revisions to sections 2.2.3 and 2.3.2 of Appendix B address the commenters' concerns about pre-test adjustments. For example, if, at the time of a scheduled flow RATA, the owner or operator decides to re-linearize the primary flow monitor to optimize its performance, this would be permissible under the third option above. However, re-linearization of a flow monitor triggers a requirement to perform a 3-load RATA. Therefore, if the monitor is declared out-of-control from the hour of the re-linearization until the hour of completion of the 3-load RATA (as would be required by the proposed rule), this could result in significant data loss, since a 3-load RATA can take days (or even weeks) to complete, depending on electrical demand. For this reason, today's rule allows the owner or operator to use the recertification data validation procedures in § 75.20(b)(3) to supplement the quality assurance provisions in Appendix B. In this example, if the owner or operator opts to use the data validation procedures in § 75.20(b)(3), data from the flow monitor would be considered conditionally valid upon completion of a ''probationary calibration error test,'' following the re-linearization of the monitor. The procedures in § 75.20(b)(3)(vii)(E) allow for trial runs and further optimization of the monitor prior to the RATA. If the 3-level flow RATA is then passed in accordance with the procedures of § 75.20(b)(3) and within the allotted time frame (indicating that the re-linearization was successful), the conditionally valid data will become quality assured and may be used for reporting.

For the following reasons, EPA does not agree with the commenter who opposed allowing ''non-routine'' calibration adjustments prior to a quality assurance test. The ''non-routine'' adjustments described in section 2.1.3 of Appendix B allow adjustments only within the performance specifications of the instrument. When a monitor is initially certified, it must pass several quality assurance tests, one of which is a 7-day calibration error test. The monitor must demonstrate, for 7 consecutive operating days, that it is capable of meeting a calibration error specification of ±2.5 percent of the instrument span (±3.0 percent for flow monitors). Once a monitor has been certified, the ''control limits'' for daily calibration error tests of the monitor are twice the performance specification value, i.e., ±5.0 percent of span for gas monitors and ±6.0 percent for flow monitors. Thus, when the ''non-routine'' adjustments described under section 2.1.3 of Appendix B are made prior to a linearity test or RATA, the monitor is actually being held to a tighter specification than is used for daily operation. The Agency therefore does not agree that keeping the instrument's calibration within the performance specification ''band'' at the time of linearity tests or RATAs compromises the integrity of the audits or sets a bad precedent. On the contrary, it demonstrates that the monitor continues to perform in a comparable manner to its performance at the time of initial certification. When the monitor is held to the calibration error specification required for initial certification, the monitor is shown to be capable of passing a linearity test or RATA.

H. Appendix D—Sulfur Dioxide Emissions From the Combustion of Gaseous Fuels

Background: EPA proposed several revisions to the procedures in Appendix D of part 75 for determining sulfur dioxide emissions from gas-fired and oil-fired units. Most of the proposed revisions would provide affected utilities with additional flexibility and sampling options. These changes were generally supported by the comments received and have either been finalized as proposed or with minor revisions and clarifications. However, for gaseous fuels, EPA received a number of significant comments concerning the proposed changes to the definition of the term ''pipeline natural gas'' under § 72.2 and received other comments which have prompted the Agency to re-evaluate the applicability and use of Appendix D. In response to the significant comments received, the Agency is adopting the following final revisions to Appendix D and to § 72.2:

(1) Revised definitions of ''pipeline natural gas,'' ''natural gas'' and ''gas-fired'' have been promulgated in § 72.2;

(2) The applicability of Appendix D has been expanded to include gaseous fuels with any sulfur content (previously, Appendix D had been limited to gaseous fuels with a sulfur content of 20 grains per 100 scf, or less); and

(3) The methodology for determining the frequency of fuel gross calorific value (GCV) under section 2.3 of Appendix D has been modified.

In order to put today's revisions in context, it is necessary to review how the Agency addressed these issues in previous rulemakings. Section 2.4 of Appendix D of the core rules of the Acid Rain Program issued on January 11, 1993, allowed units combusting ''natural gas'' (as defined in § 72.2) to calculate SO_2 mass emissions through either: (1) fuel sulfur sampling and measurement of the fuel flow rate by a certified fuel flowmeter; or (2) the use of a default SO_2 emission rate of 0.0006 lb/mmBtu and heat input determined using a certified fuel flowmeter and monthly analysis for fuel GCV. In the preamble to the January 11, 1993 rule, the Agency stated, ''the definition of ''natural gas'' does not, therefore, include landfill gas, digester gas, biomass, or gasified coal'' (58 FR 3590 and 3596). The Agency further stated in the preamble that, ''essentially sulfur-free fuels such as natural gas, landfill methane, or synthetic propane'' should qualify for the use of Appendix D methodologies. The intent of the Agency in that rulemaking was to allow the use of a default emission rate for SO_2 mass emissions calculations for natural gas and other fuels which have a similar low sulfur content, but not for fuels which have higher sulfur content than natural gas. Appendix D did not effectively address how to determine SO_2 mass emissions for gaseous fuels other than natural gas.

On May 17, 1995 the Agency revised the core Acid Rain rules to add a new definition for ''pipeline natural gas,'' and revised the definitions of ''natural gas'' and ''gas-fired.'' The most significant change in the definition of ''natural gas'' was the addition of the requirement that ''natural gas'' must contain ''one grain or less hydrogen sulfide per 100 standard cubic feet and 20 grains or less total sulfur per 100 standard cubic feet.'' The intent of this additional language was to clarify which gaseous fuels qualified as ''natural gas.'' The criteria used (1 grain hydrogen sulfide (H_2S) and 20 grains total sulfur) were based on contracts and tariff sheets for pipeline natural gas regulated by the Federal Energy Regulatory Commission (FERC). Consistent with this approach, the Agency defined ''pipeline natural gas'' as natural gas provided by a supplier through a pipeline. In addition, the Agency modified the definition of ''gas-fired'' to make it clear that the use of Appendix D was limited to units combusting ''fuel oil,'' ''natural gas,'' and ''gaseous fuels containing no more sulfur than natural gas.'' The default SO_2 emission rate of 0.0006 lb/mmBtu could only be used for the combustion of either natural gas or a fuel with a sulfur content no greater than natural gas. To use the default SO_2 emission rate, the owner or operator was required to demonstrate that the fuel being combusted qualified as natural gas, based on contract or tariff values which indicate that the gas meets the criteria for natural gas H_2S content and total sulfur content.

As noted in the preamble of the proposed rule, the May 12, 1995 revisions apparently did not eliminate confusion concerning the use of the default SO_2 emission rate. The SO_2 default emission rate of 0.0006 lb/mmBtu is equivalent to approximately 0.2 grains hydrogen sulfide per 100 standard cubic feet (scf) of gas, when hydrogen sulfide is the sole source of total sulfur in the gas (as is the case for refined natural gas), or 0.2 grains total sulfur per 100 scf of gas. The Agency did not intend that fuels with average sulfur content much higher than 0.2 grains per 100 scf should be allowed to use the default value. In this context, the current definition of ''natural gas'' under § 72.2, which includes the term ''20 grains of total sulfur,'' is somewhat confusing. Further, use of the 0.0006 lb/mmBtu default emission rate for ''natural gas'' with one grain of H_2S per 100 scf would result in an approximately five-fold underestimation of SO_2 emissions. Therefore, in the proposed rule, the Agency modified the definition of pipeline natural gas to include only natural gas with a hydrogen sulfide content less than or equal to 0.3 grains hydrogen sulfide per 100 scf, thereby clarifying that the default emission rate of 0.0006 lb/mmBtu could only be used for natural gas with an appropriately low hydrogen sulfide content.

The proposed rule required documentation of the hydrogen sulfide content of the natural gas either through quality characteristics specified by a purchase contract or pipeline transportation contract, through certification of the gas vendor, based on routine vendor sampling and analysis, or through at least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken at least monthly, demonstrating that all samples contain 0.3 grains or less of hydrogen sulfide per 100 standard cubic feet. For a fuel to be classified as ''pipeline natural gas'' the fuel would, of course, first have to meet the current definition of ''natural gas'' in § 72.2, which states, ''Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) containing 1 grain or less hydrogen sulfide per 100 standard cubic feet, and 20 grains or less total sulfur per 100 standard cubic feet), produced in geological formations beneath the Earth's surface, and maintaining a gaseous state at standard atmospheric temperature and pressure under ordinary conditions.''

Discussion: Several comments were received on the proposed changes to the definition of ''pipeline natural gas,'' and comments were also received on the current definition of ''natural gas.'' In responding to the comments, the Agency is revising both the definition of ''pipeline natural gas'' and ''natural gas,'' as well as making various corresponding changes to wording in part 75 to ensure consistency within the rule.

Two commenters were opposed to the change to the definition of pipeline natural gas (see Docket A–97–35, Items IV–D–23 and IV–D–24). Both commenters suggested that the requirement to document that a gaseous fuel has ≤0.3 gr/100 scf of H_2S, as opposed to the previous requirement to document an H_2S content ≤1.0 gr/100 scf, would either disqualify some sources currently using the default emission rate of 0.0006 lb/mmBtu or force those sources to use means other than the contract or tariff provisions to demonstrate that the hydrogen sulfide content of the gas is less than 0.3 gr./100 scf. Under the proposed Appendix D revisions, any sources disqualified from the use of the default SO_2 emission rate would either be required to begin daily gas sampling of the fuel sulfur content or would have to install an SO_2 CEMS.

Two other commenters suggested that the use of two sulfur content criteria in the natural gas definition (the dual criteria of 1 grain H_2S and 20 grains total sulfur per 100 scf) was confusing and could lead to misinterpretation of which fuels could be classified as either ''pipeline natural gas'' or ''natural gas'' under § 72.2 (see Docket A–97–35, Items IV–G–3 and IV–G–10). One of these commenters suggested that the definition of natural gas should be changed to incorporate only the requirement of 20 grains or less of total sulfur per 100 scf. If this suggestion were followed, a source with 20 grains total sulfur per 100 scf could use an SO_2 emission rate of 0.0006 lb/mmBtu, thereby underestimating SO_2 emissions 100-fold. This would clearly be unacceptable and contrary to the Agency's intent since the initial adoption of Appendix D.

One commenter suggested that the requirement to determine the fuel GCV on the same frequency as sulfur sampling be removed from Appendix D and that monthly GCV sampling be allowed in all cases (see Docket A–97–35, Item IV–D–20). The commenter claimed that the variability of fuel GCV is not necessarily the same as the variability of the sulfur content of a fuel.

1. Summary of EPA Analysis of Appendix D Gaseous Fuel SO_2 and Heat Input Methodologies

In responding to the comments received, the Agency first attempted to quantify the SO_2 emissions from the combustion of gaseous fuels under the current Acid Rain rules. A data analysis was performed, assuming that the vast majority of SO_2 emissions from the combustion of gaseous fuel are from affected units reporting gas as the primary fuel. The data analysis (which was limited to 1997 emission data) indicates the following: (1) there are 582 units that list gas as the primary fuel (representing about 30% of the units in the program); (2) these 582 units accounted for approximately 10% of the total heat input reported for all Acid Rain-affected units; (3) the total amount of SO_2 emitted by these 582 units was 14,728 tons in 1997 or 0.1% of the total SO_2 mass emissions in the program; and (4) of the 14,728 tons of SO_2 emitted by the 582 units, 12,844 tons were from only 17 units and the remaining 1,884 tons were from the remaining 565 units (see Docket A–97–35, Item IV–A–4). Thus it appears that gas-fired units account for a significant portion of the total heat input and electrical generation under the Acid Rain Program, but contribute only a fraction of one percent of the total SO_2 emissions. Note, however, that even though emissions from the individual gas-fired units are very small, the cumulative emissions from all 582 units are roughly equivalent to the typical SO_2 emissions from a coal-fired unit. For this reason, the method of calculating the SO_2 emissions from the gas-fired units must be sufficiently accurate to prevent significant underestimation of emissions. The methodology in the current rule allows the default SO_2 emission rate of 0.0006 lb/mmBtu to be used for all types of natural gas. As previously noted, the default emission rate corresponds to 0.2 grains of H_2S per 100 scf, but the definition of natural gas allows fuels with up to 1.0 grain of H_2S and 20 grains of total sulfur to be classified as ''natural gas.'' In view of this, it is possible that the reported cumulative SO_2 emissions reported in 1997 for the 582 gas-fired units may be inaccurate by several orders of magnitude. This level of uncertainty in reported emissions is unacceptable in an allowance trading program such as the Acid Rain Program. Consequently, a more representative method is needed to characterize the actual sulfur content of the gaseous fuels combusted by Acid Rain-affected units.

The Agency also performed an analysis of all available gaseous fuel GCV sampling data from all Acid Rain sources reporting such data in 1997. Gaseous fuels were analyzed in two categories, pipeline natural gas and ''other'' gas. Only 14 Acid Rain sources reported sampling and analysis of ''other'' gases in 1997. The data analysis showed that for 275,669 pipeline natural gas analyses, the average fuel GCV was 1023 Btu/ft^3 and the 95th percentile value was 1051 Btu/ft^3, a difference of only 2.6%. For the ''other'' gaseous fuels, the average GCV from 14,282 analyses was 819 Btu/ft^3 and the 95th percentile value was 1118 Btu/ft^3, a difference of approximately 26%. This demonstrates the consistency of the GCV of pipeline natural gas and the high variability of the few ''other'' gaseous fuels for which Appendix D is currently being used (see Docket A–97–35, Item IV–-A–1).

In finalizing today's rule, the Agency also considered the potential impact of the revisions to Appendix D on the new Subpart H of part 75 (which establishes the requirements for monitoring of NO_X mass emissions). Currently, the provisions of Subpart H are being used by the Ozone Transport Commission (OTC) NO_X Budget Program and, in the future, Subpart H may be adopted as part of an implementation plan as a means of complying with the NO_X SIP Call (see 63 FR 57356). Subpart H of part 75 allows heat input determined by the procedures of Appendix D to be used in determining NO_X mass emissions from gas-fired units. In the process of implementing part 75 and the OTC NO_X Budget Program, the Agency has encountered an increasing number of sources that combust gaseous fuels which neither qualify as ''pipeline natural gas'' or ''natural gas.'' These fuels include refinery gas, landfill gas, digester gas, coke oven gas, process gas, propane liquified gas, liquified petroleum gas, blast furnace gas and coal-derived gas. Under the previous version of part 75 units combusting these fuels would either be required to install SO_2 and stack flow monitoring systems or would have to petition the Agency to use Appendix D. It is likely that under the OTC NO_X Budget Program and under the SIP call, the number of sources combusting these ''other'' gaseous fuels and required to monitor heat input using part 75 methods will increase significantly. The Agency anticipates that the owners or operators of the majority of these sources would petition to use the procedures of Appendix D to determine heat input used for NO_X mass calculations, in lieu of installing CEMS. However, the current Appendix D does not address how to determine hourly heat input for gaseous fuels with variable GCV. The Agency also notes that any error in hourly heat input determined under Appendix D would result in a corresponding and equal error in the reported NO_X mass emissions. It is therefore particularly important to establish consistent and easily implementable heat input monitoring criteria for all types of gaseous fuels under Appendix D. Clear, flexible and reasonable requirements for gaseous fuel GCV sampling and analysis are needed.

Based on the comments received and the data analyses described above, the Agency has concluded that:

- The use of the default SO_2 emission rate of 0.0006 lb/mmBtu is only appropriate for natural gas with a documented contractual or tariff limit of 0.3 grains hydrogen sulfide per hundred standard cubic feet or for fuels which are demonstrated to have a similar low total sulfur content.
- For natural gas with a contract or tariff hydrogen sulfide limit up to 1.0 grain of hydrogen sulfide per 100 standard cubic feet, or for fuels which are demonstrated to have a similar low total sulfur content, a site-specific default SO_2 emission rate should be allowed, which more closely represents the potential SO_2 emission rate for that fuel.
- The applicability of Appendix D should be expanded to include any gaseous fuel (rather than limiting it to fuels with a total sulfur content ≤ 20 grains per 100 scf. For gaseous fuels with highly variable sulfur content, hourly sampling using advanced monitoring such as on-line gas chromatography should be required. The frequency of determination of the GCV of a gaseous fuel should be independent of the requirements for sulfur sampling and should be based solely on the variability of the GCV.

2. Changes to the Definitions of ''Pipeline Natural Gas'' and ''Natural Gas''

As previously stated, the Agency is revising the definitions of ''pipeline natural gas'' and ''natural gas'' in § 72.2. Since the definition of ''pipeline natural gas'' necessarily includes the definition of ''natural gas'', and the definitions therefore involve similar issues, EPA is addressing both definitions in today's final rule. In particular, ''pipeline natural gas'' is defined in such a way that only fuels with the appropriate sulfur content can meet the definition and can use the default emission rate of 0.0006 lb/mmBtu. Under the revised definition, pipeline natural gas must contain less than 0.3 grains of hydrogen sulfide per 100 scf. Consistent with this approach, the definition of ''natural gas'' is revised so that only the requirement for the hydrogen sulfide content to be less than one grain per 100 scf remains, and the requirement for the total sulfur content to be ≤20 grains per 100 scf is deleted. Further, EPA is adding to both definitions a requirement that hydrogen sulfide content must account for at least 50% (by weight) of the total sulfur in the fuel. This ensures that a fuel with a high total sulfur content, but a relatively small hydrogen sulfide content, cannot qualify to use a default SO_2 emission rate. The Agency believes that in general, any ''natural gas'' with ≤1.0 grain of H_2S/100 scf will also meet the requirement that hydrogen sulfide must account for ≥50% of the total sulfur in the fuel. However, the Agency reserves the right to request that the owner or operator provide data to demonstrate compliance with this latter requirement. Finally, EPA is adding a requirement to the ''natural gas'' definition that the gas must have either a methane content of at least 70% or the same GCV as methane (950 to 1100 Btu/scf). This requirement ensures that the gas will have a stable GCV, consistent with the Appendix D provisions which allow monthly GCV sampling for either pipeline natural gas or natural gas. In today's rule, the requirements for documenting that a fuel qualifies as ''pipeline natural gas'' or ''natural gas'' are essentially the same as the proposed rule. The three principal ways of providing the necessary documentation are: (1) gas quality characteristics specified in a purchase contract or pipeline transportation contract; (2) certification by the gas vendor, based on routine sampling and analysis for at least one year; and (3) at least one year of analytical data on the fuel characteristics, derived from monthly (or more frequent) samples. In addition, sections 2.3.5 and 2.3.6 of Appendix D of today's rule allow the owner or operator to conduct a 720 hour demonstration of the fuel's sulfur and GCV characteristics (see Items 5 and 6 in this section, below).

EPA believes that the revised definitions of ''pipeline natural gas'' and ''natural gas'' will: (1) apply to the low sulfur fuel combusted by the vast majority of the sources in the Acid Rain Program; (2) be documentable, in most cases, based on contract or tariff provisions without other types of demonstrations; and (3) allow most sources currently using 0.0006 lb/mmBtu as a default to continue using that default value or to use an alternative, site-specific default value that will not underestimate SO_2 emissions.

3. Changes to the Methodology for Calculating SO_2 Emissions Under Appendix D

Today's rule adopts a two-tiered approach to the use of default SO_2 emission rates, depending on whether a fuel qualifies as ''pipeline natural gas'' or as ''natural gas.'' First, if the owner or operator can demonstrate that the fuel combusted at a unit has ≤0.3 grains of hydrogen sulfide per 100 scf, the default SO_2 emission rate of 0.0006 lb/mmBtu may be used. Second, the rule allows units combusting gaseous fuels with >0.3 grains, but ≤1.0 grain of hydrogen sulfide per 100 scf to calculate a site-specific default SO_2 emission rate, as suggested by two of the commenters (see Docket A–97–35, Items IV–D–23 and IV–D–24). The method of calculating the default value is based on the actual conversion of hydrogen sulfide in natural gas to SO_2 and utilizes a realistic fuel GCV value of 1023 Btu/scf (from the previously-discussed data analysis, above). The result is a simple equation which converts hydrogen sulfide in natural gas to an SO_2 emission rate in lb/mmBtu.

4. Changes to the Applicability of Appendix D

In the process of considering comment on the definitions of ''pipeline natural gas'' and ''natural gas'' the Agency also re-evaluated the appropriateness of limiting the applicability of Appendix D to gaseous fuels with ≤20 grains of total sulfur per 100 scf. While EPA does not believe that a gaseous fuel with 20 or more grains of total sulfur per 100 scf should be allowed to use a default SO_2 emission rate, neither does the Agency believe that units combusting such fuel should be excluded from using Appendix D. Currently, technologies such as on-line gas chromatography allow accurate fuel sulfur analysis to be performed over intervals as short as one hour. This ability to perform hourly sampling is comparable to a CEMS in accuracy, precision and timeliness. Therefore, today's rule removes the 20 grains of sulfur per 100 scf restriction on the use of Appendix D for gaseous fuels.

5. Changes to the Method of Determining the Sulfur Content Sampling Frequency for Gaseous Fuels

Section 2.3.6 of Appendix D of today's rule also includes a general procedure for determining the appropriate frequency of sulfur content sampling for any gaseous fuel which is transmitted by a pipeline. The procedure consists of a 720 hour demonstration, similar to the one in section 2.3.3.4 of Appendix D in the proposed rule. The results of the 720 hour demonstration may first be used to determine first if a fuel qualifies as either ''pipeline natural gas'' or ''natural gas'' or as ''other'' gaseous fuel, and then to determine the appropriate total sulfur sampling frequency for the fuel. If a fuel qualifies as pipeline natural gas, the default SO_2 emission rate of 0.0006 lb/mmBtu could be used in lieu of fuel sampling. If the fuel qualifies as ''natural gas'' (but not pipeline natural gas), a site-specific default SO_2 emission rate may be used, based on the highest hourly hydrogen sulfide concentration recorded during the 720 hour demonstration. After a fuel qualifies as ''natural gas,'' the owner or operator is required to sample the H_2S content at least once monthly for a year following the 720 hour demonstration. The default emission rate for the demonstration may continue to be used, provided that none of the samples taken during the year exceeds 1.0 grain/100 scf of H_2S. All ''other'' gaseous fuels would require either daily or hourly sampling of the total sulfur content, depending on the fuel sulfur variability.

6. Changes to the Method of Determining the GCV Sampling Frequency for Gaseous Fuels

Accurate determinations of heat input are important for the calculation of SO_2, NO_X and CO_2 mass emissions under Appendices D, E, G and Subpart H of part 75. EPA has found that fuels such as refinery gas, digester gas, landfill gas, coke oven gas, process gas, propane liquified gas, liquified petroleum gas, blast furnace gas, and coal derived gas can have highly variable GCV (see Docket A–97–35, Item IV–A–4). For these fuels a standardized test for determining the appropriate GCV sampling and analysis frequency is essential. One commenter on the proposed rule noted that in many cases the GCV of a fuel is relatively stable over a period of time, and sampling each month for fuel heat content is adequate (see Docket A–97–35, Item IV–D–20). The Agency agrees that this is true in many cases (e.g., for natural gas), but not often for the fuels listed above. The Agency also notes that the emissions data determined under Appendix D must be as reliable, precise, timely and accessible as data from a CEMS.

In view of this, the Agency is revising the criteria for determining the frequency of GCV sampling for gaseous fuels. For any fuel which meets the revised definition of either ''pipeline natural gas'' or ''natural gas,'' this ensures that the fuel will have a stable heat content and therefore monthly sampling is appropriate. For fuels which do not qualify as either pipeline natural gas or natural gas and for which ''as-delivered'' fuel sampling and analysis is not performed, the same 720 hour demonstration described in item 5 in this section, above, for fuel sulfur sampling will also be used to determine the appropriate GCV sampling and analysis frequency. The heat content of the fuel will be determined for each hour in the 720 hour period. For units that switch fuels seasonally or when process changes occur (such as refinery fuel gas combustion units) the 720 hour demonstration period must also include data which characterizes the variability of the fuel during the seasonal or process changes. The results of the 720 hour demonstration will be used to determine the average heat content of the fuel and the standard deviation. As explained in section 2.3.5 of Appendix D in today's rule, depending on the results of the demonstration, the owner or operator will perform either daily or hourly sampling of the fuel GCV.

I. Electronic Transfer of Quarterly Reports

Background: For the reasons discussed in the preamble to the proposed rule revisions (63 FR 57356, May 21, 1998), EPA proposed changes to § 75.64(f) concerning the method of submitting quarterly reports. The proposal provided that all quarterly reports would have to be submitted to EPA by direct computer-to-computer electronic transfer via modem and EPA-provided software, unless otherwise approved by the Administrator. This requirement was to begin with the quarterly report for the first quarter of the year 2000.

Discussion: EPA received one comment (see Docket A–97–35, Item IV–D–20) which opposed the proposed requirement based on difficulty in receiving electronic transfer of quarterly reports due to technical difficulties with EPA computers which may arise due to year 2000 conversion difficulties or other technical problems relative to electronic transfer of quarterly reports at times when EPA computers may not be accessible. Concern was expressed regarding the requirement for utilities to provide proof that they attempted to transfer their reports on time but were unsuccessful due to the inability to gain access to the EPA computer system.

Based on the comment received, EPA has decided to change the electronic reporting requirement in § 75.64(f) so that beginning with the quarterly report for the first quarter of the year 2001, all quarterly reports must be submitted to EPA by direct computer-to-computer electronic transfer via modem and EPA-provided software, unless otherwise approved by the Administrator. This will ensure adequate time for all parties to address the year 2000 concerns. EPA notes that its system has already undergone testing and changes to accommodate year 2000 concerns.

J. Bias, Relative Accuracy and Availability Determinations

Background: The preamble to the proposed rule described the findings of studies performed to evaluate the provisions for the bias test, relative accuracy, and monitor availability trigger conditions as required by §§ 75.7 and 75.8. Issues concerning the bias relative accuracy, and monitor availability provisions in the core Acid Rain rules had been raised in litigation (*Environmental Defense Fund* v. *Carol M. Browner*, No. 93–120; *et al.* D.C. Cir., 1993). The purpose of these studies was to address these issues (see 63 FR 28197). The preamble of the proposed rule explained how these findings led to the Agency's proposed determinations to retain the current rule provisions concerning these matters. There were no comments objecting to the substance of the proposed determinations. Therefore, for the reasons set forth in the preamble to the proposed rule, EPA is adopting the proposed rule revisions as final, with the result that §§ 75.7 and 75.8 are removed and reserved. Moreover, since none of the issues raised concerning the bias, relative accuracy, and monitor availability provisions in the core Acid Rain rules were raised in any comments on the studies, EPA maintains that those litigation issues have been resolved.

Discussion: Two comments were received. One (see Docket A–97–56, Item IV–D–01) supported the proposed determinations. The second comment (see Docket A–97–56, Item IV–D–02) expressed concern that the bias test studies performed in response to § 75.7 did not evaluate overestimation in flow measurements. The commenter urged EPA to complete its ongoing work as quickly as possible on a separate rulemaking to resolve the commenter's flow overestimation concerns. The Agency is pursuing the separate rulemaking recommended by the commenter.

K. Appendix I—Proposed Optional Stack Flow Monitoring Methodology

Background: EPA proposed to add an F-factor/fuel flow method in Appendix I to part 75 as an excepted method to measure volumetric flow directly with a flow monitor. The Agency proposed this method based on information provided by affected utilities, and based on the assumption that the new excepted method would be used by a significant number of units as a cost-effective option to a volumetric flow monitor. This method would allow fuel flow measurement with a gas or oil flowmeter, fuel sampling data, CO_2 (or O_2) CEMS data, and F-factors to determine the flow rate of the stack gas rather than a volumetric flow monitor. The F-factor/fuel flow method would be available for use by oil-fired and gas-fired units, as defined under § 72.2, provided that they only burn natural gas and/or fuel oil. For these units, EPA believes that the proposed method would provide acceptably accurate measurements of volumetric flow. However, adoption of the proposed method would require the Agency to develop regulations imposing additional reporting and recordkeeping requirements for those units that used this option. This would also place a burden on software vendors to develop software to allow for electronic data reporting of the required data elements.

Discussion: A few commenters stated generally that they supported the Appendix I option, while two other commenters stated generally that the method should be allowed for other types of units or simplified (see Docket A–97–56, Items IV–D–9, 23, and 24, and IV–G–2 and –8). However, utilities have submitted late comments that suggest that the utilities (including those originally interested in an F-factor/fuel flow method) are in fact unlikely to use the Appendix I option at this time (see Docket A–97–56, Item IV–G–13). Based on a review of Acid Rain program databases, only about 150 units affected by the Acid Rain Program could potentially take advantage of this option. In contrast, there are a significant number of units that implement the other generally available excepted methods under Appendices D and E to Part 75 (currently, approximately 540 different units report using one or both of these methods).

As discussed above there would be substantial effort involved for EPA, utilities and software vendors to implement a new generally available option such as proposed Appendix I. As discussed in the preamble to the proposed rule, the annual savings on a per unit basis for Appendix I units are at most $10–15,000 over the measurement of volumetric flow directly with a flow monitor. The actual cost savings would be less because other provisions of today's rule revise flow monitor quality assurance requirements and significantly reduce the costs of using a flow monitor. Given the relatively small amount of savings on a per unit basis, the indication that no units would use the option at this time, and the significant burden on all interested parties in implementing a generally available option in Appendix I, the Agency has determined not to adopt Appendix I.

However, if the owner or operator of a unit decides at some time in the future to use this type of procedure for measuring flow, the designated representative of the unit may petition the Agency under § 75.66 to use this type of procedure on a case-by-case basis. In such a petition, the designated representative can reference the information used to support the proposed Appendix I procedure (see 63 FR 28113–28115, May 21, 1998, for further details on the information used to develop proposed Appendix I). The Agency will evaluate the petition on the merits at that time.

L. Subpart H—Clarifications to NO_X Mass Monitoring Requirements

Background: By notice of proposed rulemaking (NPR, proposal, or ''proposed SIP call'') (62 FR 60318, November 7, 1997) and by supplemental notice (SNPR or supplemental proposal) (63 FR 25902, May 11, 1998), EPA proposed to find that NO_X emissions from sources in 22 states and the District of Columbia, will significantly contribute to nonattainment of the 1-hour and 8-hour ozone National Ambient Air Quality Standards (NAAQS), or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind states throughout the eastern United States.

In October, 1998 (63 FR 57356, October 27, 1998), EPA finalized the proposed SIP call rulemaking. The final rule specified dates by which: (1) the affected states must submit State Implementation Plan revisions to reduce NO_X emissions to eliminate the amounts of NO_X emissions that contribute significantly to nonattainment, or that interfere with maintenance, downwind; and (2) the affected sources must implement the measures chosen by the states to achieve the required NO_X emission reductions.

The provisions of the October 27, 1998 final rule allow each state to determine the best way to achieve the necessary NO_X emission reductions. Consistent with the Ozone Transport Assessment Group's recommendation to achieve NO_X emissions decreases primarily from large stationary sources in a trading program, EPA promulgated a model rule for the implementation of such a trading program as 40 CFR part 96 (''Part 96'') in the October 27, 1998 rulemaking.

If the states should choose to create a NO_X mass trading program and to adopt the provisions of the Part 96 model rule, § 96.70 requires the monitoring and reporting of NO_X mass emissions to be done in accordance with either: (1) Subpart H of 40 CFR part 75, the Acid Rain CEM Rule (''Part 75''); or (2) for qualifying low mass-emission units, § 75.19 of Part 75. However, even if a state should choose not to participate in such a trading program, the October 27, 1998 rule still requires the monitoring provisions of Subpart H to be used by a core group of sources (large industrial boilers and turbines, and large boilers and turbines used for the generation of electricity for sale) if the NO_X mass emission reduction program for that state includes requirements to control such sources. To support these NO_X mass emission reduction programs and rulemakings, EPA promulgated both Subpart H of Part 75 and the low mass emission unit provisions in § 75.19 of Part 75 as part of the October 27, 1998 rulemaking.

In the November 7, 1997 proposed SIP Call rule, EPA would have required the affected units in a Federal or state NO_X mass emission reduction program to report NO_X emissions on a year-round basis and also to quality assure the NO_X emission data in accordance with the provisions of Part 75 on a year-round basis. However, in response to comments on the proposed rule, EPA modified Subpart H of Part 75 so that states could choose to allow sources that were not subject to the requirements of Title IV of the Clean Air Act (the Acid Rain Program) to monitor and report either on a year round basis or on an ozone season only basis. Therefore, the October 27, 1998 final rule provides for the monitoring and reporting of NO_X mass emissions either on an annual basis or during the ozone season, when this is allowed by the governing state or Federal rule.

If a state or Federal NO_X mass emission reduction program were to allow ''ozone season only'' monitoring and reporting, there would be an issue related to data quality at the start of each ozone season. To address this issue, in the October 27, 1998 final rule, EPA included a provision in § 75.74(c) of Subpart H, which requires the continuous emission monitoring systems used to provide the NO_X mass emission data to be recertified prior to the start of each ozone season.

Although Subpart H was proposed on May 21, 1998 as part of the Acid Rain CEM Rule revisions, it was finalized several months ahead of today's rulemaking, in order to support the SIP call. In the preamble to the October 27, 1998 final rule (63 FR 57467), EPA explained its intention to, where possible, make the provisions of Subpart H consistent with any other changes that EPA promulgated as a result of the May 21, 1998 proposed revisions to Part 75. EPA has re-examined the provisions of Subpart H within the context of today's final rulemaking. The Agency has found that a few minor clarifications of the regulatory language in Subpart H and the addition of one new paragraph are needed for consistency with today's final rule. The textual clarifications affect §§ 75.70(f)(1)(iv), 75.71(b) and 75.71(d)(2). The new paragraph is found at § 75.70(g)(6). In addition to these minor corrections, EPA has found that certain provisions in § 75.74(c), pertaining to sources that monitor and report data only in the ozone season, are substantially inconsistent with sections of today's final rule (particularly the new CEM data validation provisions). The Agency has also found an instance in which the text of § 75.74(c) is internally inconsistent and a second instance in which a statement in the October 27, 1998 preamble does not agree with the regulatory language in § 75.74(c). In view of these considerations, today's rulemaking revises § 75.74(c), in order to make Subpart H more consistent with the rest of Part 75 and to resolve the apparent discrepancies and inconsistencies in the text of § 75.74(c).

Discussion of Changes: As previously stated, Subpart H requires owners or operators of sources that monitor and report only during the ozone season to recertify their CEM systems prior to each ozone season. EPA put this requirement in Subpart H because the Agency believes that for sources which are not required to monitor and report on a year-round basis, substantial quality assurance testing of the CEMS prior to the ozone season is essential to validate the emission data at the beginning of the ozone season. However, in the light of today's rulemaking, the use of the word ''recertification'' in § 75.74(c) of Subpart H is regarded as inaccurate and inappropriate and does not properly communicate the Agency's intent. In § 75.20(b) of today's final rule, the term ''recertification'' has been carefully defined, so that it is limited to major changes to a CEMS which may affect its ability to accurately measure emissions. Since in most instances sources will be testing existing CEMS that have not undergone major changes, EPA believes that this is more consistent with either diagnostic testing or on-going quality assurance testing rather than recertification. Therefore, in today's final rule, all of the references in § 75.74 to ''recertification testing'' of CEMS prior to the ozone season have been replaced with terms such as ''diagnostic testing'' or ''quality assurance testing,'' which properly convey the Agency's intent and de-couple this testing from the formal administrative process associated with recertification events. Since the required pre-ozone season testing is considered to be quality assurance (QA) or diagnostic testing rather than a recertification, the Agency must specify which QA tests are to be performed. Section 75.74(c) therefore lists the specific quality assurance tests that are required prior to the ozone season. For all CEM systems, a relative accuracy test audit (RATA) is required and for all gas monitors, a linearity check is also required. After a required linearity check or RATA is passed, § 75.74(c) requires that daily calibration error tests and (if applicable) flow monitor interference checks begin to be performed. These daily assessments must then continue to be performed until the end of the ozone season.

Section 75.74(c)(5) of Subpart H, as promulgated on October 27, 1998, requires both the recording and reporting of hourly emission data prior to the current ozone season in the time interval from the date and hour that ''recertification'' testing of the CEM systems is completed through the end of the ozone season. EPA believes that most sources that choose this option would do the testing as close to the ozone season as possible. However, there may be some instances in which it would be difficult for a source to perform all of the testing in the second quarter before the beginning of the ozone season. This means that some sources for which the NO_X emission data count for compliance only during the ozone season would be required to submit additional electronic quarterly reports outside the ozone season, if they completed the pre-ozone season testing in the first or fourth calendar quarter. In view of this, EPA has reconsidered the implications of this extra reporting requirement and has concluded that it will complicate program implementation. The Agency believes that this complication is unnecessary. Therefore, in § 75.74(c)(6) of today's final rule, the Subpart H reporting provision for these sources has been revised, so that only reporting of emission data in the ozone season, from May 1 through September 30, is required. This means that in the time period from the date and hour of completion of the required pre-ozone season quality assurance testing of the CEM systems through April 30 of the current year, the owner or operator is only required to record and keep records of the hourly emission data on-site. The only pre-ozone season data that must be reported are the results of daily calibration error checks and flow monitor interference checks performed in the time period from April 1 through April 30 and the results of any linearity checks, RATAs, fuel flow meter tests and fuel sampling performed outside of the ozone season for purposes of compliance with Subpart H. This will provide the regulatory agencies with added assurance that the CEMS data are quality-assured at the start of the ozone season and will enable the agencies to have a limited pre-ozone season electronic auditing capability. The requirement to report the results of the daily assessments for the month of April is not considered burdensome because April is in the second calendar quarter, which is one of the two reporting quarters for the affected sources. In fact, some affected sources may prefer to report data for April, because it may be easier to generate an electronic quarterly report for the entire second calendar quarter, rather than just for the months of May and June. Therefore, § 75.74(c)(6) of today's final rule gives the owner or operator the option to report unit operating data and emission data for the month of April.

In reviewing the missing data provisions of Subpart H, EPA found a discrepancy between the Agency's stated intent in the preamble to the October 27, 1998 final rule and the regulatory language in § 75.74(c)(6)(i). The preamble states that ''[h]istorical lookback periods for missing data only need to include data from the ozone season'' (63 FR 57483, October 27, 1998). However, the rule language in § 75.74(c)(6)(i) does not state this explicitly, and could be misinterpreted. The rule language states that all ''quality assured data, in accordance with paragraph (c)(2) or (c)(3) of this section'' are to be used for missing data purposes. This could be interpreted as meaning that the data recorded outside the ozone season, in the time period between completion of the pre-ozone season quality assurance testing of the CEM systems and May 1, are to be included in the missing data lookback periods. This is not what EPA intends; rather, the statement cited above from the October 27, 1998 preamble accurately reflects the Agency's position. Therefore, § 75.74(c)(7) of today's rule clearly states that for purposes of missing data substitution, only data recorded during the ozone season will be used for the historical missing data lookback periods.

Finally, EPA has examined the quality assurance provisions of Subpart H in view of the many substantial changes to the quality assurance and data validation provisions of Part 75 in today's rulemaking. The Agency has concluded that, in light of the many changes that have been made to Part 75, the general references in Subpart H to the quality assurance provisions in § 75.21 and appendix B to Part 75 and references to the data validation procedures in § 75.20 could be clarified to make the requirements easier to understand, particularly for sources that report data only during the ozone season. There are several reasons for this.

First, sections 2.2.4 and 2.3.3 in appendix B of today's final rule provide ''grace periods'' in which late or missed QA tests can be completed. For linearity checks, the grace period is 168 unit operating hours after the end of the quarter in which the test is due. For RATAs, the grace period is 720 unit operating hours after the end of the quarter in which the RATA is due. Because the grace periods in Part 75 are in terms of unit operating hours, they can sometimes extend for more than one calendar quarter beyond the quarter in which the QA test was due (particularly for infrequently-operated or seasonally-operated units). Consequently, the Part 75 grace period provisions in appendix B are considered to be inappropriate for sources that report emissions data only during the ozone season. Without a complete record of unit operation for each year, the regulatory agency will be unable to determine whether the required QA tests have been completed within the allotted grace period.

Second, § 75.20(b)(3) of today's final rule provides ''conditional'' data validation procedures for CEMS recertifications. These provisions allow a probationary period following a recertification event, during which data from a CEMS are assigned a ''conditionally valid'' status. Provided that all recertification tests are passed within the probationary period, with no test failures, § 75.20(b)(3) allows the conditionally valid data to be reported as quality-assured. Today's rule also allows these data validation procedures to be used for routine linearity checks and RATAs, in cases where significant repair, adjustment or reprogramming of the CEMS is done prior to the QA test. The maximum allowable length of the probationary period is 168 unit operating hours for a linearity check and 720 unit operating hours for a RATA. Once again, because these probationary periods are in terms of unit operating hours, they can extend outside the current calendar quarter, into the next quarter and possibly beyond the next quarter. Therefore, for sources that report only during the ozone season, some restrictions must be placed on the use of the conditional data validation procedures in § 75.20(b)(3).

In view of the above considerations, EPA has revised Subpart H to make it clear which of the Part 75 QA and data validation provisions are applicable to sources that report only in the ozone season and which provisions are inapplicable. The Agency has replaced the general references in Subpart H to the quality assurance provisions of § 75.21 and appendix B and the references to the provisions of § 75.20 with specific language that delineates the exact QA tests required during each ozone season. Section 75.74(c)(3) of today's rule also contains specific data validation provisions for sources that report only during the ozone season. To the extent possible, these QA and data validation provisions have been made the same as or similar to the requirements for sources that report data on a year-round basis. However, as necessary, special provisions have been added to § 75.74(c) to address the differences between year-round reporters and sources that report only during the ozone season. EPA believes that these revisions to Subpart H will help to achieve consistency in the implementation of state and Federal NO_X mass emission reduction programs and will help to ensure the quality of the reported data.

IV. Administrative Requirements

A. Public Docket

EPA has established Docket A–97–35 for the regulations. The docket is an organized and complete file of all the information submitted to, or otherwise considered by, EPA in the development of today's final rule. The principal purposes of the docket are: (1) to allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process; and (2) to serve as the record in case of judicial review. The docket is available for public inspection at EPA's Air Docket, which is listed under the **ADDRESSES** section of this notice.

B. Executive Order 12866

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

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

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

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

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

This rule is not expected to have an annual effect on the economy of $100 million or more.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a ''significant regulatory action'' due to its policy implications. Therefore, the rule was submitted to OMB for review. Any written comments from OMB and any EPA response to those comments are included in the public docket for this proposal. The docket is available for public inspection at EPA's Air Docket Section, which is listed in the **ADDRESSES** portion of this preamble.

C. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Section 205 of the UMRA generally requires that, before promulgating rules for which a written statement is needed, EPA must identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

This rule is not expected to result in expenditures of more than $100 million in any one year and therefore is not subject to section 202 of the UMRA. Although the rule is not expected to significantly or uniquely affect small governments, the Agency notified all potentially affected small governments that own or operate units potentially affected by the rule in order to assure that they had the opportunity to have meaningful and timely input on the rule. EPA will continue to use its outreach efforts related to part 75 implementation, including a policy manual that is generally updated on a quarterly basis, to inform, educate, and advise all potentially impacted small governments about compliance with part 75.

EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan.

D. Executive Order 12875

Under Executive Order 12875, EPA may not issue a regulation that is not required by statute and that creates a mandate upon a State, local or tribal government, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by those governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 12875 requires EPA to provide to the Office of Management and Budget a description of the extent of EPA's prior consultation with representatives of affected State, local and tribal governments, the nature of their concerns, copies of any written communications from the governments, and a statement supporting the need to issue the regulation. In addition, Executive Order 12875 requires EPA to develop an effective process permitting elected officials and other representatives of State, local and tribal governments ''to provide meaningful and timely input in the development of regulatory proposals containing significant unfunded mandates.''

EPA has concluded that this rule will create a mandate on local and tribal governments and that the Federal government will not provide the funds necessary to pay the direct costs incurred by the local and tribal governments in complying with the mandate. In developing this rule, EPA consulted with local and tribal governments to enable them to provide meaningful and timely input in the development of this rule. Only local or tribal governments that own sources affected by Acid Rain would be affected by this rulemaking. The governments that own an Acid Rain affected source were contacted when the proposed rule was signed and informed of their right to comment on the proposal. EPA received a few comment letters from municipal utilities; these letters contained support for many elements of the rule, as well as concerns with certain provisions. The Agency has attempted to include changes to the proposed rule revisions based on these and other comments wherever possible consistent with the purpose and intent of the rule revisions, and to the extent justified by the commenters. See section III of this preamble and the response to comments document included in the docket for this rulemaking for the Agency's responses to the specific comments raised. EPA also notes generally that these sources already have to comply with part 75. Today's rule adds more compliance flexibility and may reduce the compliance costs for some of the sources owned by local and tribal governments.

E. Executive Order 13084

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments, or EPA consults with those governments. If EPA complies by consulting, Executive Order 13084 requires EPA to provide the Office of Management and Budget, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected officials and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Today's rule does not significantly or uniquely affect the communities of Indian tribal governments. Only tribal governments that own sources affected by the Acid Rain Program are affected by this rulemaking. As noted above in section IV.D. of this preamble, today's rule adds compliance flexibility and may reduce compliance costs for any tribal governments that own or operate affected sources. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

F. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* An Information Collection Request (ICR) document has been prepared by EPA (ICR No. 1633.12), and a copy may be obtained from Sandy Farmer, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M Street, SW, Washington, DC 20460, by calling (202) 260–2740, or via the Internet at www.epa.gov/icr. The information requirements are not effective until OMB approves them.

Currently, all affected facilities are required to keep records and submit electronic quarterly reports under the provisions of part 75. The revisions to the rule include several new options for compliance with part 75 which have been requested by owners or operators of affected facilities. To implement these options, EPA will have to modify the existing recordkeeping and reporting requirements. In some circumstances, these changes will result in significant reductions in the reporting and recordkeeping burdens or costs for some units (such as low mass emissions units). However, these changes will require modifications to the software used to generate electronic reports. In addition, there will be some increased burden or costs for certain units to fulfill the new quality assurance procedures contained in this rule. Finally, several other technical revisions to the existing reporting and recordkeeping requirements have been adopted to clarify existing provisions or to facilitate reporting for other regulatory programs in the context of Acid Rain Program reporting. Although these one-time software changes will increase the short-term burdens on sources under the Acid Rain Program, the changes should reduce a source's overall long-term burden by streamlining the source's reporting obligations under both the Acid Rain Program and other parts of the Act.

The average annual projected hour burden is 1,225,633, which is based on an estimated average burden of approximately 421 hours per response, quarterly reporting frequency, and an estimated 728 likely respondents (on a per facility basis). The projected annual cost burden resulting from the collection of information is $192,483,642, which includes a total projected capital and start-up average annualized cost of $92,131,857 (for monitoring equipment/software), total projected fuel sampling and analysis average annual cost of $581,100, and a total projected operation and maintenance average annual cost (which includes purchase of testing contractor services) of $41,398,000. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, 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 purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

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

G. Regulatory Flexibility

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

Today's revisions to part 75 result in a net cost reduction to facilities affected by the Acid Rain Program, including small entities. Most importantly, the changes to Appendix D will significantly reduce the cost of complying with part 75 for oil-and gas-fired units, many of which are owned or operated by small entities.

Accordingly, considering all of the above information, EPA concludes that this rule will not have a significant economic impact on a substantial number of small entities.

H. Submission to Congress and the General Accounting Office

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 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 General Accounting Office prior to publication of the rule in today's **Federal Register**. This rule is not a ''major rule'' as defined by U.S.C. 804(2).

I. Executive Order 13045

This final rule is not subject to Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), because it does not involve decisions on environmental health risks or safety risks that may disproportionately affect children.

J. National Technology Transfer and Advancement Act

Section 12(d) of National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Pub L. 104–113, section 12(d) (15 U.S.C. 272 note), directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices, etc.) that are developed or adopted by voluntary consensus standards bodies. The NTTAA requires EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

Part 75 already incorporates a number of voluntary consensus standards. In addition, today's rule includes incorporation on two voluntary consensus standards, in response to comments submitted on the proposed part 75 rulemaking. First, ASTM D5373–93 ''Standard Methods for

Instrumental Determination of Carbon, Hydrogen and Nitrogen in laboratory samples of Coal and Coke.'' This standard is incorporated by reference for use under section 2.1 of Appendix G to part 75. Second, API Sections 2, 3 and 5 from Chapter 4 of the Manual of Petroleum Standards, October 1988 edition. This standard is incorporated by reference for use under section 2.1.5.1 of Appendix D to part 75.

Consistent with the Agency's Performance Based Measurement System, part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth 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. 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 in advance before they may be used under part 75.

List of Subjects

40 CFR Part 72

Environmental protection, Acid rain, Air pollution control, Electric utilities, Nitrogen oxides, Sulfur oxides.

40 CFR Part 75

Environmental protection, Air pollution control, Carbon dioxide, Continuous emission monitoring, Electric utilities, Incorporation by reference, Nitrogen oxides, Reporting and recordkeeping, Sulfur dioxide.

Dated: April 1, 1999.

Carol M. Browner,

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 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 correcting the definition of ''diesel fuel;'' by revising the definitions of ''calibration gas,'' ''coal-fired'' (introductory text only), ''gas-fired,'' ''natural gas,'' ''pipeline natural gas,'' ''span,'' ''stationary gas turbine,'' and ''zero air material;'' by adding, in alphabetical order, new definitions for ''conditionally valid data,'' ''EPA protocol gas,'' ''fuel flowmeter QA operating quarter,'' ''gas manufacturer's intermediate standard,'' ''probationary calibration error test,'' ''QA operating quarter,'' ''research gas mixture'' ''stack operating hour,'' ''standard reference material-equivalent compressed gas primary reference material (SRM-equivalent PRM),'' and ''very low sulfur fuel;'' by revising paragraphs (1) introductory text, (1)(ii) and (2) of the definition of ''oil-fired'' and paragraph (2) of the definition of ''peaking unit;'' by adding a paragraph (3) to the definition of ''peaking unit;'' and by removing the definition of ''protocol 1 gas'' and to read as follows:

§ 72.2 Definitions.

* * * * *

Calibration gas means:

(1) A standard reference material;

(2) A standard reference material-equivalent compressed gas primary reference material;

(3) A NIST traceable reference material;

(4) NIST/EPA-approved certified reference materials;

(5) A gas manufacturer's intermediate standard;

(6) An EPA protocol gas;

(7) Zero air material; or

(8) A research gas mixture.

* * * * *

Coal-fired means the combustion of fuel consisting of coal or any coal-derived fuel (except a coal-derived gaseous fuel that meets the definition of ''very low sulfur fuel'' in this section), alone or in combination with any other fuel, where:

* * * * *

Conditionally valid data means data from a continuous monitoring system that are not quality assured, but which may become quality assured if certain conditions are met. Examples of data that may qualify as conditionally valid are: data recorded by an uncertified monitoring system prior to its initial certification; or data recorded by a certified monitoring system following a significant change to the system that may affect its ability to accurately measure and record emissions. A monitoring system must pass a probationary calibration error test, in accordance with section 2.1.1 of appendix B to part 75 of this chapter, to initiate the conditionally valid data status. In order for conditionally valid emission data to become quality assured, one or more quality assurance tests or diagnostic tests must be passed within a specified time period in accordance with § 75.20(b)(3).

* * * * *

Diesel fuel means a low sulfur fuel oil of grades 1–D or 2–D, as defined by the American Society for Testing and Materials standard ASTM D975–91, ''Standard Specification for Diesel Fuel Oils,'' grades 1–GT or 2–GT, as defined by ASTM D2880–90a, ''Standard Specification for Gas Turbine Fuel Oils,'' or grades 1 or 2, as defined by ASTM D396–90a, ''Standard Specification for Fuel Oils'' (incorporated by reference in § 72.13).

* * * * *

EPA protocol gas means a calibration gas mixture prepared and analyzed according to section 2 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121 or such revised procedure as approved by the Administrator.

* * * * *

Fuel flowmeter QA operating quarter means a unit operating quarter in which the unit combusts the fuel measured by the fuel flowmeter for at least 168 unit operating hours (as defined in this section) or more.

* * * * *

Gas-fired means:

(1) For all purposes under the Acid Rain Program, except for part 75 of this chapter, the combustion of:

(i) Natural gas or other gaseous fuel (including coal-derived gaseous fuel), for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years; and

(ii) Any fuel, except coal or solid or liquid coal-derived fuel, for the remaining heat input, if any.

(2) For purposes of part 75 of this chapter, the combustion of:

(i) Natural gas or other gaseous fuel (including coal-derived gaseous fuel) for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years; and

(ii) Fuel oil, for the remaining heat input, if any.

(3) For purposes of part 75 of this chapter, a unit may initially qualify as gas-fired if the designated representative demonstrates to the satisfaction of the Administrator that the requirements of paragraph (2) of this definition are met, or will in the future be met, through one of the following submissions:

(i) For a unit for which a monitoring plan has not been submitted under § 75.62 of this chapter, the designated representative submits either:

(A) Fuel usage data for the unit for the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under § 75.62; or

(B) If a unit does not have fuel usage data for one or more of the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under § 75.62, the unit's designated fuel usage; all available fuel usage data (including the percentage of the unit's heat input derived from the combustion of gaseous fuels), beginning with the date on which the unit commenced commercial operation; and the unit's projected fuel usage.

(ii) For a unit for which a monitoring plan has already been submitted under § 75.62, that has not qualified as gas-fired under paragraph (3)(i) of this definition, and whose fuel usage changes, the designated representative submits either:

(A) Three calendar years of data following the change in the unit's fuel usage, showing that no less than 90.0 percent of the unit's average annual heat input during the previous three calendar years, and no less than 85.0 percent of the unit's annual heat input during any one of the previous three calendar years, is from the combustion of gaseous fuels and the remaining heat input is from the combustion of fuel oil; or

(B) A minimum of 720 hours of unit operating data following the change in the unit's fuel usage, showing that no less than 90.0 percent of the unit's heat input is from the combustion of gaseous fuels and the remaining heat input is from the combustion of fuel oil, and a statement that this changed pattern of fuel usage is considered permanent and is projected to continue for the foreseeable future.

(iii) If a unit qualifies as gas-fired under paragraph (3)(i) or (ii) of this definition, the unit is classified as gas-fired as of the date of the submission under such paragraph.

(4) For purposes of part 75 of this chapter, a unit that initially qualifies as gas-fired under paragraph (3)(i) or (ii) of this definition must meet the criteria in paragraph (2) of this definition each year in order to continue to qualify as gas-fired. If such a unit combusts only gaseous fuel and fuel oil but fails to meet such criteria for a given year, the unit no longer qualifies as gas-fired starting January 1 of the year after the first year for which the criteria are not met. If such a unit combusts fuel other than gaseous fuel or fuel oil and fails to meet such criteria in a given year, the unit no longer qualifies as gas-fired starting the day after the first day for which the criteria are not met. If a unit failing to meet the criteria in paragraph (2) of this definition initially qualified as a gas-fired unit under paragraph (3) of this definition, the unit may qualify as a gas-fired unit for a subsequent year only if the designated representative submits the data specified in paragraph (3)(ii)(A) of this definition.

* * * * *

Gas manufacturer's intermediate standard (GMIS) means a compressed gas calibration standard that has been assayed and certified by direct comparison to a standard reference material (SRM), an SRM-equivalent PRM, a NIST/EPA-approved certified reference material (CRM), or a NIST traceable reference material (NTRM), in accordance with section 2.1.2.1 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121.

* * * * *

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. Natural gas contains 1.0 grain or less of hydrogen sulfide per 100 standard cubic feet and the hydrogen sulfide constitutes more than 50% (by weight) of the total sulfur in the gas fuel. Additionally, natural gas must meet either be composed of at least 70% methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

* * * * *

Oil-fired means:

(1) For all purposes under the Acid Rain Program, except part 75 of this chapter, the combustion of:

(i) * * *

(ii) Any solid, liquid or gaseous fuel (including coal-derived gaseous fuel), other than coal or any other coal-derived solid or liquid fuel, for the remaining heat input, if any.

(2) For purposes of part 75 of this chapter, combustion of only fuel oil and gaseous fuels, provided that the unit involved does not meet the definition of gas-fired.

* * * * *

Peaking unit means:

* * * * *

(2) For purposes of part 75 of this chapter, a unit may initially qualify as a peaking unit if the designated representative demonstrates to the satisfaction of the Administrator that the requirements of paragraph (1) of this definition are met, or will in the future be met, through one of the following submissions:

(i) For a unit for which a monitoring plan has not been submitted under § 75.62, the designated representative submits either:

(A) Capacity factor data for the unit for the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under § 75.62; or

(B) If a unit does not have capacity factor data for one or more of the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under § 75.62, all available capacity factor data, beginning with the date on which the unit commenced commercial operation; and projected capacity factor data.

(ii) For a unit for which a monitoring plan has already been submitted under § 75.62, that has not qualified as a peaking unit under paragraph (2)(i) of this definition, and where capacity factor changes, the designated representative submits either:

(A) Three calendar years of data following the change in the unit's capacity factor showing an average capacity factor of no more than 10.0 percent during the three previous calendar years and a capacity factor of no more than 20.0 percent in each of those calendar years; or

(B) One calendar year of data following the change in the unit's capacity factor showing a capacity factor of no more than 10.0 percent and a statement that this changed pattern of operation resulting in a capacity factor less than 10.0 percent is considered permanent and is projected to continue for the foreseeable future.

(3) For purposes of part 75 of this chapter, a unit that initially qualifies as a peaking unit must meet the criteria in paragraph (1) of this definition each year in order to continue to qualify as a peaking unit. If such a unit fails to meet such criteria for a given year, the unit no longer qualifies as a peaking unit starting January 1 of the year after the year for which the criteria are not met. If a unit failing to meet the criteria in paragraph (1) of this definition initially qualified as a peaking unit under paragraph (2) of this definition, the unit may qualify as a peaking unit for a subsequent year only if the designated representative submits the data specified in paragraph (2)(ii)(A) of this definition.

* * * * *

Pipeline natural gas means natural gas, as defined in this section, that is provided by a supplier through a pipeline and that contains 0.3 grains or less of hydrogen sulfide per 100 standard cubic feet and the hydrogen sulfide in content of the gas constitutes at least 50% (by weight) of the total sulfur in the fuel;

* * * * *

Probationary calibration error test means an on-line calibration error test performed in accordance with section 2.1.1 of appendix B to part 75 of this chapter that is used to initiate a conditionally valid data period.

* * * * *

QA operating quarter means a calendar quarter in which there are at least 168 unit operating hours (as defined in this section) or, for a common stack or bypass stack, a calendar quarter in which there are at least 168 stack operating hours (as defined in this section).

* * * * *

Research gas mixture (RGM) means a calibration gas mixture developed by agreement of a requestor and NIST that NIST analyzes and certifies as ''NIST traceable.'' RGMs may have concentrations different from those of standard reference materials.

* * * * *

Span means the highest pollutant or diluent concentration or flow rate that a monitor component is required to be capable of measuring under part 75 of this chapter.

* * * * *

Stack operating hour means any hour (or fraction of an hour) during which flue gases flow through a common stack or bypass stack.

* * * * *

Standard reference material-equivalent compressed gas primary reference material (SRM-equivalent PRM) means those gas mixtures listed in a declaration of equivalence in accordance with section 2.1.2 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121.

* * * * *

Stationary gas turbine means a turbine that is not self-propelled and that combusts natural gas, other gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas, or fuel oil in order to heat inlet combustion air and thereby turn a turbine in addition to or instead of producing steam or heating water.

* * * * *

Very low sulfur fuel means either:

(1) A fuel with a total sulfur content no greater than 0.05 percent sulfur by weight;

(2) Natural gas or pipeline natural gas, as defined in this section; or

(3) Any gaseous fuel with a total sulfur content no greater than 20 grains of sulfur per 100 standard cubic feet.

* * * * *

Zero air material means either:

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

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

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

(4) A multicomponent mixture certified by the supplier of the mixture that the concentration of the component being zeroed is less than or equal to the applicable concentration specified in paragraph (1) of this definition, and that the mixture's other components do not interfere with the CEM readings.

3. Section 72.3 is amended by adding, in alphabetical order, new acronyms for CEMS, kacfm, kscfh, NIST and RATA to read as follows:

§ 72.3 Measurements, abbreviations, and acronyms.

* * * * *

CEMS—continuous emission monitoring system.

* * * * *

kacfm—thousands of cubic feet per minute at actual conditions.

kscfh—thousands of cubic feet per hour at standard conditions.

* * * * *

NIST—National Institute of Standards and Technology.

* * * * *

RATA—relative accuracy test audit.

* * * * *

§ 72.6 [Amended]

4. Section 72.6 is amended by removing from paragraph (b)(1) the word ''operation'' and adding, in its place, the words ''commercial operation.''

5. Section 72.90 is amended by revising paragraph (c)(3) to read as follows:

§ 72.90 Annual compliance certification report.

* * * * *

(c) * * *

(3) Whether all the emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditionally valid data, as defined in § 72.2, were reported in the quarterly report. If conditionally valid data were reported, the owner or operator shall indicate whether the status of all conditionally valid data has been resolved and all necessary quarterly report resubmissions have been made.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

6. The authority citation for part 75 is revised to read as follows:

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

Subpart A—General

7. Section 75.4 is amended by revising the last sentence of paragraph (a) introductory text, revising the first sentence of paragraph (d) introductory text, revising paragraph (d)(1), adding a new sentence to the beginning of paragraph (g) introductory text, and adding a new paragraph (i) to read as follows:

§ 75.4 Compliance dates.

(a) * * * In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all monitoring systems required by this part for monitoring SO_2, NO_X, CO_2, opacity, moisture and volumetric flow are installed and that all certification tests are completed no later than the following dates (except as provided in paragraphs (d) through (i) of this section):

* * * * *

(d) In accordance with § 75.20, the owner or operator of an existing unit that is shutdown and is not yet operating by the applicable dates listed in paragraph (a) of this section, or an existing unit which has been placed in long-term cold storage after having previously reported emissions data in accordance with this part, shall ensure that all monitoring systems required under this part for monitoring of SO_2, NO_X, CO_2, opacity, and volumetric flow are installed and all certification tests are completed no later than the earlier of 45 unit operating days or 180 calendar days after the date that the unit recommences commercial operation of the affected unit, notice of which date shall be provided under subpart G of this part. * * *

(1) The maximum potential concentration of SO_2, the maximum potential NO_X emission rate, as defined in section 2.1.2.1 of appendix A to this part, the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, or the maximum potential CO_2 concentration, as defined in section 2.1.3.1 of appendix A to this part;

* * * * *

(g) The provisions of this paragraph shall apply unless an owner or operator is exempt from certifying a fuel flowmeter for use during combustion of emergency fuel under section 2.1.4.3 of appendix D to this part, in which circumstance the provisions of section 2.1.4.3 of appendix D shall apply. * * *

* * * * *

(i) In accordance with § 75.20, the owner or operator of each affected unit at which SO_2 concentration is measured on a dry basis or at which moisture corrections are required to account for CO_2 emissions, NO_X emission rate in lb/mmBtu, heat input, or NO_X mass emissions for units in a NO_X mass reduction program, shall ensure that the continuous moisture monitoring system required by this part is installed and that all applicable initial certification tests required under § 75.20(c)(5), (c)(6), or (c)(7) for the continuous moisture monitoring system are completed no later than the following dates:

(1) April 1, 2000, for a unit that is existing and has commenced commercial operation by January 2, 2000; or

(2) For a new affected unit which has not commenced commercial operation by January 2, 2000, no later than 90 days 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, no later than the earlier of 45 unit operating days or 180 calendar days after the date that the unit recommences commercial operation.

8. Section 75.5 is amended by revising paragraphs (b), (d), and (f)(2) to read as follows:

§ 75.5 Prohibitions.

* * * * *

(b) No owner or operator of an affected unit shall operate the unit without complying with the requirements of §§ 75.2 through 75.75 and appendices A through G to this part.

* * * * *

(d) No owner or operator of an affected unit shall operate the unit so as to discharge, or allow to be discharged, emissions of SO_2, NO_X or CO_2 to the atmosphere without accounting for all such emissions in accordance with the provisions of §§ 75.10 through 75.19.

* * * * *

(f) * * *

(2) The owner or operator is monitoring emissions from the unit with another certified monitoring system or an excepted methodology approved by the Administrator for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or

* * * * *

9. Section 75.6 is amended by revising paragraphs (a)(13), (a)(31), (a)(38), (a)(39), (b), (c), (e)(1) and (e)(2); by redesignating paragraph (a)(40) as paragraph (a)(41); and by adding new paragraphs (a)(40) and (f)(3) to read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(a) * * *

(13) ASTM D1826–88, Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, for appendices D and F to this part.

* * * * *

(31) ASTM D3588–91, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels, for appendices D and F to this part.

* * * * *

(38) ASTM D4891–89, Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, for appendices D and F to this part.

(39) ASTM D5291–92, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, for appendices F and G to this part.

(40) ASTM D5373–93, ''Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke,'' for appendix G to this part.

(41) * * *

(b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, Box 2350, Fairfield, NJ 07007–2350.

(1) ASME MFC–3M–1989 with September 1990 Errata, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, for appendix D of this part.

(2) ASME MFC–4M–1986 (Reaffirmed 1990), Measurement of Gas Flow by Turbine Meters, for appendix D of this part.

(3) ASME-MFC–5M–1985, Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, for appendix D of this part.

(4) ASME MFC–6M–1987 with June 1987 Errata, Measurement of Fluid Flow in Pipes Using Vortex Flow Meters, for appendix D of this part.

(5) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, for appendix D of this part.

(6) ASME MFC–9M–1988 with December 1989 Errata, Measurement of Liquid Flow in Closed Conduits by Weighing Method, for appendix D of this part.

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 11 W. 42nd Street, New York NY 10036: ISO 8316: 1987(E) Measurement of Liquid Flow in Closed Conduits-Method by Collection of the Liquid in a Volumetric Tank, for appendices D and E of this part.

* * * * *

(e) * * *

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition) and Part 3: Natural Gas Applications (August 1992 Edition), for appendices D and E of this part.

(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April, 1996), for appendix D to this part.

(f) * * *

(3) American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' Section 3, ''Small Volume Provers,'' and Section 5, ''Master-Meter Provers,'' from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993), for appendix D to this part.

10. Section 75.7 is removed and reserved.

§ 75.7 [Removed and Reserved]

11. Section 75.8 is removed and reserved.

§ 75.8 [Removed and Reserved]

Subpart B —Monitoring Provisions

12. Section 75.10 is amended by revising paragraphs (d)(3) and (f) to read as follows:

§ 75.10 General operating requirements.

* * * * *

(d) * * *

(3) Failure of an SO_2, CO_2, or O_2 pollutant concentration monitor, flow monitor, or NO_X continuous emission monitoring system to acquire the minimum number of data points for calculation of an hourly average in paragraph (d)(1) of this section shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. An hourly average NO_X or SO_2 emission rate in lb/mmBtu is valid only if the minimum number of data points is acquired by both the pollutant concentration monitor (NO_X or SO_2) and the diluent monitor (O_2 or CO_2). For a moisture monitoring system consisting of one or more oxygen analyzers capable of measuring O_2 on a wet-basis and a dry-basis, an hourly average percent moisture value is valid only if the minimum number of data points is acquired for both the wet-and dry-basis measurements. Except for SO_2 emission rate data in lb/mmBtu, if a valid hour of data is not obtained, the owner or operator shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in subpart D of this part.

* * * * *

(f) *Minimum measurement capability requirement.* The owner or operator shall ensure that each continuous emission monitoring system and component thereof is capable of accurately measuring, recording, and reporting data, and shall not incur an exceedance of the full scale range, except as provided in sections 2.1.1.5, 2.1.2.5, and 2.1.4.3 of appendix A to this part.

* * * * *

13. Section 75.11 is amended by revising paragraphs (a), (b), (d)(1), (d)(2), (e) introductory text, (e)(1), (e)(2), (e)(3) introductory text, (e)(3)(ii), (e)(3)(iv), and by removing paragraph (e)(4) to read as follows:

§ 75.11 Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors).

(a) *Coal-fired units.* The owner or operator shall meet the general operating requirements in § 75.10 for an SO_2 continuous emission monitoring system and a flow monitoring system for each affected coal-fired unit while the unit is combusting coal and/or any other fuel, except as provided in paragraph (e) of this section, in § 75.16, and in subpart E of this part. During hours in which only gaseous fuel is combusted in the unit, the owner or operator shall comply with the applicable provisions of paragraph (e)(1), (e)(2), or (e)(3) of this section.

(b) *Moisture correction.* Where SO_2 concentration is measured on a dry basis, the owner or operator shall either:

(1) Report the appropriate fuel-specific default moisture value for each unit operating hour, selected from among the following: 3.0%, for anthracite coal; 6.0% for bituminous coal; 8.0% for sub-bituminous coal; 11.0% for lignite coal; 13.0% for wood; or

(2) Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating SO_2 mass emissions (in lb/hr) using the procedures in appendix F to this part. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, i.e., a psychometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet-and dry-basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

* * * * *

(d) * * *

(1) By meeting the general operating requirements in § 75.10 for an SO_2 continuous emission monitoring system and flow monitoring system. If this option is selected, the owner or operator shall comply with the applicable provisions in paragraph (e)(1), (e)(2), or (e)(3) of this section during hours in which the unit combusts only gaseous fuel;

(2) By providing other information satisfactory to the Administrator using the applicable procedures specified in appendix D to this part for estimating hourly SO_2 mass emissions; or

* * * * *

(e) *Units with SO_2 continuous emission monitoring systems during the combustion of gaseous fuel.* The owner or operator of an affected unit with an SO_2 continuous emission monitoring system shall, during any hour in which the unit combusts only gaseous fuel, determine SO_2 emissions in accordance with paragraph (e)(1), (e)(2) or (e)(3) of this section, as applicable.

(1) If the gaseous fuel meets the definition of ''pipeline natural gas'' or ''natural gas'' in § 72.2 of this chapter, the owner or operator may, in lieu of operating and recording data from the SO_2 monitoring system, determine SO_2 emissions by using Equation F–23 in appendix F to this part. Substitute into Equation F–23 the hourly heat input, calculated using a certified flow monitoring system and a certified diluent monitor, in conjunction with the appropriate default SO_2 emission rate from section 2.3.1.1 or 2.3.2.1.1 of appendix D to this part, and Equation D–5 in appendix D to this part. When this option is chosen, the owner or operator shall perform the necessary data acquisition and handling system tests under § 75.20(c), and shall meet all quality control and quality assurance requirements in appendix B to this part for the flow monitor and the diluent monitor.

(2) The owner or operator may, in lieu of operating and recording data from the SO_2 monitoring system, determine SO_2 emissions by certifying an excepted monitoring system in accordance with § 75.20 and appendix D to this part, following the applicable fuel sampling and analysis procedures in section 2.3 of appendix D to this part, meeting the recordkeeping requirements of § 75.55 or § 75.58, as applicable, and meeting all quality control and quality assurance requirements for fuel flowmeters in appendix D to this part. If this compliance option is selected, the hourly unit heat input reported under § 75.54(b)(5) or § 75.57(b)(5), as applicable, shall be determined using a certified flow monitoring system and a certified diluent monitor, in accordance with the procedures in section 5.2 of appendix F to this part. The flow monitor and diluent monitor shall meet all of the applicable quality control and quality assurance requirements of appendix B to this part.

(3) The owner or operator may determine SO_2 mass emissions by using a certified SO_2 continuous monitoring system, in conjunction with a certified flow rate monitoring system. However, if the unit burns any gaseous fuel that is very low sulfur fuel (as defined in § 72.2 of this chapter), then on and after April 1, 2000, the SO_2 monitoring

system shall be subject to the following quality assurance provisions when the very low sulfur fuel is combusted. Prior to April 1, 2000, the owner or operator may comply with these provisions.

* * * * *

(ii) EPA recommends that the calibration response of the SO_2 monitoring system be adjusted, either automatically or manually, in accordance with the procedures for routine calibration adjustments in section 2.1.3 of appendix B to this part, whenever the zero-level calibration response during a required daily calibration error test exceeds the applicable performance specification of the instrument in section 3.1 of appendix A to this part (i.e., ±2.5 percent of the span value or ±5 ppm, whichever is less restrictive).

* * * * *

(iv) In accordance with the requirements of section 2.1.1.2 of appendix A to this part, for units that sometimes burn gaseous fuel that is very low sulfur fuel (as defined in § 72.2 of this chapter) and at other times burn higher sulfur fuel(s) such as coal or oil, a second low-scale SO_2 measurement range is not required when the very low sulfur gaseous fuel is combusted. For units that burn only gaseous fuel that is very low sulfur fuel and burn no other type(s) of fuel(s), the owner or operator shall set the span of the SO_2 monitoring system to a value no greater than 200 ppm.

* * * * *

14. Section 75.12 is amended by revising the first sentence in paragraph (a); by redesignating existing paragraphs (b), (c), (d) and (e) as paragraphs (c), (d), (e) and (f), respectively; by adding new paragraph (b); and by revising the newly designated paragraph (c) to read as follows:

§ 75.12 Specific provisions for monitoring NO_X emission rate (NO_X and diluent gas monitors).

(a) *Coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units.* The owner or operator shall meet the general operating requirements in § 75.10 of this part for a NO_X continuous emission monitoring system for each affected coal-fired unit, gas-fired nonpeaking unit, or oil-fired nonpeaking unit, except as provided in paragraph (d) of this section, § 75.17, and subpart E of this part. * * *

(b) *Moisture correction.* If a correction for the stack gas moisture content is needed to properly calculate the NO_X emission rate in lb/mmBtu, e.g., if the NO_X pollutant concentration monitor measures on a different moisture basis from the diluent monitor, the owner or operator shall either report a fuel-specific default moisture value for each unit operating hour, as provided in § 75.11(b)(1), or shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in § 75.11(b)(2). Notwithstanding this requirement, if Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to measure NO_X emission rate, the following fuel-specific default moisture percentages shall be used in lieu of the default values specified in § 75.11(b)(1): 5.0%, for anthracite coal; 8.0% for bituminous coal; 12.0% for sub-bituminous coal; 13.0% for lignite coal; and 15.0% for wood.

(c) *Determination of NO_X emission rate.* The owner or operator shall calculate hourly, quarterly, and annual NO_X emission rates (in lb/mmBtu) by combining the NO_X concentration (in ppm), diluent concentration (in percent O_2 or CO_2), and percent moisture (if applicable) measurements according to the procedures in appendix F to this part.

* * * * *

15. Section 75.13 is amended by revising paragraphs (a) and (c) to read as follows:

§ 75.13 Specific provisions for monitoring CO_2 emissions.

(a) *CO_2 continuous emission monitoring system.* If the owner or operator chooses to use the continuous emission monitoring method, then the owner or operator shall meet the general operating requirements in § 75.10 for a CO_2 continuous emission monitoring system and flow monitoring system for each affected unit. The owner or operator shall comply with the applicable provisions specified in §§ 75.11(a) through (e) or § 75.16, except that the phrase ''CO_2 continuous emission monitoring system'' shall apply rather than ''SO_2 continuous emission monitoring system,'' the phrase ''CO_2 concentration'' shall apply rather than ''SO_2 concentration,'' the term ''maximum potential concentration of CO_2'' shall apply rather than ''maximum potential concentration of SO_2,'' and the phrase ''CO_2 mass emissions'' shall apply rather than ''SO_2 mass emissions.''

* * * * *

(c) *Determination of CO_2 mass emissions using an O_2 monitor according to appendix F to this part.* If the owner or operator chooses to use the appendix F method, then the owner or operator may determine hourly CO_2 concentration and mass emissions with a flow monitoring system; a continuous O_2 concentration monitor; fuel F and F_c factors; and, where O_2 concentration is measured on a dry basis, a continuous moisture monitoring system, as specified in § 75.11(b)(2), or a fuel-specific default moisture percentage (if applicable), as defined in § 75.11(b)(1), and by using the methods and procedures specified in appendix F to this part. For units using a common stack, multiple stack, or bypass stack, the owner or operator may use the provisions of § 75.16, except that the phrase ''CO_2 continuous emission monitoring system'' shall apply rather than ''SO_2 continuous emission monitoring system,'' the term ''maximum potential concentration of CO_2'' shall apply rather than ''maximum potential concentration of SO_2,'' and the phrase ''CO_2 mass emissions'' shall apply rather than ''SO_2 mass emissions.''

* * * * *

16. Section 75.16 is amended by:

a. Revising paragraphs (b)(2)(ii)(B), (b)(2)(ii)(D), (d)(2), and (e)(1);

b. Removing paragraphs (e)(2) and (e)(3);

c. Redesignating existing paragraphs (e)(4) and (e)(5) as paragraphs (e)(2) and (e)(3), respectively;

d. Adding a new sentence to the end of the newly designated paragraph (e)(3); and

e. Adding a new paragraph (e)(4), to read as follows:

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

* * * * *

(b) * * *

(2) * * *

(ii) * * *

(B) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system and flow monitoring system in the duct from each nonaffected unit; determine SO_2 mass emissions from the affected units as the difference between SO_2 mass emissions measured in the common stack and SO_2 mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly average value less than zero; combine emissions for the Phase I and Phase II affected units for recordkeeping and compliance purposes; and calculate and report SO_2 mass emissions from the Phase I and Phase II affected units, pursuant to an approach approved by the Administrator, such that these emissions are not underestimated; or

* * * * *

(D) Petition through the designated representative and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the units using the common stack and on reporting the SO_2 mass emissions. The Administrator may approve such demonstrated substitute methods for apportioning and reporting SO_2 mass emissions measured in a common stack whenever the demonstration ensures that there is a complete and accurate accounting of all emissions regulated under this part and, in particular, that the emissions from any affected unit are not underestimated.

* * * * *

(d) * * *

(2) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system and flow monitoring system in each stack. Determine SO_2 mass emissions from each affected unit as the sum of the SO_2 mass emissions recorded for each stack. Notwithstanding the prior sentence, if another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable common stack requirements of this section to determine and record SO_2 mass emissions from the units using that stack and shall calculate and report SO_2 mass emissions from the affected units and stacks, pursuant to an approach approved by the Administrator, such that these emissions are not underestimated.

(e) * * *

(1) The owner or operator of an affected unit using a common stack, bypass stack, or multiple stack with a diluent monitor and a flow monitor on each stack may choose to install monitors to determine the heat input for the affected unit, wherever flow and diluent monitor measurements are used to determine the heat input, using the procedures specified in paragraphs (a) through (d) of this section, except that the term ''heat input'' shall apply rather than ''SO_2 mass emissions'' or ''emissions'' and the phrase ''a diluent monitor and a flow monitor'' shall apply rather than ''SO_2 continuous emission monitoring system and flow monitoring system.'' The applicable equation in appendix F to this part shall be used to calculate the heat input from the hourly flow rate, diluentmonitor measurements, and (if the equation in appendix F requires a correction for the stack gas moisture content) hourly moisture measurements. Notwithstanding the options for combining heat input in paragraphs (a)(1)(ii), (a)(2)(ii), (b)(1)(ii), and (b)(2)(ii) of this section, the owner or operator of an affected unit with a diluent monitor and a flow monitor installed on a common stack to determine the combined heat input at the common stack shall also determine and report heat input to each individual unit.

* * * * *

(3) * * * If using either of these apportionment methods, the owner or operator shall apportion according to section 5.6 of appendix F to this part.

(4) Notwithstanding paragraph (e)(1) of this section, any affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_X mass emission reduction program must also meet the requirements for monitoring heat input in §§ 75.71, 75.72 and 75.75.

17. Section 75.17 is amended by revising paragraph (a)(2)(i)(C) to read as follows:

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

* * * * *

(a) * * *

(2) * * *

(i) * * *

(C) Each unit's compliance with the applicable NO_X emission limit will be determined by a method satisfactory to the Administrator for apportioning to each of the units the combined NO_X emission rate (in lb/mmBtu) measured in the common stack and for reporting the NO_X emission rate, as provided in a petition submitted by the designated representative. The Administrator may approve such demonstrated substitute methods for apportioning and reporting NO_X emission rate measured in a common stack whenever the demonstration ensures that there is a complete and accurate estimation of all emissions regulated under this part and, in particular, that the emissions from any unit with a NO_X emission limitation are not underestimated.

* * * * *

18. Section 75.19 is amended by:

a. Redesignating Tables 1, 2, 3, 4, 5 and 6 as LM–1, LM–2, LM–3, LM–4, LM–5 and LM–6, respectively;

b. Revising all references to Tables 1, 2, 3, 4, 5 and 6 in § 75.19 to LM–1, LM–2, LM–3, LM–4, LM–5, and LM–6, respectively;

c. Revising newly designated Table LM–5;

d. Correcting paragraph (c)(3)(ii)(D)(*2*) and the term ''$EFNO_X$'' that follows Eq. LM–10 in paragraph (c)(4)(ii)(A) to read as follows:

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

* * * * *

(c) * * *

(3) * * *

(ii) * * *

(D) * * *

(*2*) Using the appropriate default specific gravity value in Table LM–6 of this section.

* * * * *

(4) * * *

(ii) * * *

(A) * * *

Where:

* * * * *

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

* * * * *

TABLE LM–5.—DEFAULT GROSS CALORIFIC VALUES (GCVS) FOR VARIOUS FUELS

Fuel	GCV for use in equation LM–2 or LM–3
Pipeline Natural Gas	1050 Btu/scf.
Natural Gas	1100 Btu/scf.
Residual Oil	19,700 Btu/lb or 167,500 Btu/gallon.
Diesel Fuel	20,500 Btu/lb or 151,700 Btu/gallon.

* * * * *

Subpart C—Operation and Maintenance Requirements

19. Section 75.20 is amended by:

a. Revising the title of the section;

b. Revising the titles of paragraphs (c), (d) and (g);

c. Revising the introductory text of paragraphs (a), (c) and (g);

d. Revising paragraphs (a)(1), (a)(3), (a)(4) introductory text, (a)(4)(i), (a)(4)(ii), (a)(4)(iii), (a)(5)(i), (b), (c)(1), (c)(1)(i), (c)(1)(ii), (c)(1)(iii), (d)(1), (d)(2), (g)(1), (g)(1)(i), (g)(2), (g)(4), (g)(5) and (h)(2);

e. Removing existing paragraph (c)(3);

f. Redesignating existing paragraphs (c)(4), (c)(5), (c)(6), (c)(7), and (c)(8) as paragraphs (c)(3), (c)(4), (c)(8), (c)(9), and (c)(10), respectively;

g. Revising newly redesignated paragraphs (c)(3), (c)(4) introductory text, (c)(8) introductory text, (c)(8)(i), and (c)(10) introductory text; and

h. Adding new paragraphs (c)(5), (c)(6), (c)(7), (g)(6) and (g)(7), to read as follows:

§ 75.20 Initial certification and recertification procedures.

(a) *Initial certification approval process.* The owner or operator shall ensure that each continuous emission or opacity monitoring system required by this part, which includes the automated data acquisition and handling system, and, where applicable, the CO_2 continuous emission monitoring system, meets the initial certification requirements of this section and shall ensure that all applicable initial certification tests under paragraph (c) of this section are completed by the deadlines specified in § 75.4 and prior to use in the Acid Rain Program. In addition, whenever the owner or operator installs a continuous emission or opacity monitoring system in order to meet the requirements of §§ 75.11 through 75.18, where no continuous emission or opacity monitoring system was previously installed, initial certification is required.

(1) *Notification of initial certification test dates.* The owner or operator or designated representative shall submit a written notice of the dates of initial certification testing at the unit as specified in § 75.61(a)(1).

* * * * *

(3) *Provisional approval of certification (or recertification) applications.* Upon the successful completion of the required certification (or recertification) procedures of this section for each continuous emission or opacity monitoring system or component thereof, continuous emission or opacity monitoring system or component thereof shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program for a period not to exceed 120 days following receipt by the Administrator of the complete certification (or recertification) application under paragraph (a)(4) of this section. Notwithstanding this paragraph, no continuous emission or opacity monitor systems for a combustion source seeking to enter the Opt-in Program in accordance with part 74 of this chapter shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program. Data measured and recorded by a provisionally certified (or recertified) continuous emission or opacity monitoring system or component thereof, operated in accordance with the requirements of appendix B to this part, will be considered valid quality-assured data (retroactive to the date and time of provisional certification or recertification), provided that the Administrator does not invalidate the provisional certification (or recertification) by issuing a notice of disapproval within 120 days of receipt by the Administrator of the complete certification (or recertification) application. Note that when the data validation procedures of paragraph (b)(3) of this section are used for the initial certification (or recertification) of a continuous emissions monitoring system, the date and time of provisional certification (or recertification) of the CEMS may be earlier than the date and time of completion of the required certification (or recertification) tests.

(4) *Certification (or recertification) application formal approval process.* The Administrator will issue a notice of approval or disapproval of the certification (or recertification) application to the owner or operator within 120 days of receipt of the complete certification (or recertification) application. In the event the Administrator does not issue such a notice within 120 days of receipt, each continuous emission or opacity monitoring system which meets the performance requirements of this part and is included in the certification (or recertification) application will be deemed certified (or recertified) for use under the Acid Rain Program.

(i) *Approval notice.* If the certification (or recertification) application is complete and shows that each continuous emission or opacity monitoring system meets the performance requirements of this part, then the Administrator will issue a notice of approval of the certification (or recertification) application within 120 days of receipt.

(ii) *Incomplete application notice.* A certification (or recertification) application will be considered complete when all of the applicable information required to be submitted in § 75.63 has been received by the Administrator, the EPA Regional Office, and the appropriate State and/or local air pollution control agency. If the certification (or recertification) application is not complete, then the Administrator will issue a notice of incompleteness that provides a reasonable timeframe for the designated representative to submit the additional information required to complete the certification (or recertification) application. If the designated representative has not complied with the notice of incompleteness by a specified due date, then the Administrator may issue a notice of disapproval specified under paragraph (a)(4)(iii) of this section. The 120-day review period shall not begin prior to receipt of a complete application.

(iii) *Disapproval notice.* If the certification (or recertification) application shows that any continuous emission or opacity monitoring system or component thereof does not meet the performance requirements of this part, or if the certification (or recertification) application is incomplete and the requirement for disapproval under paragraph (a)(4)(ii) of this section has been met, the Administrator shall issue a written notice of disapproval of the certification (or recertification) application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification (or recertification) is invalidated by the Administrator, and the data measured and recorded by each uncertified continuous emission or opacity monitoring system or component thereof shall not be considered valid quality-assured data as follows: from the hour of the probationary calibration error test that began the initial certification (or recertification) test period (if the data validation procedures of paragraph (b)(3) of this section were used to retrospectively validate data); or from the date and time of completion of the invalid certification or recertification tests (if the data validation procedures of paragraph (b)(3) of this section were not used), until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests. The owner or operator shall follow the procedures for loss of initial certification in paragraph (a)(5) of this section for each continuous emission or opacity monitoring system or component thereof which is disapproved for initial certification. For each disapproved recertification, the owner or operator shall follow the procedures of paragraph (b)(5) of this section.

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(5) * * *

(i) Until such time, date, and hour as the continuous emission monitoring system or component thereof can be adjusted, repaired, or replaced and certification tests successfully completed, the owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid data specified in paragraph (a)(4)(iii) of this section or in § 75.21: the maximum potential concentration of SO_2, as defined in section 2.1.1.1 of appendix A to this part, to report SO_2 concentration; the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter, to report NO_X emissions in lb/mmBtu; the maximum potential concentration of

NO_X, as defined in section 2.1.2.1 of appendix A to this part, to report NO_X emissions in ppm (when a NO_X concentration monitoring system is used to determine NO_X mass emissions, as defined under § 75.71(a)(2)); the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, to report volumetric flow; the maximum potential concentration of CO_2, as defined in section 2.1.3.1 of appendix A to this part, to report CO_2 concentration data; and either the minimum potential moisture percentage, as defined in section 2.1.5 of appendix A to this part or, if Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate, the maximum potential moisture percentage, as defined in section 2.1.6 of appendix A to this part; and

* * * * *

(b) *Recertification approval process.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous emission monitoring system or continuous opacity monitoring system that may significantly affect the ability of the system to accurately measure or record the SO_2 or CO_2 concentration, stack gas volumetric flow rate, NO_X emission rate, percent moisture, or opacity, or to meet the requirements of § 75.21 or appendix B to this part, the owner or operator shall recertify the continuous emission monitoring system or continuous opacity monitoring system, according to the procedures in this paragraph. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that may significantly change the flow or concentration profile, the owner or operator shall recertify the monitoring system according to the procedures in this paragraph. Examples of changes which require recertification include: replacement of the analyzer; change in location or orientation of the sampling probe or site; and complete replacement of an existing continuous emission monitoring system or continuous opacity monitoring system. The owner or operator shall recertify a continuous opacity monitoring system whenever the monitor path length changes or as required by an applicable State or local regulation or permit. Any change to a flow monitor or gas monitoring system for which a RATA is not necessary shall not be considered a recertification event. In addition, changing the polynomial coefficients or K factor(s) of a flow monitor shall require a 3-load RATA, but is not considered to be a recertification event; however, records of the polynomial coefficients or K factor (s) currently in use shall be maintained on-site in a format suitable for inspection. Changing the coefficient or K factor(s) of a moisture monitoring system shall require a RATA, but is not considered to be a recertification event; however, records of the coefficient or K factor (s) currently in use by the moisture monitoring system shall be maintained on-site in a format suitable for inspection. In such cases, any other tests that are necessary to ensure continued proper operation of the monitoring system (e.g., 3-load flow RATAs following changes to flow monitor polynomial coefficients, linearity checks, calibration error tests, DAHS verifications, etc.) shall be performed as diagnostic tests, rather than as recertification tests. The data validation procedures in paragraph (b)(3) of this section shall be applied to RATAs associated with changes to flow or moisture monitor coefficients, and to linearity checks, 7-day calibration error tests, and cycle time tests, when these are required as diagnostic tests. When the data validation procedures of paragraph (b)(3) of this section are applied in this manner, replace the word ''recertification'' with the word ''diagnostic.''

(1) *Tests required.* For all recertification testing, the owner or operator shall complete all initial certification tests in paragraph (c) of this section that are applicable to the monitoring system, except as otherwise approved by the Administrator. For diagnostic testing after changing the flow rate monitor polynomial coefficients, the owner or operator shall complete a 3-level RATA. For diagnostic testing after changing the K factor or mathematical algorithm of a moisture monitoring system, the owner or operator shall complete a RATA.

(2) *Notification of recertification test dates.* The owner, operator, or designated representative shall submit notice of testing dates for recertification under this paragraph as specified in § 75.61(a)(1)(ii), unless all of the tests in paragraph (c) of this section are not required for recertification, in which case the owner or operator shall provide notice in accordance with the notice provisions for initial certification testing in § 75.61(a)(1)(i).

(3) *Recertification test period requirements and data validation.* The data validation provisions in paragraphs (b)(3)(i) through (b)(3)(ix) of this section shall apply to all CEMS recertifications and diagnostic testing. The provisions in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section may also be applied to initial certifications (see sections 6.2(a), 6.3.1(a), 6.3.2(a), 6.4(a) and 6.5(f) of appendix A to this part) and may be used to supplement the linearity check and RATA data validation procedures in sections 2.2.3(b) and 2.3.2(b) of appendix B to this part.

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

(ii) Once the modification or change to the CEMS has been completed and all of the associated repairs, component replacements, adjustments, linearization, and reprogramming of the CEMS have been completed, a probationary calibration error test is required to establish the beginning point of the recertification test period. In this instance, the first successful calibration error test of the monitoring system following completion of all necessary repairs, component replacements, adjustments, linearization and reprogramming shall be the probationary calibration error test. The probationary calibration error test must be passed before any of the required recertification tests are commenced.

(iii) Beginning with the hour of commencement of a recertification test period, emission data recorded by the CEMS are considered to be conditionally valid, contingent upon the results of the subsequent recertification tests.

(iv) Each required recertification test shall be completed no later than the following number of unit operating hours (or unit operating days) after the probationary calibration error test that initiates the test period:

(A) For a linearity check and/or cycle time test, 168 consecutive unit operating hours, as defined in § 72.2 of this chapter or, for CEMS installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter;

(B) For a RATA (whether normal-load or multiple-load), 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; and

(C) For a 7-day calibration error test, 21 consecutive unit operating days, as defined in § 72.2 of this chapter.

(v) All recertification tests shall be performed hands-off. No adjustments to the calibration of the CEMS, other than the routine calibration adjustments following daily calibration error tests as described in section 2.1.3 of appendix B to this part, are permitted during the recertification test period. Routine daily calibration error tests shall be performed throughout the recertification test period, in accordance with section 2.1.1 of appendix B to this part. The additional calibration error test requirements in section 2.1.3 of appendix B to this part shall also apply during the recertification test period.

(vi) If all of the required recertification tests and required daily calibration error tests are successfully completed in succession with no failures, and if each recertification test is completed within the time period specified in paragraph (b)(3)(iv)(A), (B), or (C) of this section, then all of the conditionally valid emission data recorded by the CEMS shall be considered quality assured, from the hour of commencement of the recertification test period until the hour of completion of the required test(s).

(vii) If a required recertification test is failed or aborted due to a problem with the CEMS, or if a daily calibration error test is failed during a recertification test period, data validation shall be done as follows:

(A) If any required recertification test is failed, it shall be repeated. If any recertification test other than a 7-day calibration error test is failed or aborted due to a problem with the CEMS, the original recertification test period is ended, and a new recertification test period must be commenced with a probationary calibration error test. The tests that are required in the new recertification test period will include any tests that were required for the initial recertification event which were not successfully completed and any recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct the problems that caused the failure of the recertification test. For a 2- or 3-load flow RATA, if the relative accuracy test is passed at one or more load levels, but is failed at a subsequent load level, provided that the problem that caused the RATA failure is corrected without re-linearizing the instrument, the length of the new recertification test period shall be equal to the number of unit operating hours remaining in the original recertification test period, as of the hour of failure of the RATA. However, if re-linearization of the flow monitor is required after a flow RATA is failed at a particular load level, then a subsequent 3-load RATA is required, and the new recertification test period shall be 720 consecutive unit (or stack) operating hours. The new recertification test sequence shall not be commenced until all necessary maintenance activities, adjustments, linearizations, and reprogramming of the CEMS have been completed;

(B) If a linearity check, RATA, or cycle time test is failed or aborted due to a problem with the CEMS, all conditionally valid emission data recorded by the CEMS are invalidated, from the hour of commencement of the recertification test period to the hour in which the test is failed or aborted, except for the case in which a multiple-load flow RATA is passed at one or more load levels, failed at a subsequent load level, and the problem that caused the RATA failure is corrected without re-linearizing the instrument. In that case, data invalidation shall be prospective, from the hour of failure of the RATA until the commencement of the new recertification test period. Data from the CEMS remain invalid until the hour in which a new recertification test period is commenced, following corrective action, and a probationary calibration error test is passed, at which time the conditionally valid status of emission data from the CEMS begins again;

(C) If a 7-day calibration error test is failed within the recertification test period, previously-recorded conditionally valid emission data from the CEMS are not invalidated. The conditionally valid data status is unaffected, unless the calibration error on the day of the failed 7-day calibration error test exceeds twice the performance specification in section 3 of appendix A to this part, as described in paragraph (b)(3)(vii)(D) of this section; and

(D) If a daily calibration error test is failed during a recertification test period (i.e., the results of the test exceed twice the performance specification in section 3 of appendix A to this part), the CEMS is out-of-control as of the hour in which the calibration error test is failed. Emission data from the CEMS shall be invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test following corrective action, at which time the conditionally valid status of data from the monitoring system resumes. Failure to perform a required daily calibration error test during a recertification test period shall also cause data from the CEMS to be invalidated prospectively, from the hour in which the calibration error test was due until the hour of completion of a subsequent successful calibration error test. Whenever a calibration error test is failed or missed during a recertification test period, no further recertification tests shall be performed until the required subsequent calibration error test has been passed, re-establishing the conditionally valid status of data from the monitoring system. If a calibration error test failure occurs while a linearity check or RATA is still in progress, the linearity check or RATA must be re-started.

(E) Trial gas injections and trial RATA runs are permissible during the recertification test period, prior to commencing a linearity check or RATA, for the purpose of optimizing the performance of the CEMS. The results of such gas injections and trial runs shall not affect the status of previously-recorded conditionally valid data or result in termination of the recertification test period, provided that the following specifications and conditions are met:

(*1*) For gas injections, the stable, ending monitor response is within ±5 percent or within 5 ppm of the tag value of the reference gas;

(*2*) For RATA trial runs, the average reference method reading and the average CEMS reading for the run differ by no more than ±10% of the average reference method value or ±15 ppm, or ±1.5% H_2O, or ±0.02 lb/mmBtu from the average reference method value, as applicable;

(*3*) No adjustments to the calibration of the CEMS are made following the trial injection(s) or run(s), other than the adjustments permitted under section 2.1.3 of appendix B to this part; and

(*4*) The CEMS is not repaired, re-linearized or reprogrammed (e.g., changing flow monitor polynomial coefficients, linearity constants, or K-factors) after the trial injection(s) or run(s).

(F) If the results of any trial gas injection(s) or RATA run(s) are outside the limits in paragraphs (b)(3)(vii)(E)(*1*) or (*2*) of this section or if the CEMS is repaired, re-linearized or reprogrammed after the trial injection(s) or run(s), the trial injection(s) or run(s) shall be counted as a failed linearity check or RATA attempt. If this occurs, follow the procedures pertaining to failed and aborted recertification tests in paragraphs (b)(3)(vii)(A) and (b)(3)(vii)(B) of this section.

(viii) If any required recertification test is not completed within its allotted time period, data validation shall be done as follows. For a late linearity test, RATA, or cycle time test that is passed on the first attempt, data from the monitoring system shall be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. For a late 7-day calibration error test, whether or not it is passed on the first attempt, data from the monitoring system shall also be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. For a late linearity test, RATA, or cycle time test that is failed on the first attempt or aborted on the first attempt due to a problem with the monitor, all conditionally valid data from the monitoring system shall be considered invalid back to the hour of the first probationary calibration error test which initiated the recertification test period. Data from the monitoring system shall remain invalid until the hour of successful completion of the late recertification test and any additional recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct problems that caused failure of the late recertification test.

(ix) If any required recertification test of a monitoring system has not been completed by the end of a calendar quarter and if data contained in the quarterly report are conditionally valid pending the results of test(s) to be completed in a subsequent quarter, the owner or operator shall indicate this by means of a suitable conditionally valid data flag in the electronic quarterly report for that quarter. The owner or operator shall resubmit the report for that quarter if the required recertification test is subsequently failed. In the resubmitted report, the owner or operator shall use the appropriate missing data routine in § 75.31 or § 75.33 to replace with substitute data each hour of conditionally valid data that was invalidated by the failed recertification test. Alternatively, if any required recertification test is not completed by the end of a particular calendar quarter but is completed no later than 30 days after the end of that quarter (i.e., prior to the deadline for submitting the quarterly report under § 75.64), the test data and results may be submitted with the earlier quarterly report even though the test date(s) are from the next calendar quarter. In such instances, if the recertification test(s) are passed in accordance with the provisions of paragraph (b)(3) of this section, conditionally valid data may be reported as quality-assured, in lieu of reporting a conditional data flag. If the recertification test(s) is failed and if conditionally valid data are replaced, as appropriate, with substitute data, then neither the reporting of a conditional data flag nor resubmission is required. In addition, if the owner or operator uses a conditionally valid data flag in any of the four quarterly reports for a given year, the owner or operator shall indicate the final status of the conditionally valid data (i.e., resolved or unresolved) in the annual compliance certification report required under § 72.90 of this chapter for that year. The Administrator may invalidate any conditionally valid data that remains unresolved at the end of a particular calendar year and may require the owner or operator to resubmit one or more of the quarterly reports for that calendar year, replacing the unresolved conditionally valid data with substitute data values determined in accordance with § 75.31 or § 75.33, as appropriate.

(4) *Recertification application.* The designated representative shall apply for recertification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The owner or operator shall submit the recertification application in accordance with § 75.60, and each complete recertification application shall include the information specified in § 75.63.

(5) *Approval or disapproval of request for recertification.* The procedures for provisional certification in paragraph (a)(3) of this section shall apply to recertification applications. The Administrator will issue a notice of approval, disapproval, or incompleteness according to the procedures in paragraph (a)(4) of this section. 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 probationary calibration error test that began the recertification test period. Data from the monitoring system remain invalid until a subsequent probationary calibration error test is passed, beginning a new recertification test period. The owner or operator shall repeat all recertification tests or other requirements, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval. The designated representative shall submit a notification of the recertification retest dates, as specified in § 75.61(a)(1)(ii), and shall submit a new recertification application according to the procedures in paragraph (b)(4) of this section.

(c) *Initial certification and recertification procedures.* Prior to the deadline in § 75.4, the owner or operator shall conduct initial certification tests and in accordance with § 75.63, the designated representative shall submit an application to demonstrate that the continuous emission or opacity monitoring system and components thereof meet the specifications in appendix A to this part. The owner or operator shall compare reference method values with output from the automated data acquisition and handling system that is part of the continuous emission monitoring system being tested. Except as specified in paragraphs (b)(1), (d), and (e) of this section, the owner or operator shall perform the following tests for initial certification or recertification of continuous emission or opacity monitoring systems or components according to the requirements of appendix A to this part:

(1) For each SO_2 pollutant concentration monitor, each NO_X concentration monitoring system used to determine NO_X mass emissions, as

defined under § 75.71(a)(2), and for each NO_X-diluent continuous emission monitoring system:

(i) A 7-day calibration error test, where, for the NO_X-diluent continuous emission monitoring system, the test is performed separately on the NO_X pollutant concentration monitor and the diluent gas monitor;

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

(iii) A relative accuracy test audit. For the NO_X-diluent continuous emission monitoring system, the RATA shall be done on a system basis, in units of lb/mmBtu. For the NO_X concentration monitoring system, the RATA shall be done on a ppm basis.

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(3) The initial certification test data from an O_2 or a CO_2 diluent gas monitor certified for use in a NO_X continuous emission monitoring system may be submitted to meet the requirements of paragraph (c)(4) of this section. Also, for a diluent monitor that is used both as a CO_2 monitoring system and to determine heat input, only one set of diluent monitor certification data need be submitted (under the component and system identification numbers of the CO_2 monitoring system).

(4) For each CO_2 pollutant concentration monitor, each O_2 monitor which is part of a CO_2 continuous emission monitoring system, each diluent monitor used to monitor heat input and each SO_2-diluent continuous emission monitoring system:

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(5) For each continuous moisture monitoring system consisting of wet- and dry-basis O_2 analyzers:

(i) A 7-day calibration error test of each O_2 analyzer;

(ii) A cycle time test of each O_2 analyzer;

(iii) A linearity test of each O_2 analyzer; and

(iv) A RATA, directly comparing the percent moisture measured by the monitoring system to a reference method.

(6) For each continuous moisture sensor: A RATA, directly comparing the percent moisture measured by the monitor sensor to a reference method.

(7) For a continuous moisture monitoring system consisting of a temperature sensor and a data acquisition and handling system (DAHS) software component programmed with a moisture lookup table:

(i) A demonstration that the correct moisture value for each hour is being taken from the moisture lookup tables and applied to the emission calculations. At a minimum, the demonstration shall be made at three different temperatures covering the normal range of stack temperatures from low to high.

(ii) [Reserved]

(8) The owner or operator shall ensure that initial certification or recertification of a continuous opacity monitor for use under the Acid Rain Program is conducted according to one of the following procedures:

(i) Performance of the tests for initial certification or recertification, according to the requirements of Performance Specification 1 in appendix B to part 60 of this chapter; or

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(10) The owner or operator shall provide adequate facilities for initial certification or recertification testing that include:

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(d) *Initial certification and recertification and quality assurance procedures for optional backup continuous emission monitoring systems.* (1) *Redundant backups.* The owner or operator of an optional redundant backup CEMS shall comply with all the requirements for initial certification and recertification according to the procedures specified in paragraphs (a), (b), and (c) of this section. The owner or operator shall operate the redundant backup CEMS during all periods of unit operation, except for periods of calibration, quality assurance, maintenance, or repair. The owner or operator shall perform upon the redundant backup CEMS all quality assurance and quality control procedures specified in appendix B to this part, except that the daily assessments in section 2.1 of appendix B to this part are optional for days on which the redundant backup CEMS is not used to report emission data under this part. For any day on which a redundant backup CEMS is used to report emission data, the system must meet all of the applicable daily assessment criteria in appendix B to this part.

(2) *Non-redundant backups.* The owner or operator of an optional non-redundant backup CEMS or like-kind replacement analyzer shall comply with all of the following requirements for initial certification, quality assurance, recertification, and data reporting:

(i) Except as provided in paragraph (d)(2)(v) of this section, for a regular non-redundant backup CEMS (i.e., a non-redundant backup CEMS that has its own separate probe, sample interface, and analyzer), or a non-redundant backup flow monitor, all of the tests in paragraph (c) of this section are required for initial certification of the system, except for the 7-day calibration error test.

(ii) For a like-kind replacement non-redundant backup analyzer (i.e., a non-redundant backup analyzer that uses the same probe and sample interface as a primary monitoring system), no initial certification of the analyzer is required. A non-redundant backup analyzer, connected to the same probe and interface as a primary CEMS in order to satisfy the dual span requirements of section 2.1.1.4 or 2.1.2.4 of appendix A to this part, shall be treated in the same manner as a like-kind replacement analyzer.

(iii) Each non-redundant backup CEMS or like-kind replacement analyzer shall comply with the daily and quarterly quality assurance and quality control requirements in appendix B to this part for each day and quarter that the non-redundant backup CEMS or like-kind replacement analyzer is used to report data, and shall meet the additional linearity and calibration error test requirements specified in this paragraph. The owner or operator shall ensure that each non-redundant backup CEMS or like-kind replacement analyzer passes a linearity check (for pollutant concentration and diluent gas monitors) or a calibration error test (for flow monitors) prior to each use for recording and reporting emissions. For a primary NO_X-diluent or SO_2-diluent CEMS consisting of the primary pollutant analyzer and a like-kind replacement diluent analyzer (or vice-versa), provided that the primary pollutant or diluent analyzer (as applicable) is operating and is not out-of-control with respect to any of its quality assurance requirements, only the like-kind replacement analyzer must pass a linearity check before the system is used for data reporting. When a non-redundant backup CEMS or like-kind replacement analyzer is brought into service, prior to conducting the linearity test, a probationary calibration error test (as described in paragraph (b)(3)(ii) of this section), which will begin a period of conditionally valid data, may be performed in order to allow the validation of data retrospectively, as follows. Conditionally valid data from the CEMS or like-kind replacement analyzer are validated back to the hour of completion of the probationary calibration error test if the following conditions are met: if no adjustments are made to the CEMS or like-kind replacement analyzer other than the allowable calibration adjustments specified in section 2.1.3 of appendix B to this part between the probationary calibration error test and the successful completion of the linearity test; and if the linearity test is passed within 168 unit (or stack) operating hours of the probationary calibration error test. However, if the linearity test is either failed, aborted due to a problem with the CEMS or like-kind replacement analyzer, or is not completed as required, 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.

(iv) When data are reported from a non-redundant backup CEMS or like-kind replacement analyzer, the appropriate bias adjustment factor shall be determined as follows:

(A) For a regular non-redundant backup CEMS, as described in paragraph (d)(2)(i) of this section, apply the bias adjustment factor from the most recent RATA of the non-redundant backup system (even if that RATA was done more than 12 months previously); or

(B) When a like-kind replacement non-redundant backup analyzer is used as a component of a primary CEMS (as described in paragraph (d)(2)(ii) of this section), apply the primary monitoring system bias adjustment factor.

(v) For each parameter monitored (i.e., SO_2, CO_2, NO_X or flow rate) at each unit or stack, a regular non-redundant backup CEMS may not be used to report data at that affected unit or common stack for more than 720 hours in any one calendar year, unless the CEMS passes a RATA at that unit or stack. For each parameter monitored (SO_2, CO_2 or NO_X) at each unit or stack, the use of a like-kind replacement non-redundant backup analyzer (or analyzers) is restricted to 720 cumulative hours per calendar year, unless the owner or operator redesignates the like-kind replacement analyzer(s) as component(s) of regular non-redundant backup CEMS and each redesignated CEMS passes a RATA at that unit or stack.

(vi) For each regular non-redundant backup CEMS, no more than eight successive calendar quarters shall elapse following the quarter in which the last RATA of the CEMS was done at a particular unit or stack, without performing a subsequent RATA. Otherwise, the CEMS may not be used to report data from that unit or stack until the hour of completion of a passing RATA at that location.

(vii) Each regular non-redundant backup CEMS shall be represented in the monitoring plan required under § 75.53 as a separate monitoring system, with unique system and component identification numbers. When like-kind replacement non-redundant backup analyzers are used, the owner or operator shall represent each like-kind replacement analyzer used during a particular calendar quarter in the monitoring plan required under § 75.53 as a component of a primary monitoring system. The owner or operator shall also assign a unique component identification number to each like-kind replacement analyzer and specify the manufacturer, model and serial number of the like-kind replacement analyzer. This information may be added, deleted or updated as necessary, from quarter to quarter. The owner or operator shall also report data from the like-kind replacement analyzer using the system identification number of the primary monitoring system and the assigned component identification number of the like-kind replacement analyzer. For the purposes of the electronic quarterly report required under § 75.64, the owner or operator may manually enter the appropriate component identification number(s) of any like-kind replacement analyzer(s) used for data reporting during the quarter.

(viii) When reporting data from a certified regular non-redundant backup CEMS, use a method of determination (MODC) code of ‘‘02.’’ When reporting data from a like-kind replacement non-redundant backup analyzer, use a MODC of ‘‘17’’ (see Table 4a under § 75.57). For the purposes of the electronic quarterly report required under § 75.64, the owner or operator may manually enter the required MODC of ‘‘17’’ for a like-kind replacement analyzer.

* * * * *

(g) *Initial certification and recertification procedures for excepted monitoring systems under appendices D and E.* The owner or operator of a gas-fired unit, oil-fired unit, or diesel-fired unit using the optional protocol under appendix D or E to this part shall ensure that an excepted monitoring system under appendix D or E to this part meets the applicable general operating requirements of § 75.10, the applicable requirements of appendices D and E to this part, and the initial certification or recertification requirements of this paragraph.

(1) *Initial certification and recertification testing.* The owner or operator shall use the following procedures for initial certification and recertification of an excepted monitoring system under appendix D or E to this part.

(i) When the optional SO_2 mass emissions estimation procedure in appendix D to this part or the optional NO_X emissions estimation protocol in appendix E to this part is used, the owner or operator shall provide data from a flowmeter accuracy test (or shall provide a statement of calibration if the flowmeter meets the accuracy standard by design) for each fuel flowmeter, according to section 2.1.5.1 of appendix D to this part.

* * * * *

(2) *Initial certification and recertification testing notification.* The designated representative shall provide initial certification testing notification and routine periodic retesting notification for an excepted monitoring system under appendix E to this part as specified in § 75.61. The designated representative shall also submit recertification testing notification, as specified in § 75.61, for quality assurance related NO_X emission rate re-testing under section 2.3 of appendix E to this part for an excepted monitoring system under appendix E to this part. Initial certification testing notification or periodic retesting notification is not required for testing of a fuel flowmeter or for testing of an excepted monitoring system under appendix D to this part.

* * * * *

(4) *Initial certification or recertification application.* The designated representative shall submit an initial certification or recertification application in accordance with §§ 75.60 and 75.63.

(5) *Provisional approval of initial certification and recertification applications.* Upon the successful completion of the required initial certification or recertification procedures for each excepted monitoring system under appendix D or E to this part, each excepted monitoring system under appendix D or E to this part shall be deemed provisionally certified for use under the Acid Rain Program during the period for the Administrator's review. The provisions for the initial certification or recertification application formal approval process in paragraph (a)(4) of this section shall apply, except that the term ‘‘excepted monitoring system'' shall apply rather than ‘‘continuous emission or opacity monitoring system'' and except that the procedures for loss

of certification in paragraph (g)(7) of this section shall apply rather than the procedures for loss of certification in either paragraph (a)(5) or (b)(5) of this section. Data measured and recorded by a provisionally certified excepted monitoring system under appendix D or E to this part will be considered quality assured data from the date and time of completion of the last initial certification or recertification test, provided that the Administrator does not revoke the provisional certification or recertification by issuing a notice of disapproval in accordance with the provisions in paragraph (a)(4) or (b)(5) of this section.

(6) *Recertification requirements.* Recertification of an excepted monitoring system under appendix D or E to this part is required for any modification to the system or change in operation that could significantly affect the ability of the system to accurately account for emissions and for which the Administrator determines that an accuracy test of the fuel flowmeter or a retest under appendix E to this part to re-establish the NO_X correlation curve is required. Examples of such changes or modifications include fuel flowmeter replacement, changes in unit configuration, or exceedance of operating parameters.

(7) *Procedures for loss of certification or recertification for excepted monitoring systems under appendices D and E to this part.* In the event that a certification or recertification application is disapproved for an excepted monitoring system, data from the monitoring system are invalidated, and the applicable missing data procedures in section 2.4 of appendix D or section 2.5 of appendix E to this part shall be used from the date and hour of receipt of such notice back to the hour of the provisional certification. Data from the excepted monitoring system remain invalid until all required tests are repeated and the excepted monitoring system is again provisionally certified. The owner or operator shall repeat all certification or recertification tests or other requirements, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval. The designated representative shall submit a notification of the certification or recertification retest dates if required under paragraph (g)(2) of this section and shall submit a new certification or recertification application according to the procedures in paragraph (g)(4) of this section.

(h) * * *

(2) *Certification application.* The designated representative shall submit a certification application in accordance with § 75.63(a)(1)(iii).

* * * * *

20. Section 75.21 is amended by:

a. Revising paragraphs (a)(2), (a)(4), (a)(5), (a)(6), and (e);

b. Redesignating existing paragraphs (a)(7) and (a)(8) as paragraphs (a)(9) and (a)(10), respectively; and revising newly designated paragraphs (a)(9) and (a)(10); and

c. Adding new paragraphs (a)(7) and (a)(8) to read as follows:

§ 75.21 Quality assurance and quality control requirements.

(a) * * *

(2) The owner or operator shall ensure that each non-redundant backup CEMS meets the quality assurance requirements of § 75.20(d) for each day and quarter that the system is used to report data.

* * * * *

(4) The owner or operator of a unit with an SO_2 continuous emission monitoring system is not required to perform the daily or quarterly assessments of the SO_2 monitoring system under appendix B to this part on any day or in any calendar quarter in which only gaseous fuel is combusted in the unit if, during those days and calendar quarters, SO_2 emissions are determined in accordance with § 75.11(e)(1) or (e)(2). However, such assessments are permissible, and if any daily calibration error test or linearity test of the SO_2 monitoring system is failed while the unit is combusting only gaseous fuel, the SO_2 monitoring system shall be considered out-of-control. The length of the out-of-control period shall be determined in accordance with the applicable procedures in section 2.1.4 or 2.2.3 of appendix B to this part.

(5) For a unit with an SO_2 continuous monitoring system, in which gaseous fuel that is very low sulfur fuel (as defined in § 72.2 of this chapter) is sometimes burned as a primary or backup fuel and in which higher-sulfur fuel(s) such as oil or coal are, at other times, burned as primary or backup fuel(s), the owner shall perform the relative accuracy test audits of the SO_2 monitoring system (as required by section 6.5 of appendix A to this part and section 2.3.1 of appendix B to this part) only when the higher-sulfur fuel is combusted in the unit and shall not perform SO_2 relative accuracy test audits when the very low sulfur gaseous fuel is the only fuel being combusted.

(6) If the designated representative certifies that a unit with an SO_2 monitoring system burns only very low sulfur fuel (as defined in § 72.2 of this chapter), the SO_2 monitoring system is exempted from the relative accuracy test audit requirements in appendices A and B to this part.

(7) If the designated representative certifies that a particular unit with an SO_2 monitoring system combusts primarily fuel(s) that are very low sulfur fuel(s) (as defined in § 72.2 of this chapter), and combusts higher sulfur fuel (s) only as emergency backup fuel(s) or for short-term testing, the SO_2 monitoring system shall be exempted from the RATA requirements of appendices A and B to this part in any calendar year that the unit combusts the higher-sulfur fuel(s) for no more than 480 hours. If, in a particular calendar year, the higher-sulfur fuel usage exceeds 480 hours, the owner or operator shall perform a RATA of the SO_2 monitor (while combusting the higher-sulfur fuel) either by the end of the calendar quarter in which the exceedance occurs or by the end of a 720 unit (or stack) operating hour grace period (under section 2.3.3 of appendix B to this part) following the quarter in which the exceedance occurs.

(8) On and after April 1, 2000, the quality assurance provisions of §§ 75.11(e)(3)(i) through 75.11(e)(3)(iv) shall apply to all units with SO_2 monitoring systems during hours in which only very low sulfur fuel (as defined in § 72.2 of this chapter) is combusted in the unit.

(9) Provided that a unit with an SO_2 monitoring system is not exempted under paragraphs (a)(6) or (a)(7) of this section from the SO_2 RATA requirements of this part, any calendar quarter during which a unit combusts only very low sulfur fuel (as defined in § 72.2 of this chapter) shall be excluded in determining the quarter in which the next relative accuracy test audit must be performed for the SO_2 monitoring system. However, no more than eight successive calendar quarters shall elapse after a relative accuracy test audit of an SO_2 monitoring system, without a subsequent relative accuracy test audit having been performed. The owner or operator shall ensure that a relative accuracy test audit is performed, in accordance with paragraph (a)(5) of this section, either by the end of the eighth successive elapsed calendar quarter since the last RATA or by the end of a 720 unit (or stack) operating hour grace period, as provided in section 2.3.3 of appendix B to this part.

(10) The owner or operator who, in accordance with § 75.11(e)(1), uses a certified flow monitor and a certified diluent monitor and Equation F–23 in appendix F to this part to calculate SO_2

emissions during hours in which a unit combusts only natural gas or pipeline natural gas (as defined in § 72.2 of this chapter) shall meet all quality control and quality assurance requirements in appendix B to this part for the flow monitor and the diluent monitor.

* * * * *

(e) *Consequences of audits.* The owner or operator shall invalidate data from a continuous emission monitoring system or continuous opacity monitoring system upon failure of an audit under appendix B to this part or any other audit, beginning with the unit operating hour of completion of a failed audit as determined by the Administrator. The owner or operator shall not use invalidated data for reporting either emissions or heat input, nor for calculating monitor data availability.

(1) *Audit decertification.* Whenever both an audit of a continuous emission or opacity monitoring system (or component thereof, including the data acquisition and handling system), of any excepted monitoring system under appendix D or E to this part, or of any alternative monitoring system under subpart E of this part, and a review of the initial certification application or of a recertification application, reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement of this part, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such system or component. For the purposes of this paragraph, an audit shall be either a field audit of the facility or an audit of any information submitted to EPA or the State agency regarding the facility. By issuing the notice of disapproval, the certification status is revoked prospectively by the Administrator. The data measured and recorded by each system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests. The owner or operator shall follow the procedures in § 75.20(a)(5) for initial certification or § 75.20(b)(5) for recertification to replace, prospectively, all of the invalid, non-quality-assured data for each disapproved system.

(2) *Out-of-control period.* Whenever a continuous emission monitoring system or continuous opacity monitoring system fails a quality assurance audit or any another audit, the system is out-of-control. The owner or operator shall follow the procedures for out-of-control periods in § 75.24.

21. Section 75.22 is amended by adding a sentence to the end of the introductory text of paragraph (a) and by revising paragraphs (a)(2), (a)(4), (b)(4) and the introductory text of paragraph (c)(1) to read as follows:

§ 75.22 Reference test methods.

(a) * * * Unless otherwise specified in this part, use only codified versions of Methods 3A, 4, 6C and 7E revised as of July 1, 1995 or July 1, 1996 or July 1, 1997.

* * * * *

(2) Method 2 or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, are the reference methods for determination of volumetric flow.

* * * * *

(4) Method 4 (either the standard procedure described in section 2 of the method or the moisture approximation procedure described in section 3 of the method) shall be used to correct pollutant concentrations from a dry basis to a wet basis (or from a wet basis to a dry basis) and shall be used when relative accuracy test audits of continuous moisture monitoring systems are conducted. For the purpose of determining the stack gas molecular weight, however, the alternative techniques for approximating the stack gas moisture content described in section 1.2 of Method 4 may be used in lieu of the procedures in sections 2 and 3 of the method.

* * * * *

(b) * * *

(4) Method 2, or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, for determining volumetric flow. The sample point(s) for reference methods shall be located according to the provisions of section 6.5.5 of appendix A to this part.

(c)(1) Instrumental EPA Reference Methods 3A, 6C, 7E, and 20 shall be conducted using calibration gases as defined in section 5 of appendix A to this part. Otherwise, performance tests shall be conducted and data reduced in accordance with the test methods and procedures of this part unless the Administrator:

* * * * *

22. Section 75.24 is amended by revising the section title and by revising paragraph (d) to read as follows:

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

* * * * *

(d) When the bias test indicates that an SO_2 monitor, a flow monitor, a NO_X-diluent continuous emission monitoring system or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2), is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test or calculate and use the bias adjustment factor as specified in section 2.3.4 of appendix B to this part.

* * * * *

Subpart D—Missing Data Substitution Procedures

23. Section 75.30 is amended by revising paragraphs (a)(3) and (a)(4), adding new paragraphs (a)(5) and (a)(6), revising the first sentence of paragraph (b) and revising paragraph (d) to read as follows:

§ 75.30 General provisions.

(a) * * *

(3) A valid, quality-assured hour of NO_X emission rate data (in lb/mmBtu) has not been measured or recorded for an affected unit, either by a certified NO_X-diluent continuous emission monitoring system or by an approved alternative monitoring system under subpart E of this part; or

(4) A valid, quality-assured hour of CO_2 concentration data (in percent CO_2, or percent O_2 converted to percent CO_2 using the procedures in appendix F to this part) has not been measured and recorded for an affected unit, either by a certified CO_2 continuous emission monitoring system or by an approved alternative monitoring method under subpart E of this part; or

(5) A valid, quality-assured hour of NO_X concentration data (in ppm) has not been measured or recorded for an affected unit, either by a certified NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2), or by an approved alternative monitoring system under subpart E of this part; or

(6) A valid, quality-assured hour of CO_2 or O_2 concentration data (in percent CO_2, or percent O_2) used for the determination of heat input has not been measured and recorded for an

affected unit, either by a certified CO_2 or O_2 diluent monitor, or by an approved alternative monitoring method under subpart E of this part.

(b) However, the owner or operator shall have no need to provide substitute data according to the missing data procedures in this subpart if the owner or operator uses SO_2, CO_2, NO_X, or O_2 concentration, flow rate, or NO_X emission rate data recorded from either a certified redundant or regular non-redundant backup CEMS, a like-kind replacement non-redundant backup analyzer, or a backup reference method monitoring system when the certified primary monitor is not operating or is out-of-control. * * *

* * * * *

(d) The owner or operator shall comply with the applicable provisions of this paragraph during hours in which a unit with an SO_2 continuous emission monitoring system combusts only gaseous fuel.

(1) Whenever a unit with an SO_2 CEMS combusts only natural gas or pipeline natural gas (as defined in § 72.2 of this chapter) and the owner or operator is using the procedures in section 7 of appendix F to this part to determine SO_2 mass emissions pursuant to § 75.11(e)(1), the owner or operator shall, for purposes of reporting heat input data under § 75.54(b)(5) or § 75.57(b)(5), as applicable, and for the calculation of SO_2 mass emissions using Equation F–23 in section 7 of appendix F to this part, substitute for missing data from a flow monitoring system, CO_2 diluent monitor or O_2 diluent monitor using the missing data substitution procedures in § 75.36.

(2) Whenever a unit with an SO_2 CEMS combusts gaseous fuel and the owner or operator uses the gas sampling and analysis and fuel flow procedures in appendix D to this part to determine SO_2 mass emissions pursuant to § 75.11(e)(2), the owner or operator shall substitute for missing total sulfur content, gross calorific value, and fuel flowmeter data using the missing data procedures in appendix D to this part and shall also, for purposes of reporting heat input data under § 75.54(b)(5) or § 75.57(b)(5), as applicable, substitute for missing data from a flow monitoring system, CO_2 diluent monitor, or O_2 diluent monitor using the missing data substitution procedures in § 75.36.

(3) The owner or operator of a unit with an SO_2 monitoring system shall not include hours when the unit combusts only gaseous fuel in the SO_2 data availability calculations in § 75.32 or in the calculations of substitute SO_2 data using the procedures of either § 75.31 or § 75.33, for hours when SO_2 emissions are determined in accordance with § 75.11(e)(1) or (e)(2). For the purpose of the missing data and availability procedures for SO_2 pollutant concentration monitors in §§ 75.31 and 75.33 only, all hours during which the unit combusts only gaseous fuel shall be excluded from the definition of ''monitor operating hour,'' ''quality assured monitor operating hour,'' ''unit operating hour,'' and ''unit operating day,'' when SO_2 emissions are determined in accordance with § 75.11(e)(1) or (e)(2).

(4) During all hours in which a unit with an SO_2 continuous emission monitoring system combusts only gaseous fuel and the owner or operator uses the SO_2 monitoring system to determine SO_2 mass emissions pursuant to § 75.11(e)(3), the owner or operator shall determine the percent monitor data availability for SO_2 in accordance with § 75.32 and shall use the standard SO_2 missing data procedures of § 75.33.

24. Section 75.31 is revised to read as follows:

§ 75.31 Initial missing data procedures.

(a) During the first 720 quality-assured monitor operating hours following initial certification (i.e., the date and time at which quality assured data begins to be recorded by the CEMS) of an SO_2 pollutant concentration monitor, or a CO_2 pollutant concentration monitor (or an O_2 monitor used to determine CO_2 concentration in accordance with appendix F to this part), or an O_2 or CO_2 diluent monitor used to calculate heat input or a moisture monitoring system, and during the first 2,160 quality-assured monitor operating hours following initial certification of a flow monitor, or a NO_X-diluent monitoring system, or a NO_X concentration monitoring system used to determine NO_X mass emissions, the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section. The owner or operator of a unit shall use these procedures for no longer than three years (26,280 clock hours) following initial certification.

(b) *SO_2*, CO_2, or O_2 concentration data and moisture data. For each hour of missing SO_2 or CO_2 pollutant concentration data (including CO_2 data converted from O_2 data using the procedures in appendix F of this part), or missing O_2 or CO_2 diluent concentration data used to calculate heat input, or missing moisture data, the owner or operator shall calculate the substitute data as follows:

(1) Whenever prior quality-assured data exist, the owner or operator shall substitute, by means of the data acquisition and handling system, for each hour of missing data, the average of the hourly SO_2, CO_2 or O_2 concentrations or moisture percentages recorded by a certified monitor for the unit operating hour immediately before and the unit operating hour immediately after the missing data period.

(2) Whenever no prior quality assured SO_2, CO_2 or O_2 concentration data or moisture data exist, the owner or operator shall substitute, as applicable, for each hour of missing data, the maximum potential SO_2 concentration or the maximum potential CO_2 concentration or the minimum potential O_2 concentration or (unless Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate) the minimum potential moisture percentage, as specified, respectively, in sections 2.1.1.1, 2.1.3.1, 2.1.3.2 and 2.1.5 of appendix A to this part. If Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate, substitute the maximum potential moisture percentage, as specified in section 2.1.6 of appendix A to this part.

(c) *Volumetric flow and NO_X emission rate or* NO_X concentration 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 corresponding to the operating load at the time the missing data period occurred, the owner or operator shall substitute, by means of the automated data acquisition and handling system, for each hour of missing data, the average hourly flow rate or NO_X emission rate or NO_X concentration recorded by a certified monitoring system. The average flow rate (or NO_X emission rate or NO_X concentration) shall be the arithmetic average of all data in the corresponding load range as determined using the procedure in appendix C to this part.

(2) Whenever no prior quality-assured flow or NO_X emission rate or NO_X concentration data exist for the corresponding load range, the owner or operator shall substitute, for each hour of missing data, the average hourly flow rate or the average hourly NO_X emission rate or NO_X concentration at the next higher level load range for which quality-assured data are available.

(3) Whenever no prior quality assured flow rate or NO_X emission rate or NO_X concentration data exist for the corresponding load range, or any higher load range, 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 shall substitute 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.

25. Section 75.32 is amended by revising paragraph (a) introductory text and revising the last sentence in paragraph (a)(3) to read as follows:

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

(a) Following initial certification (i.e., the date and time at which quality assured data begins to be recorded by the CEMS), upon completion of: the first 720 quality-assured monitor operating hours of an SO_2 pollutant concentration monitor, or a CO_2 pollutant concentration monitor (or O_2 monitor used to determine CO_2 concentration), or an O_2 or CO_2 diluent monitor used to calculate heat input or a moisture monitoring system; or the first 2,160 quality-assured monitor operating hours of a flow monitor or a NO_X-diluent monitoring system or a NO_X concentration monitoring system, the owner or operator shall calculate and record, by means of the automated data acquisition and handling system, the percent monitor data availability for the SO_2 pollutant concentration monitor, the CO_2 pollutant concentration monitor, the O_2 or CO_2 diluent monitor used to calculate heat input, the moisture monitoring system, the flow monitor, the NO_X-diluent monitoring system and the NO_X concentration monitoring system as follows:

* * * * *

(3) * * * The owner or operator of a unit with an SO_2 monitoring system shall, when SO_2 emissions are determined in accordance with § 75.11(e)(1) or (e)(2), exclude hours in which a unit combusts only gaseous fuel from calculations of percent monitor data availability for SO_2 pollutant concentration monitors, as provided in § 75.30(d).

* * * * *

26. Section 75.33 is amended by revising the title of the section, by revising paragraphs (a), (b)(3) and (c), and adding a new paragraph (b)(4) to read as follows:

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

(a) Following initial certification (i.e., the date and time at which quality assured data begins to be recorded by the CEMS) and upon completion of the first 720 quality-assured monitor operating hours of the SO_2 pollutant concentration monitor or the first 2,160 quality assured monitor operating hours of the flow monitor, NO_X-diluent monitoring system or NO_X concentration monitoring system used to determine NO_X mass emissions, 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 sectioin (NO_X, flow). The owner or operator of a unit shall substitute for missing data using only quality-assured monitor operating hours of data from the three years (26,280 clock hours) prior to the date and time of the missing data period.

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	$N \leq 24$	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	$N \leq 8$	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_2O^X)	None.

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

* = Quality-assured, monitor operating hours, during unit operation.

[1] Where unit with add-on 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.—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	$N \leq 24$	Average	2160 hours*	Yes.
	$N > 24$	The greater of:		
		Average	HB/HA	No.
		90th percentile	2160 hours*	Yes.
90 or more, but below 95	$N \leq 8$	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 concentration; or maximum potential flow rate.	None	No.

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

*=Quality-assured, monitor operating hours, in the corresponding load range (''load bin'') for each hour of the missing data period.

[1] Where unit with add-on 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.

(b) * * *

(3) Whenever the monitor data availability is at least 80.0 percent but less than 90.0 percent, the owner or operator shall substitute for each missing data period the maximum hourly SO_2 concentration recorded by an SO_2 pollutant concentration monitor during the previous 720 quality-assured monitor operating hours.

(4) Whenever the monitor data availability is less than 80.0 percent, the owner or operator shall substitute for each missing data period the maximum potential SO_2 concentration, as defined in section 2.1.1.1 of appendix A to this part.

(c) *Volumetric flow rate, NO_X emission rate and NO_X concentration 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 the monitor or continuous emission monitoring system 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 flow rates or NO_X emission rates or NO_X concentrations recorded by a monitoring system during the previous 2,160 quality assured monitor operating hours at the corresponding unit load range, as determined using the procedure in appendix C to this part.

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

(A) The 90th percentile hourly flow rate or 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 at the corresponding unit load range, as determined using the procedure in appendix C to this part; or

(B) The average of the recorded hourly flow rates, NO_X emission rates or NO_X concentrations recorded by a monitoring system for the hour before and the hour after the missing data period.

(2) Whenever the monitor or continuous emission monitoring system 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 8 hours, substitute, as applicable, the arithmetic average hourly flow rate or NO_X emission rate or NO_X concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range, as determined using the procedure in appendix C to this part.

(ii) For a missing data period greater than 8 hours, substitute, as applicable, for each missing hour, the greater of:

(A) The 95th percentile hourly flow rate or the 95th percentile NO_X emission rate or the 95th percentile NO_X concentration recorded by a monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range, as determined using the procedure in appendix C to this part; or

(B) The average of the hourly flow rates, NO_X emission rates or NO_X concentrations recorded by a monitoring system for the hour before and the hour after the missing data period.

(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 flow rate or 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 at the corresponding unit load range, as determined using the procedure in section 2 of appendix C to this part.

(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 potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, or the maximum NO_X emission rate, as defined in section 2.1.2.1 of appendix A to this part, or the maximum potential NO_X concentration, as defined in section 2.1.2.1 of appendix A to this part.

(5) Whenever no prior quality-assured flow rate data, NO_X concentration data or NO_X emission rate data exist for the corresponding load range, the owner or operator shall substitute, as applicable, for each hour of missing data, the

maximum hourly flow rate or the maximum hourly NO_X concentration or maximum hourly NO_X emission rate at the next higher level load range for which quality-assured data are available.

(6) Whenever no prior quality-assured flow rate data, NO_X concentration data or NO_X emission rate data exist for either the corresponding load range or a higher load range, the owner or operator shall substitute, as applicable, either the maximum potential NO_X emission rate or the maximum potential NO_X concentration, as defined in section 2.1.2.1 of appendix A to this part or the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part.

27–28. Section 75.34 is amended by revising paragraph (a)(3) to read as follows:

§ 75.34 Units with add-on emission controls.

(a) * * *

(3) The designated representative may petition the Administrator under § 75.66 for approval of site-specific parametric monitoring procedure(s) for calculating substitute data for missing SO_2 pollutant concentration, NO_X pollutant concentration, and NO_X emission rate data in accordance with the requirements of paragraphs (b) and (c) of this section and appendix C to this part. The owner or operator shall record the data required in appendix C to this part, pursuant to § 75.55(b) or § 75.58(b), as applicable.

* * * * *

29. Section 75.35 is amended by revising paragraphs (a) and (b) and by adding paragraph (d) to read as follows:

§ 75.35 Missing data procedures for CO_2 data.

(a) On and after April 1, 2000, 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. The procedures of paragraphs (b) and (d) of this section shall also be used on and after April 1, 2000 to provide substitute CO_2 data for heat input determination. Prior to April 1, 2000, the owner or operator shall substitute for missing CO_2 data using either the procedures of paragraphs (b) and (c), or paragraphs (b) and (d) of this section.

(b) During the first 720 quality assured monitor operating hours following initial certification (i.e., the date and time at which quality assured data begins to be recorded by the CEMS), of the CO_2 continuous emission monitoring system, or (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).

* * * * *

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

30. Section 75.36 is amended by revising the section heading and paragraphs (a), (b) and (d) to read as follows:

§ 75.36 Missing data procedures for heat input determinations.

(a) When hourly heat input is determined using a flow monitoring system and a diluent gas (O_2 or CO_2) monitor, substitute data must be provided to calculate the heat input whenever quality assured data are unavailable from the flow monitor, the diluent gas monitor, or both. When flow rate data are unavailable, substitute flow rate data for the heat input calculation shall be provided according to § 75.31 or § 75.33, as applicable. On and after April 1, 2000, when diluent gas data are unavailable, the owner or operator shall provide substitute O_2 or CO_2 data for the heat input calculations in accordance with paragraphs (b) and (d) of this section. Prior to April 1, 2000, the owner or operator shall substitute for missing CO_2 or O_2 concentration data in accordance with either paragraphs (c) and (d) or paragraphs (b) and (d) of this section.

(b) During the first 720 quality assured monitor operating hours following initial certification (i.e., the date and time at which quality assured data begins to be recorded by the CEMS), or (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) * * *

(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 or O_2 concentration to calculate heat input, as follows. Substitute CO_2 data for heat input determinations shall be provided according to § 75.35(d). Substitute O_2 data for the heat input determinations shall be provided in accordance with the procedures in § 75.33(b), except that the term ''O_2 concentration'' shall apply rather than the term ''SO_2 concentration'' and the term ''O_2 diluent monitor'' shall apply rather than the term ''SO_2 pollutant concentration monitor.'' In addition, the term ''substitute the lesser of'' shall apply rather than ''substitute the greater of;'' the terms ''minimum hourly O_2 concentration'' and ''minimum potential O_2 concentration, as determined under section 2.1.3.2 of appendix A to this part'' shall apply rather than, respectively, the terms ''maximum hourly SO_2 concentration'' and ''maximum potential SO_2 concentration, as determined under section 2.1.1.1 of appendix A to this part;'' and the terms ''10th percentile'' and ''5th percentile'' shall apply rather than, respectively, the terms ''90th percentile'' and ''95th percentile'' (see Table 1 of § 75.33).

31. Section 75.37 is added to subpart D to read as follows:

§ 75.37 Missing data procedures for moisture.

(a) On and after April 1, 2000, the owner or operator of a unit with a continuous moisture monitoring system shall substitute for missing moisture data using the procedures of this section. Prior to April 1, 2000, the owner or operator may substitute for missing moisture data using the procedures of this section.

(b) Where no prior quality assured moisture data exist, substitute the minimum potential moisture percentage, from section 2.1.5 of appendix A to this part, except when Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate. If Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate, substitute the maximum potential moisture percentage, as specified in section 2.1.6 of appendix A to this part.

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

(d) Upon completion of the first 720 quality-assured monitor operating hours following initial certification of the moisture monitoring system, the owner or operator shall provide substitute data for moisture as follows:

(1) Unless Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate, follow 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 the term ''SO_2 pollutant concentration monitor;'' the term ''substitute the lesser of'' shall apply rather than ''substitute the greater of;'' the terms ''minimum hourly moisture percentage'' and ''minimum potential moisture percentage, as determined under section 2.1.5 of appendix A to this part'' shall apply rather than, respectively, the terms ''maximum hourly SO_2 concentration'' and ''maximum potential SO_2 concentration, as determined under section 2.1.1.1 of appendix A to this part;'' and the terms ''10th percentile'' and ''5th percentile'' shall apply rather than, respectively, the terms ''90th percentile'' and ''95th percentile'' (see Table 1 of § 75.33).

(2) When Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate:

(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'' and the term ''moisture monitoring system'' shall apply rather than ''SO_2 pollutant concentration monitor;'' or

(ii) If any 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, the owner or operator shall petition the Administrator under § 75.66(l) for permission to use an alternative moisture missing data procedure.

Subpart E—Alternative Monitoring Systems

32. Section 75.48 is amended by revising paragraphs (a)(3)(ii) and (a)(3)(iii), and correcting paragraphs (a)(3)(iv), (a)(3)(viii), (a)(3)(ix), and (a)(3)(xi) to read as follows:

§ 75.48 Petition for an alternative monitoring system.

(a) * * *

(3) * * *

(ii) Hourly test data for the alternative monitoring system at each required operating level and fuel type. The fuel type, operating level and gross unit load shall be recorded.

(iii) Hourly test data for the continuous emissions monitoring system at each required operating level and fuel type. The fuel type, operating level and gross unit load shall be recorded.

(iv) Arithmetic mean of the alternative monitoring system measurement values, as specified in Equation 25 in § 75.41(c) of this part, of the continuous emission monitoring system values, as specified in Equation 26 in § 75.41(c) of this part, and of their differences.

* * * * *

(viii) Variance of the measured values for the alternative monitoring system and of the measured values for the continuous emission monitoring system, as specified in Equation 23 in § 75.41(c) of this part.

(ix) F-statistic, as specified in Equation 24 in § 75.41(c) of this part.

* * * * *

(xi) Coefficient of correlation, r, as specified in Equation 27 in § 75.41(c) of this part.

* * * * *

Subpart F—Recordkeeping Requirements

§ 75.50 [Removed and Reserved]

33. Section 75.50 is removed and reserved.

§ 75.51 [Removed and Reserved]

34. Section 75.51 is removed and reserved.

§ 75.52 [Removed and Reserved]

35. Section 75.52 is removed and reserved.

§ 75.53 Monitoring plan.

36. Section 75.53 is amended by revising paragraphs (a) and (b), correcting paragraph (c)(1), and adding paragraphs (e) and (f) to read as follows:

(a) *General provisions.* (1) The provisions of paragraphs (c) and (d) of this section shall remain in effect prior to April 1, 2000. The owner or operator shall meet the requirements of either paragraphs (a) through (d) or paragraphs (a), (b), (e) and (f) of this section prior to April 1, 2000. On and after April 1, 2000, the owner or operator shall meet the requirements of paragraphs (a), (b), (e) and (f) of this section only. In addition, the provisions in paragraphs (e) and (f) of this section that support a regulatory option provided in another section of this part must be followed if the regulatory option is used prior to April 1, 2000.

(2) The owner or operator of an affected unit shall prepare and maintain a monitoring plan. Except as provided in paragraphs (d) or (f) of this section (as applicable), a monitoring plan shall contain sufficient information on the continuous emission or opacity monitoring systems, excepted methodology under § 75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these systems to demonstrate that all unit SO_2 emissions, NO_X emissions, CO_2 emissions, and opacity are monitored and reported.

(b) Whenever the owner or operator makes a replacement, modification, or change in the certified CEMS, continuous opacity monitoring system, excepted methodology under § 75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

(c) * * *

(1) Precertification information, including, as applicable, the identification of the test strategy, protocol for the relative accuracy test audit, other relevant test information, span calculations, and apportionment strategies under §§ 75.10 through 75.18 of this part.

* * * * *

(e) *Contents of the monitoring plan.* Each monitoring plan shall contain the information in paragraph (e)(1) of this section in electronic format and the information in paragraph (e)(2) of this section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

(1) *Electronic.* (i) ORISPL numbers developed by the Department of Energy and used in the National Allowance Data Base, for all affected units involved in the monitoring plan, with the following information for each unit:

(A) Short name;

(B) Classification of the unit as one of the following: Phase I (including substitution or compensating units), Phase II, new, or nonaffected;

(C) Type of boiler (or boilers for a group of units using a common stack);

(D) Type of fuel(s) fired by boiler, fuel type start and end dates, primary/secondary fuel indicator, and, if more than one fuel, the fuel classification of the boiler;

(E) Type(s) of emission controls for SO_2, NO_X, and particulates installed or to be installed, including specifications of whether such controls are pre-combustion, post-combustion, or integral to the combustion process; control equipment code, installation date, and optimization date; control equipment retirement date (if applicable); and an indicator for whether the controls are an original installation;

(F) Maximum hourly heat input capacity;

(G) Date of first commercial operation;

(H) Unit retirement date (if applicable);

(I) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in 1000 lb/hr, rounded to the nearest 100 lb/hr);

(J) Identification of all units using a common stack;

(K) Activation date for the stack/pipe;

(L) Retirement date of the stack/pipe (if applicable); and

(M) Indicator of whether the stack is a bypass stack.

(ii) For each unit and parameter required to be monitored, identification of monitoring methodology information, consisting of monitoring methodology, type of fuel associated with the methodology, primary/secondary methodology indicator, missing data approach for the methodology, methodology start date, and methodology end date (if applicable).

(iii) The following information:

(A) Program(s) for which the EDR is submitted;

(B) Unit classification;

(C) Reporting frequency;

(D) Program participation date;

(E) State regulation code (if applicable); and

(F) State or local regulatory agency code.

(iv) Identification and description of each monitoring component (including each monitor and its identifiable components, such as analyzer and/or probe) in the CEMS (e.g., SO_2 pollutant concentration monitor, flow monitor, moisture monitor; NO_X pollutant concentration monitor and diluent gas monitor), the continuous opacity monitoring system, or the excepted monitoring system (e.g., fuel flowmeter, data acquisition and handling system), including:

(A) Manufacturer, model number and serial number;

(B) Component/system identification code assigned by the utility to each identifiable monitoring component (such as the analyzer and/or probe). Each code shall use a three-digit format, unique to each monitoring component and unique to each monitoring system;

(C) Designation of the component type and method of sample acquisition or operation, (e.g., in situ pollutant concentration monitor or thermal flow monitor);

(D) Designation of the system as a primary, redundant backup, non-redundant backup, data backup, or reference method backup system, as provided in § 75.10(e);

(E) First and last dates the system reported data;

(F) Status of the monitoring component; and

(G) Parameter monitored.

(v) Identification and description of all major hardware and software components of the automated data acquisition and handling system, including:

(A) Hardware components that perform emission calculations or store data for quarterly reporting purposes (provide the manufacturer and model number); and

(B) Software components (provide the identification of the provider and model/version number).

(vi) Explicit formulas for each measured emission parameter, using component/system identification codes for the primary system used to measure the parameter that links CEMS or excepted monitoring system observations with reported concentrations, mass emissions, or emission rates, according to the conversions listed in appendix D or E to this part. Formulas for backup monitoring systems are required only if different formulas for the same parameter are used for the primary and backup monitoring systems (e.g., if the primary system measures pollutant concentration on a different moisture basis from the backup system). The formulas must contain all constants and factors required to derive mass emissions or emission rates from component/system code observations and an indication of whether the formula is being added, corrected, deleted, or is unchanged. Each emissions formula is identified with a unique three digit code. The owner or operator of a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) is not required to report such formulas.

(vii) Inside cross-sectional area (ft^2) at flue exit (for all units) and at flow monitoring location (for units with flow monitors, only).

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

(ix) Part 75 monitoring location identification, facility identification code as assigned by the Administrator for use under the Acid Rain Program or this part, and the following information, as reported to the Energy Information Administration (EIA): facility identification number, flue identification number, boiler identification number, reporting year, and 767 reporting indicator.

(x) For each parameter monitored: scale, maximum potential concentration (and method of calculation), maximum expected concentration (if applicable) (and method of calculation), maximum potential flow rate (and method of calculation), maximum potential NO_X emission rate, span value, full-scale range, daily calibration units of measure, span effective date/hour, span inactivation date/hour, indication of whether dual spans are required, default high range value, flow rate span, and flow rate span value and full scale value (in scfh) for each unit or stack using SO_2, NO_X, CO_2, O_2, or flow component monitors.

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

(A) Identification of the parameter;

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

(C) Purpose of the value;

(D) Indicator of use during controlled/uncontrolled hours;

(E) Type of fuel;

(F) Source of the value;

(G) Value effective date and hour;

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

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

(xii) For each unit or common stack (except for peaking units) on which hardware CEMS are installed:

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

(B) The load level(s) designated as normal in section 6.5.2.1 of appendix A to this part, expressed in megawatts or thousands of lb/hr of steam;

(C) The two load levels (i.e., low, mid, or high) identified in section 6.5.2.1 of appendix A to this part as the most frequently used;

(D) The date of the load analysis used to determine the normal load level(s) and the two most frequently-used load levels; and

(E) Activation and deactivation dates, when the normal load level(s) or two most frequently-used load levels change and are updated.

(xiii) For each unit for which the optional fuel flow-to-load test in section 2.1.7 of appendix D to this part is used:

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

(B) The load level designated as normal, pursuant to section 6.5.2.1 of appendix A to this part, expressed in megawatts or thousands of lb/hr of steam; and

(C) The date of the load analysis used to determine the normal load level.

(2) *Hardcopy.* (i) Information, including (as applicable): identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, maximum potential NO_X emission rate, and span; and apportionment strategies under §§ 75.10 through 75.18.

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

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

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

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

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

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

(i) *Electronic.*

(A) Parameter monitored;

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

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

(D) Submission status of the data;

(E) Monitoring system identification code; and

(F) For gaseous fuels fired by the unit, the method used to verify that the fuel meets the definition in § 72.2 of pipeline natural gas or natural gas, if applicable, and the demonstration methods used for other gaseous fuels, if applicable, to determine the appropriate frequency for sampling for GCV or sulfur content of the fuel.

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

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

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

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

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

(i) *Electronic.* Unit operating and capacity factor information demonstrating that the unit qualifies as a peaking unit or gas-fired unit, as defined in § 72.2 of this chapter, and NO_X correlation test information, including:

(A) Test date;

(B) Test number;

(C) Operating level;

(D) Segment ID of the NO_X correlation curve;

(E) NO_X monitoring system identification;

(F) Low and high heat input values and corresponding NO_X rates;

(G) Type of fuel; and

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

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

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

(3) For each gas-fired unit and diesel-fired unit or unit with a wet flue gas pollution control system for which the

designated representative claims an opacity monitoring exemption under § 75.14, the designated representative shall include in the hardcopy monitoring plan the information specified under § 75.14(b), (c), or (d), demonstrating that the unit qualifies for the exemption.

(4) For each monitoring system recertification, maintenance, or other event, the designated representative shall include the following additional information in electronic format in the monitoring plan:

(i) Component/system identification code;

(ii) Event code or code for required test;

(iii) Event begin date and hour;

(iv) Conditionally valid data period begin date and hour (if applicable);

(v) Date and hour that last test is successfully completed; and

(vi) Indicator of whether conditionally valid data were reported at the end of the quarter.

(5) For each unit using the low mass emission excepted methodology under § 75.19 the designated representative shall include the following additional information in the monitoring plan:

(i) *Electronic.* For each low mass emissions unit, report the results of the analysis performed to qualify as a low mass emissions unit under § 75.19(c). This report will include either the previous three years actual or projected emissions and the emissions calculated using the methodology which will be used by the unit to estimate future emissions.

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

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

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

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

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

(6) For each gas-fired unit the designated representative shall include in the monitoring plan, in electronic format, the following: current calendar year, fuel usage data as specified in the definition of gas-fired in § 72.2 of this part, and an indication of whether the data are actual or projected data.

37. Section 75.54 is amended by revising paragraph (a) introductory text and paragraph (a)(1), and adding a new paragraph (g) to read as follows:

§ 75.54 General recordkeeping provisions.

(a) *Recordkeeping requirements for affected sources.* On and after January 1, 1996, and before April 1, 2000, the owner or operator shall meet the requirements of either this section or § 75.57. On and after April 1, 2000, the owner or operator shall meet the requirements of § 75.57. The owner or operator of any affected source subject to the requirements of this part shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Unless otherwise provided, throughout this subpart the phrase ''for each affected unit'' also applies to each group of affected or nonaffected units utilizing a common stack and common monitoring systems, pursuant to §§ 75.16 through 75.18, or utilizing a common pipe header and common fuel flowmeter, pursuant to section 2.1.2 of appendix D to this part. The file shall contain the following information:

(1) The data and information required in paragraphs (b) through (g) of this section, beginning with the earlier of the date of provisional certification, or the deadline in § 75.4(a), (b) or (c);

* * * * *

(g) *Missing data records.* The owner or operator shall record the causes of any missing data periods and the actions taken by the owner or operator to cure such causes.

38. Section 75.55 is amended by adding introductory text prior to paragraph (a), by correcting paragraphs (b)(1)(i), (b)(1)(xi), (b)(2)(vii), by revising paragraph (e), and by removing paragraph (f) to read as follows:

§ 75.55 General recordkeeping provisions for specific situations.

Before April 1, 2000, the owner or operator shall meet the requirements of either this section or § 75.58. On and after April 1, 2000, the owner or operator shall meet the requirements of § 75.58.

* * * * *

(b) * * *

(1) * * *

(i) The information required in § 75.54(c) for SO_2 concentration and volumetric flow if either one of these monitors is still operating:

* * * * *

(xi) Method of determination of SO_2 concentration and volumetric flow, using Codes 1–15 in Table 4 of § 75.54; and

* * * * *

(2) * * *

(vii) Method of determination of NO_X emission rate using Codes 1–15 in Table 4 of § 75.54; and

* * * * *

(e) *Specific SO_2 emission record provisions during the combustion of gaseous fuel.* (1) If SO_2 emissions are determined in accordance with the provisions in § 75.11(e)(2) during hours in which only gaseous fuel is combusted in a unit with an SO_2 CEMS, the owner or operator shall record the information in paragraph (c)(3) of this section in lieu of the information in §§ 75.54(c)(1) and (c)(3) or §§ 75.57(c)(1) and (c)(4), for those hours.

(2) The provisions of this paragraph apply to a unit which, in accordance with the provisions of § 75.11(e)(3), uses an SO_2 CEMS to determine SO_2 emissions during hours in which only gaseous fuel is combusted in the unit. If the unit sometimes burns only gaseous fuel that is very low sulfur fuel (as defined in § 72.2 of this chapter) as a primary and/or backup fuel and at other times combusts higher-sulfur fuels, such as coal or oil, as primary and/or backup fuel(s), then the owner or operator shall keep records on-site, suitable for inspection, of the type(s) of fuel(s) burned during each period of missing SO_2 data and the number of hours that each type of fuel was combusted in the unit during each missing data period. This recordkeeping requirement does not apply to an affected unit that burns very low sulfur fuel exclusively, nor does it apply to a unit that burns such gaseous fuel(s) only during unit startup.

39. Section 75.56 is amended by adding introductory text prior to paragraph (a) adding new paragraphs (a)(5)(vii) through (a)(5)(ix) and removing paragraph (d) to read as follows:

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

Before April 1, 2000, the owner or operator shall meet the requirements of either this section or § 75.59. On and after April 1, 2000, the owner or operator shall meet the requirements of § 75.59.

(a) * * *

(5) * * *

(vii) For flow monitors, the equation used to linearize the flow monitor and the numerical values of the polynomial coefficients or K factor(s) of that equation.

(viii) The raw data and calculated results for any stratification tests performed in accordance with sections 6.5.6.1 through 6.5.6.3 in appendix A to this part.

(ix) For moisture monitoring systems, the coefficient or ''K'' factor or other mathematical algorithm used to adjust the monitoring system with respect to the reference method.

* * * * *

40. Section 75.57 is added to subpart F to read as follows:

§ 75.57 General recordkeeping provisions.

Before April 1, 2000, the owner or operator shall meet the requirements of either this section or § 75.54. However, the provisions of this section which support a regulatory option provided in another section of this part must be followed if that regulatory option is used prior to April 1, 2000. On or after April 1, 2000, the owner or operator shall meet the requirements of this section.

(a) *Recordkeeping requirements for affected sources.* The owner or operator of any affected source subject to the requirements of this part shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Unless otherwise provided, throughout this subpart the phrase ''for each affected unit'' also applies to each group of affected or nonaffected units utilizing a common stack and common monitoring systems, pursuant to §§ 75.16 through 75.18, or utilizing a common pipe header and common fuel flowmeter, pursuant to section 2.1.2 of appendix D to this part. The file shall contain the following information:

(1) The data and information required in paragraphs (b) through (h) of this section, beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);

(2) The supporting data and information used to calculate values required in paragraphs (b) through (g) of this section, excluding the subhourly data points used to compute hourly averages under § 75.10(d), beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);

(3) The data and information required in § 75.55 or § 75.58 for specific situations, as applicable, beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);

(4) The certification test data and information required in § 75.56 or § 75.59 for tests required under § 75.20, beginning with the date of the first certification test performed, the quality assurance and quality control data and information required in § 75.56 or § 75.59 for tests, and the quality assurance/quality control plan required under § 75.21 and appendix B to this part, beginning with the date of provisional certification;

(5) The current monitoring plan as specified in § 75.53, beginning with the initial submission required by § 75.62; and

(6) The quality control plan as described in section 1 of appendix B to this part, beginning with the date of provisional certification.

(b) *Operating parameter record provisions.* The owner or operator shall record for each hour the following information on unit operating time, heat input rate, and load, separately for each affected unit and also for each group of units utilizing a common stack and a common monitoring system or utilizing a common pipe header and common fuel flowmeter:

(1) Date and hour;

(2) Unit operating time (rounded up to the nearest 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));

(3) Hourly gross unit load (rounded to nearest MWge) (or steam load in 1000 lb/hr at stated temperature and pressure, rounded to the nearest 1000 lb/hr, if elected in the monitoring plan);

(4) Operating load range corresponding to hourly gross load of 1 to 10, except for units using a common stack or common pipe header, which may use up to 20 load ranges for stack or fuel flow, as specified in the monitoring plan;

(5) Hourly heat input rate (mmBtu/hr, rounded to the nearest tenth);

(6) Identification code for formula used for heat input, as provided in § 75.53; and

(7) For CEMS units only, F-factor for heat input calculation and indication of whether the diluent cap was used for heat input calculations for the hour.

(c) *SO_2 emission record provisions.* The owner or operator shall record for each hour the information required by this paragraph for each affected unit or group of units using a common stack and common monitoring systems, except as provided under § 75.11(e) or for a gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part or for a low mass emissions unit for which the owner or operator is using the optional low mass emissions methodology in § 75.19(c) for estimating SO_2 mass emissions:

(1) For SO_2 concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in § 75.53;

(ii) Date and hour;

(iii) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth);

(iv) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in § 75.24(d);

(v) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32; and

(vi) Method of determination for hourly average SO_2 concentration using Codes 1–55 in Table 4a of this section.

(2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in § 75.53;

(ii) Date and hour;

(iii) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand);

(iv) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias adjustment factor required, as provided in § 75.24(d);

(v) Percent monitor data availability (recorded to the nearest tenth of a percent) for the flow monitor, calculated pursuant to § 75.32; and

(vi) Method of determination for hourly average flow rate using Codes 1–55 in Table 4a of this section.

(3) For flue gas moisture content during unit operation (where SO_2 concentration is measured on a dry basis), as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in § 75.53;

(ii) Date and hour;

(iii) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the wet- and dry-basis oxygen hourly averages (in percent O_2, rounded to the nearest tenth);

(iv) Percent monitor data availability (recorded to the nearest tenth of a percent) for the moisture monitoring system, calculated pursuant to § 75.32; and

(v) Method of determination for hourly average moisture percentage, using Codes 1–55 in Table 4a of this section.

(4) For SO_2 mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination:

(i) Date and hour;

(ii) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth);

(iii) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in § 75.24(d); and

(iv) Identification code for emissions formula used to derive hourly SO_2 mass emission rate from SO_2 concentration and flow and (if applicable) moisture data in paragraphs (c)(1), (c)(2), and (c)(3) of this section, as provided in § 75.53.

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: NSO_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	Hourly average SO_2 concentration, CO_2 concentration, O_2 concentration, NO_X concentration, moisture percentage, flow rate, or NO_X emission rate using initial missing data procedures.
8	90th percentile hourly SO_2 concentration, CO_2 concentration, NO_X concentration, flow rate, moisture percentage, or NO_X emission rate or 10th percentile hourly O_2 concentration or moisture percentage (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 (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.
12	Maximum potential concentration of SO_2, maximum potential concentration of CO_2, maximum potential concentration of NO_X maximum potential flow rate, maximum potential NO_X emission rate, maximum potential moisture percentage, minimum potential O_2 concentration or minimum potential moisture percentage, as determined using section 2.1 of appendix A to this part (moisture missing data algorithm depends on which equations are used for emissions and heat input).
13	Fuel analysis data from appendix G to this part for CO_2 mass emissions. (This code is optional through 12/31/99, and shall not be used after 1/1/00.)
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	Fuel analysis data from appendix G to this part for CO_2 mass emissions. (This code is optional through 12/31/99, and shall not be used after 1/1/00.)
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 monitoring 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).
25	Maximum potential NO_X emission rate (MER). (Use only when a NO_X concentration full-scale exceedance occurs and the diluent monitor is unavailable.)
54	Other quality assured methodologies approved through petition. These hours are included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.
55	Other substitute data approved through petition. These hours are not included in missing data lookback and are treated as unavailable hours for percent monitor availability calculations.

(d) *NO_X emission record provisions.* The owner or operator shall record the applicable information required by this paragraph for each affected unit for each hour or partial hour during which the unit operates, except for a gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in appendix E to this part or a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) for estimating NO_X emission rate. For each NO_X emission rate (in lb/mmBtu) measured by a NO_X-diluent monitoring system, or, if applicable, for each NO_X concentration (in ppm) measured by a

NO_X concentration monitoring system used to calculate NO_X mass emissions under § 75.71(a)(2), record the following data as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(1) Component-system identification code, as provided in § 75.53 (including identification code for the moisture monitoring system, if applicable);

(2) Date and hour;

(3) Hourly average NO_X concentration (ppm, rounded to the nearest tenth) and hourly average NO_X concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in § 75.24(d);

(4) Hourly average diluent gas concentration (for NO_X-diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth);

(5) If applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);

(6) Hourly average NO_X emission rate (for NO_X-diluent monitoring systems only, in units of lb/mmBtu, rounded either to the nearest hundredth or thousandth prior to April 1, 2000 and rounded to the nearest thousandth on and after April 1, 2000);

(7) Hourly average NO_X emission rate (for NO_X-diluent monitoring systems only, in units of lb/mmBtu, rounded either to the nearest hundredth or thousandth prior to April 1, 2000 and rounded to the nearest thousandth on and after April 1, 2000), adjusted for bias if bias adjustment factor is required, as provided in § 75.24(d). The requirement to report hourly NO_X emission rates to the nearest thousandth shall not affect NO_X compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu;

(8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_X-diluent or NO_X concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to § 75.32;

(9) Method of determination for hourly average NO_X emission rate or NO_X concentration and (if applicable) for the hourly average moisture percentage, using Codes 1–55 in Table 4a of this section; and

(10) Identification codes for emissions formulas used to derive hourly average NO_X emission rate and total NO_X mass emissions, as provided in § 75.53, and (if applicable) the F-factor used to convert NO_X concentrations into emission rates.

(e) *CO_2 emission record provisions.* Except for a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) for estimating CO_2 mass emissions, the owner or operator shall record or calculate CO_2 emissions for each affected unit using one of the following methods specified in this section:

(1) If the owner or operator chooses to use a CO_2 CEMS (including an O_2 monitor and flow monitor, as specified in appendix F to this part), then the owner or operator shall record for each hour or partial hour during which the unit operates the following information for CO_2 mass emissions, as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in § 75.53 (including identification code for the moisture monitoring system, if applicable);

(ii) Date and hour;

(iii) Hourly average CO_2 concentration (in percent, rounded to the nearest tenth);

(iv) Hourly average volumetric flow rate (scfh, rounded to the nearest thousand scfh);

(v) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth), where CO_2 concentration is measured on a dry basis. If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);

(vi) Hourly average CO_2 mass emission rate (tons/hr, rounded to the nearest tenth);

(vii) Percent monitor data availability for both the CO_2 monitoring system and, if applicable, the moisture monitoring system (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32;

(viii) Method of determination for hourly average CO_2 mass emission rate and hourly average CO_2 concentration, and, if applicable, for the hourly average moisture percentage, using Codes 1–55 in Table 4a of this section;

(ix) Identification code for emissions formula used to derive hourly average CO_2 mass emission rate, as provided in § 75.53; and

(x) Indication of whether the diluent cap was used for CO_2 calculation for the hour.

(2) As an alternative to paragraph (e)(1) of this section, the owner or operator may use the procedures in § 75.13 and in appendix G to this part, and shall record daily the following information for CO_2 mass emissions:

(i) Date;

(ii) Daily combustion-formed CO_2 mass emissions (tons/day, rounded to the nearest tenth);

(iii) For coal-fired units, flag indicating whether optional procedure to adjust combustion-formed CO_2 mass emissions for carbon retained in flyash has been used and, if so, the adjustment;

(iv) For a unit with a wet flue gas desulfurization system or other controls generating CO_2, daily sorbent-related CO_2 mass emissions (tons/day, rounded to the nearest tenth); and

(v) For a unit with a wet flue gas desulfurization system or other controls generating CO_2, total daily CO_2 mass emissions (tons/day, rounded to the nearest tenth) as the sum of combustion-formed emissions and sorbent-related emissions.

(f) *Opacity records.* The owner or operator shall record opacity data as specified by the State or local air pollution control agency. If the State or local air pollution control agency does not specify recordkeeping requirements for opacity, then record the information required by paragraphs (f) (1) through (5) of this section for each affected unit, except as provided in §§ 75.14(b), (c), and (d). The owner or operator shall also keep records of all incidents of opacity monitor downtime during unit operation, including reason(s) for the monitor outage(s) and any corrective action(s) taken for opacity, as measured and reported by the continuous opacity monitoring system:

(1) Component/system identification code;

(2) Date, hour, and minute;

(3) Average opacity of emissions for each six minute averaging period (in percent opacity);

(4) If the average opacity of emissions exceeds the applicable standard, then a code indicating such an exceedance has occurred; and (5) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated according to the requirements of the procedure recommended for State Implementation Plans in appendix M to part 51 of this chapter.

(g) *Diluent record provisions.* The owner or operator of a unit using a flow monitor and an O_2 diluent monitor to determine heat input, in accordance with Equation F–17 or F–18 of appendix F to this part, or a unit that accounts for heat input using a flow monitor and a CO_2 diluent monitor (which is used only for heat input determination and is not used as a CO_2 pollutant concentration monitor) shall keep the following records for the O_2 or CO_2 diluent monitor:

(1) Component-system identification code, as provided in § 75.53;

(2) Date and hour;

(3) Hourly average diluent gas (O_2 or CO_2) concentration (in percent, rounded to the nearest tenth);

(4) Percent monitor data availability for the diluent monitor (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32; and

(5) Method of determination code for diluent gas (O_2 or CO_2) concentration data using Codes 1–55, in Table 4a of this section.

(h) *Missing data records.* The owner or operator shall record the causes of any missing data periods and the actions taken by the owner or operator to correct such causes.

41. Section 75.58 is added to subpart F to read as follows:

§ 75.58 General recordkeeping provisions for specific situations.

Before April 1, 2000, the owner or operator shall meet the requirements of either this section or § 75.55. However, the provisions of this section which support a regulatory option provided in another section of this part must be followed if that regulatory option is exercised prior to April 1, 2000. On or after April 1, 2000, the owner or operator shall meet the requirements of this section.

(a) [Reserved]

(b) *Specific parametric data record provisions for calculating substitute emissions data for units with add-on emission controls.* In accordance with § 75.34, the owner or operator of an affected unit with add-on emission controls shall either record the applicable information in paragraph (b)(3) of this section for each hour of missing SO_2 concentration data or NO_X emission rate (in addition to other information), or shall record the information in paragraph (b)(1) of this section for SO_2 or paragraph (b)(2) of this section for NO_X through an automated data acquisition and handling system, as appropriate to the type of add-on emission controls:

(1) For units with add-on SO_2 emission controls using the optional parametric monitoring procedures in appendix C to this part, for each hour of missing SO_2 concentration or volumetric flow data:

(i) The information required in § 75.54(c) or § 75.57(c) for SO_2 concentration and volumetric flow, if either one of these monitors is still operating;

(ii) Date and hour;

(iii) Number of operating scrubber modules;

(iv) Total feedrate of slurry to each operating scrubber module (gal/min);

(v) Pressure differential across each operating scrubber module (inches of water column);

(vi) For a unit with a wet flue gas desulfurization system, an in-line measure of absorber pH for each operating scrubber module;

(vii) For a unit with a dry flue gas desulfurization system, the inlet and outlet temperatures across each operating scrubber module;

(viii) For a unit with a wet flue gas desulfurization system, the percent solids in slurry for each scrubber module;

(ix) For a unit with a dry flue gas desulfurization system, the slurry feed rate (gal/min) to the atomizer nozzle;

(x) For a unit with SO_2 add-on emission controls other than wet or dry limestone, corresponding parameters approved by the Administrator;

(xi) Method of determination of SO_2 concentration and volumetric flow using Codes 1–15 in Table 4 of § 75.54 or Codes 1–55 in Table 4a of § 75.57; and

(xii) Inlet and outlet SO_2 concentration values, recorded by an SO_2 continuous emission monitoring system, and the removal efficiency of the add-on emission controls.

(2) For units with add-on NO_X emission controls using the optional parametric monitoring procedures in appendix C to this part, for each hour of missing NO_X emission rate data:

(i) Date and hour;

(ii) Inlet air flow rate (scfh, rounded to the nearest thousand);

(iii) Excess O_2 concentration of flue gas at stack outlet (percent, rounded to the nearest tenth of a percent);

(iv) Carbon monoxide concentration of flue gas at stack outlet (ppm, rounded to the nearest tenth);

(v) Temperature of flue gas at furnace exit or economizer outlet duct (°F);

(vi) Other parameters specific to NO_X emission controls (e.g., average hourly reagent feedrate);

(vii) Method of determination of NO_X emission rate using Codes 1–15 in Table 4 of § 75.54 or Codes 1–55 in Table 4a of § 75.57; and

(viii) Inlet and outlet NO_X emission rate values recorded by a NO_X continuous emission monitoring system and the removal efficiency of the add-on emission controls.

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

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

(ii) A flag indicating either that the add-on emission controls are operating properly, as evidenced by all parameters being within the ranges specified in the quality assurance/quality control program, or that the add-on emission controls are not operating properly;

(iii) For units substituting a representative SO_2 concentration during missing data periods under § 75.34(a)(2), any available inlet and outlet SO_2 concentration values recorded by an SO_2 continuous emission monitoring system; and

(iv) For units substituting a representative NO_X emission rate during missing data periods under § 75.34(a)(2), any available inlet and outlet NO_X emission rate values recorded by a continuous emission monitoring system.

(c) *Specific SO_2 emission record provisions for gas-fired or oil-fired units using optional protocol in appendix D to this part.* In lieu of recording the information in § 75.54(c) or § 75.57(c), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part for estimating SO_2 mass emissions:

(1) For each hour when the unit is combusting oil:

(i) Date and hour;

(ii) Hourly average volumetric flow rate of oil, while the unit combusts oil, with the units in which oil flow is recorded (gal/hr, scf/hr, m^3/hr, or bbl/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(iii) Sulfur content of oil sample used to determine SO_2 mass emission rate (rounded to nearest hundredth for diesel fuel or to the nearest tenth of a percent for other fuel oil) (flag value if derived from missing data procedures);

(iv) [Reserved];

(v) Mass flow rate of oil combusted each hour and method of determination (lb/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(vi) SO_2 mass emission rate from oil (lb/hr, rounded to the nearest tenth);

(vii) For units using volumetric oil flowmeters, density of oil with the units in which oil density is recorded and method of determination (flag value if derived from missing data procedures);

(viii) Gross calorific value of oil used to determine heat input and method of determination (Btu/lb) (flag value if derived from missing data procedures);

(ix) Hourly heat input rate from oil, according to procedures in appendix D to this part (mmBtu/hr, to the nearest tenth);

(x) Fuel usage time for combustion of oil during the hour (rounded up to the nearest 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)) (flag to indicate multiple/single fuel types combusted);

(xi) Monitoring system identification code;

(xii) Operating load range corresponding to gross unit load (01–20); and

(xiii) Type of oil combusted.

(2) For gas-fired units or oil-fired units using the optional protocol in appendix D to this part for daily manual oil sampling, when the unit is combusting oil, the highest sulfur content recorded from the most recent 30 daily oil samples (rounded to the nearest tenth of a percent).

(3) For gas-fired units or oil-fired units using the optional protocol in appendix D to this part, when either an assumed oil sulfur content or density value is used, or when as-delivered oil sampling is performed:

(i) Record the measured sulfur content, gross calorific value, and, if applicable, density from each fuel sample; and

(ii) Record and report the assumed sulfur content, gross calorific value, and, if applicable, density used to calculate SO_2 mass emission rate or heat input rate.

(4) For each hour when the unit is combusting gaseous fuel:

(i) Date and hour.

(ii) Hourly heat input rate from gaseous fuel, according to procedures in appendix F to this part (mmBtu/hr, rounded to the nearest tenth).

(iii) Sulfur content or SO_2 emission rate, in one of the following formats, in accordance with the appropriate procedure from appendix D to this part:

(A) Sulfur content of gas sample and method of determination (rounded to the nearest 0.1 grains/100 scf) (flag value if derived from missing data procedures); or

(B) Default SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas, or calculated SO_2 emission rate for natural gas from section 2.3.2.1.1 of appendix D to this part.

(iv) Hourly flow rate of gaseous fuel, while the unit combusts gas (100 scfh) and source of data code for gas flow rate.

(v) Gross calorific value of gaseous fuel used to determine heat input rate (Btu/100 scf) (flag value if derived from missing data procedures).

(vi) SO_2 mass emission rate due to the combustion of gaseous fuels (lb/hr).

(vii) Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest 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)) (flag to indicate multiple/single fuel types combusted).

(viii) Monitoring system identification code.

(ix) Operating load range corresponding to gross unit load (01–20).

(x) Type of gas combusted.

(5) For each oil sample or sample of diesel fuel:

(i) Date of sampling;

(ii) Sulfur content (percent, rounded to the nearest hundredth for diesel fuel and to the nearest tenth for other fuel oil);

(iii) Gross calorific value (Btu/lb); and

(iv) Density or specific gravity, if required to convert volume to mass.

(6) For each sample of gaseous fuel for sulfur content:

(i) Date of sampling; and

(ii) Sulfur content (grains/100 scf, rounded to the nearest tenth).

(7) For each sample of gaseous fuel for gross calorific value:

(i) Date of sampling; and

(ii) Gross calorific value (Btu/100 scf)

(8) For each oil sample or sample of gaseous fuel:

(i) Type of oil or gas; and

(ii) Type of sulfur sampling (using codes in tables D–4 and D–5 of appendix D to this part) and value used in calculations, and type of GCV or density sampling (using codes in tables D–4 and D–5 of appendix D to this part).

(d) *Specific NO_X emission record provisions for gas-fired peaking units or oil-fired peaking units using optional protocol in appendix E to this part.* In lieu of recording the information in paragraph § 75.54(d) or § 75.57(d), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in appendix E to this part for estimating NO_X emission rate. The owner or operator shall meet the requirements of this section, except that the requirements under paragraphs (d)(1)(vii) and (d)(2)(vii) of this section shall become applicable on the date on which the owner or operator is required to monitor, record, and report NO_X mass emissions under an applicable State or federal NO_X mass emission reduction program, if the provisions of subpart H of this part are adopted as requirements under such a program.

(1) For each hour when the unit is combusting oil:

(i) Date and hour;

(ii) Hourly average mass flow rate of oil while the unit combusts oil with the units in which oil flow is recorded (lb/hr);

(iii) Gross calorific value of oil used to determine heat input (Btu/lb);

(iv) Hourly average NO_X emission rate from combustion of oil (lb/mmBtu, rounded to the nearest hundredth);

(v) Heat input rate of oil (mmBtu/hr, rounded to the nearest tenth);

(vi) Fuel usage time for combustion of oil during the hour (rounded up to the nearest 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);

(vii) NO_X mass emissions, calculated in accordance with section 8.1 of appendix F to this part;

(viii) NO_X monitoring system identification code;

(ix) Fuel flow monitoring system identification code; and

(x) Segment identification of the correlation curve.

(2) For each hour when the unit is combusting gaseous fuel:

(i) Date and hour;

(ii) Hourly average fuel flow rate of gaseous fuel, while the unit combusts gas (100 scfh);

(iii) Gross calorific value of gaseous fuel used to determine heat input (Btu/100 scf) (flag value if derived from missing data procedures);

(iv) Hourly average NO_X emission rate from combustion of gaseous fuel (lb/mmBtu, rounded to nearest hundredth);

(v) Heat input rate from gaseous fuel, while the unit combusts gas (mmBtu/hr, rounded to the nearest tenth);

(vi) Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest 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);

(vii) NO_X mass emissions, calculated in accordance with section 8.1 of appendix F to this part;

(viii) NO_X monitoring system identification code;

(ix) Fuel flow monitoring system identification code; and

(x) Segment identification of the correlation curve.

(3) For each hour when the unit combusts multiple fuels:

(i) Date and hour;

(ii) Hourly average heat input rate from all fuels (mmBtu/hr, rounded to the nearest tenth); and

(iii) Hourly average NO_X emission rate for the unit for all fuels (lb/mmBtu, rounded to the nearest hundredth).

(4) For each hour when the unit combusts any fuel(s):

(i) For stationary gas turbines and diesel or dual-fuel reciprocating engines, hourly averages of operating parameters under section 2.3 of appendix E to this part (flag if value is outside of manufacturer's recommended range); and

(ii) For boilers, hourly average boiler O_2 reading (percent, rounded to the nearest tenth) (flag if value exceeds by more than 2 percentage points the O_2 level recorded at the same heat input during the previous NO_X emission rate test).

(5) For each fuel sample:

(i) Date of sampling;

(ii) Gross calorific value (Btu/lb for oil, Btu/100 scf for gaseous fuel); and

(iii) Density or specific gravity, if required to convert volume to mass.

(6) Flag to indicate multiple or single fuels combusted.

(e) *Specific SO_2 emission record provisions during the combustion of gaseous fuel.* (1) If SO_2 emissions are determined in accordance with the provisions in § 75.11(e)(2) during hours in which only gaseous fuel is combusted in a unit with an SO_2 CEMS, the owner or operator shall record the information in paragraph (c)(3) of this section in lieu of the information in §§ 75.54(c)(1) and (c)(3) or §§ 75.57(c)(1), (c)(3), and (c)(4), for those hours.

(2) The provisions of this paragraph apply to a unit which, in accordance with the provisions of § 75.11(e)(3), uses an SO_2 CEMS to determine SO_2 emissions during hours in which only gaseous fuel is combusted in the unit. If the unit sometimes burns only gaseous fuel that is very low sulfur fuel (as defined in § 72.2 of this chapter) as a primary and/or backup fuel and at other times combusts higher sulfur fuels, such as coal or oil, as primary and/or backup fuel(s), then the owner or operator shall keep records on-site, in a form suitable for inspection, of the type(s) of fuel(s) burned during each period of missing SO_2 data and the number of hours that each type of fuel was combusted in the unit during each missing data period. This recordkeeping requirement does not apply to an affected unit that burns very low sulfur fuel exclusively, nor does it apply to a unit that burns such gaseous fuel(s) only during unit startup.

(f) *Specific SO_2, NO_X, and CO_2 record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in § 75.19.* In lieu of recording the information in §§ 75.54(b) through (e) or §§ 75.57(b) through (e), the owner or operator shall record the following information for each affected low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c):

(1) All low mass emission units shall report for each hour:

(i) Date and hour;

(ii) Unit operating time (units using the long term fuel flow methodology report operating time to be 1);

(iii) Fuel type (pipeline natural gas, natural gas, residual oil, or diesel fuel) (note: if more than one type of fuel is combusted in the hour, indicate the fuel type which results in the highest emission factors for NO_X);

(iv) Average hourly NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth);

(v) Hourly NO_X mass emissions (lbs, rounded to the nearest tenth);

(vi) Hourly SO_2 mass emissions (lbs, rounded to the nearest tenth);

(vii) Hourly CO_2 mass emissions (tons, rounded to the nearest tenth);

(viii) Hourly calculated unit heat input in mmBtu;

(ix) Hourly unit output in gross load or steam load;

(x) The method of determining hourly heat input: unit maximum rated heat input, unit long term fuel flow or group long term fuel flow;

(xi) The method of determining NO_X emission rate used for the hour: default based on fuel combusted, unit specific default based on testing or historical data, group default based on representative testing of identical units, unit specific based on testing of a unit with NO_X controls operating, or missing data value; and

(xii) Control status of the unit.

(2) Low mass emission units using the optional long term fuel flow methodology to determine unit heat input shall report for each quarter:

(i) Type of fuel;

(ii) Beginning date and hour of long term fuel flow measurement period;

(iii) End date and hour of long term fuel flow period;

(iv) Quantity of fuel measured;

(v) Units of measure;

(vi) Fuel GCV value used to calculate heat input;

(vii) Units of GCV;

(viii) Method of determining fuel GCV used;

(ix) Method of determining fuel flow over period;

(x) Component-system identification code;

(xi) Quarter and year;

(xii) Total heat input (mmBtu); and

(xiii) Operating hours in period.

42. Section 75.59 is added to subpart F to read as follows:

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

Before April 1, 2000, the owner or operator shall meet the requirements of this section or § 75.56. However, the provisions of this section which support a regulatory option provided in another section of this part must be followed if that regulatory option is exercised prior to April 1, 2000. On or after April 1, 2000, the owner or operator shall meet the requirements of this section.

(a) *Continuous emission or opacity monitoring systems.* The owner or operator shall record the applicable information in this section for each certified monitor or certified monitoring system (including certified backup monitors) measuring and recording emissions or flow from an affected unit.

(1) For each SO_2 or NO_X pollutant concentration monitor, flow monitor, CO_2 pollutant concentration monitor (including O_2 monitors used to determine CO_2 emissions), or diluent gas monitor (including wet- and dry-basis O_2 monitors used to determine percent moisture), the owner or operator shall record the following for all daily and 7-day calibration error tests and all off-line calibration demonstrations, including any follow-up tests after corrective action:

(i) Component-system identification code;

(ii) Instrument span and span scale;

(iii) Date and hour;

(iv) Reference value (i.e., calibration gas concentration or reference signal value, in ppm or other appropriate units);

(v) Observed value (monitor response during calibration, in ppm or other appropriate units);

(vi) Percent calibration error (rounded to the nearest tenth of a percent) (flag if using alternative performance specification for low emitters or differential pressure flow monitors);

(vii) Calibration gas level;

(viii) Test number and reason for test;

(ix) For 7-day calibration tests for certification or recertification, a certification from the cylinder gas vendor or CEMS vendor that calibration gas, as defined in § 72.2 of this chapter and appendix A to this part, was used to conduct calibration error testing;

(x) Description of any adjustments, corrective actions, or maintenance prior to a passed test or following a failed test; and

(xi) For the qualifying test for off-line calibration, the owner or operator shall indicate whether the unit is off-line or on-line.

(2) For each flow monitor, the owner or operator shall record the following for all daily interference checks, including any follow-up tests after corrective action.

(i) Component-system identification code;

(ii) Date and hour;

(iii) Code indicating whether monitor passes or fails the interference check; and

(iv) Description of any adjustments, corrective actions, or maintenance prior to a passed test or following a failed test.

(3) For each SO_2 or NO_X pollutant concentration monitor, CO_2 pollutant concentration monitor (including O_2 monitors used to determine CO_2 emissions), or diluent gas monitor (including wet- and dry-basis O_2 monitors used to determine percent moisture), the owner or operator shall record the following for the initial and all subsequent linearity check(s), including any follow-up tests after corrective action.

(i) Component-system identification code;

(ii) Instrument span and span scale;

(iii) Calibration gas level;

(iv) Date and time (hour and minute) of each gas injection at each calibration gas level;

(v) Reference value (i.e., reference gas concentration for each gas injection at each calibration gas level, in ppm or other appropriate units);

(vi) Observed value (monitor response to each reference gas injection at each calibration gas level, in ppm or other appropriate units);

(vii) Mean of reference values and mean of measured values at each calibration gas level;

(viii) Linearity error at each of the reference gas concentrations (rounded to nearest tenth of a percent) (flag if using alternative performance specification);

(ix) Test number and reason for test (flag if aborted test); and

(x) Description of any adjustments, corrective action, or maintenance prior to a passed test or following a failed test.

(4) For each differential pressure type flow monitor, the owner or operator shall record items in paragraphs (a)(4) (i) through (v) of this section, for all quarterly leak checks, including any follow-up tests after corrective action. For each flow monitor, the owner or operator shall record items in paragraphs (a)(4) (vi) and (vii) for all flow-to-load ratio and gross heat rate tests:

(i) Component-system identification code.

(ii) Date and hour.

(iii) Reason for test.

(iv) Code indicating whether monitor passes or fails the quarterly leak check.

(v) Description of any adjustments, corrective actions, or maintenance prior to a passed test or following a failed test.

(vi) Test data from the flow-to-load ratio or gross heat rate (GHR) evaluation, including:

(A) Monitoring system identification code;

(B) Calendar year and quarter;

(C) Indication of whether the test is a flow-to-load ratio or gross heat rate evaluation;

(D) Indication of whether bias adjusted flow rates were used;

(E) Average absolute percent difference between reference ratio (or GHR) and hourly ratios (or GHR values);

(F) Test result;

(G) Number of hours used in final quarterly average;

(H) Number of hours exempted for use of a different fuel type;

(I) Number of hours exempted for load ramping up or down;

(J) Number of hours exempted for scrubber bypass;

(K) Number of hours exempted for hours preceding a normal-load flow RATA;

(L) Number of hours exempted for hours preceding a successful diagnostic test, following a documented monitor repair or major component replacement; and

(M) Number of hours excluded for flue gases discharging simultaneously thorough a main stack and a bypass stack.

(vii) Reference data for the flow-to-load ratio or gross heat rate evaluation, including (as applicable):

(A) Reference flow RATA end date and time;

(B) Test number of the reference RATA;

(C) Reference RATA load and load level;

(D) Average reference method flow rate during reference flow RATA;

(E) Reference flow/load ratio;

(F) Average reference method diluent gas concentration during flow RATA and diluent gas units of measure;

(G) Fuel specific F_d -or F_c-factor during flow RATA and F-factor units of measure;

(H) Reference gross heat rate value;

(I) Monitoring system identification code;

(J) Average hourly heat input rate during RATA;

(K) Average gross unit load; and

(L) Operating load level.

(5) For each SO_2 pollutant concentration monitor, flow monitor, each CO_2 pollutant concentration monitor (including any O_2 concentration monitor used to determine CO_2 mass emissions or heat input), each NO_X-diluent continuous emission monitoring system, each SO_2-diluent continuous emission monitoring system, each NO_X concentration monitoring system, each diluent gas (O_2 or CO_2) monitor used to determine heat input, each moisture monitoring system, and each approved alternative monitoring system, the owner or operator shall record the following information for the initial and all subsequent relative accuracy test audits:

(i) Reference method(s) used.

(ii) Individual test run data from the relative accuracy test audit for the SO_2 concentration monitor, flow monitor, CO_2 pollutant concentration monitor, NO_X-diluent continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, diluent gas (O_2 or CO_2) monitor used to determine heat input, NO_X concentration monitoring system, moisture monitoring system, or approved alternative monitoring system, including:

(A) Date, hour, and minute of beginning of test run;

(B) Date, hour, and minute of end of test run;

(C) Monitoring system identification code;

(D) Test number and reason for test;

(E) Operating load level (low, mid, high, or normal, as appropriate) and number of load levels comprising test;

(F) Normal load indicator for flow RATAs (except for peaking units);

(G) Units of measure;

(H) Run number;

(I) Run value from CEMS being tested, in the appropriate units of measure;

(J) Run value from reference method, in the appropriate units of measure;

(K) Flag value (0, 1, or 9, as appropriate) indicating whether run has been used in calculating relative accuracy and bias values or whether the test was aborted prior to completion;

(L) Average gross unit load, expressed as a total gross unit load, rounded to the nearest MWe, or as steam load, rounded to the nearest thousand lb/hr); and

(M) Flag to indicate whether an alternative performance specification has been used.

(iii) Calculations and tabulated results, as follows:

(A) Arithmetic mean of the monitoring system measurement values, of the reference method values, and of their differences, as specified in Equation A–7 in appendix A to this part;

(B) Standard deviation, as specified in Equation A–8 in appendix A to this part;

(C) Confidence coefficient, as specified in Equation A–9 in appendix A to this part;

(D) Statistical ''t'' value used in calculations;

(E) Relative accuracy test results, as specified in Equation A–10 in appendix A to this part. For multi-level flow monitor tests the relative accuracy test results shall be recorded at each load level tested. Each load level shall be expressed as a total gross unit load, rounded to the nearest MWe, or as steam load, rounded to the nearest thousand lb/hr;

(F) Bias test results as specified in section 7.6.4 in appendix A to this part; and

(G) Bias adjustment factor from Equation A–12 in appendix A to this part for any monitoring system that failed the bias test (except as otherwise provided in section 7.6.5 of appendix A to this part) and 1.000 for any monitoring system that passed the bias test.

(iv) Description of any adjustment, corrective action, or maintenance prior to a passed test or following a failed or aborted test.

(v) F-factor value(s) used to convert NO_X pollutant concentration and diluent gas (O_2 or CO_2) concentration measurements into NO_X emission rates (in lb/mmBtu), heat input or CO_2 emissions.

(vi) For flow monitors, the equation used to linearize the flow monitor and the numerical values of the polynomial coefficients or K factor(s) of that equation.

(vii) For moisture monitoring systems, the coefficient or ''K'' factor or other mathematical algorithm used to adjust the monitoring system with respect to the reference method.

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

(i) Component-system identification code;

(ii) Date;

(iii) Start and end times;

(iv) Upscale and downscale cycle times for each component;

(v) Stable start monitor value;

(vi) Stable end monitor value;

(vii) Reference value of calibration gas(es);

(viii) Calibration gas level;

(ix) Cycle time result for the entire system;

(x) Reason for test; and

(xi) Test number.

(7) In addition to the information in paragraph (a)(5) of this section, the owner or operator shall record, for each relative accuracy test audit, supporting information sufficient to substantiate compliance with all applicable sections and appendices in this part. Unless otherwise specified in this part or in an applicable test method, the information in paragraphs (a)(7)(i) through (a)(7)(vi) may be recorded either in hard copy format, electronic format or a combination of the two, and the owner or operator shall maintain this information in a format suitable for inspection and audit purposes. This RATA supporting information shall include, but shall not be limited to, the following data elements:

(i) For each RATA using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to determine volumetric flow rate:

(A) Information indicating whether or not the location meets requirements of Method 1 in appendix A to part 60 of this chapter; and

(B) Information indicating whether or not the equipment passed the required leak checks.

(ii) For each run of each RATA using Reference Method 2 (or its allowable alternatives in appendix A to part 60 of this chapter) to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):

(A) Operating load level (low, mid, high, or normal, as appropriate);

(B) Number of reference method traverse points;

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

(D) Barometric pressure at test port (inches of mercury);

(E) Stack static pressure (inches of H_2O);

(F) Absolute stack gas pressure (inches of mercury);

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

(H) CO_2 and O_2 reference method used;

(I) Moisture content of stack gas (percent H_2O);

(J) Molecular weight of stack gas, dry basis (lb/lb-mole);

(K) Molecular weight of stack gas, wet basis (lb/lb-mole);

(L) Stack diameter (or equivalent diameter) at the test port (ft);

(M) Average square root of velocity head of stack gas (inches of H_2O) for the run;

(N) Stack or duct cross-sectional area at test port (ft^2);

(O) Average velocity (ft/sec);

(P) Total volumetric flow rate (scfh, wet basis);

(Q) Flow rate reference method used;

(R) Average velocity, adjusted for wall effects;

(S) Calculated (site-specific) wall effects adjustment factor determined during the run, and, if different, the wall effects adjustment factor used in the calculations; and

(T) Default wall effects adjustment factor used.

(iii) For each traverse point of each run of each RATA using Reference Method 2 (or its allowable alternatives in appendix A to part 60 of this chapter) to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):

(A) Reference method probe type;

(B) Pressure measurement device type;

(C) Traverse point ID;

(D) Probe or pitot tube calibration coefficient;

(E) Date of latest probe or pitot tube calibration;

(F) Velocity differential pressure at traverse point (inches of H_2O);

(G) T_S, stack temperature at the traverse point (°F);

(H) Composite (wall effects) traverse point identifier;

(I) Number of points included in composite traverse point;

(J) Yaw angle of flow at traverse point (degrees);

(K) Pitch angle of flow at traverse point (degrees);

(L) Calculated velocity at traverse point both accounting and not accounting for wall effects (ft/sec); and

(M) Probe identification number.

(iv) For each RATA using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO_2, NO_X, CO_2, or O_2 concentration:

(A) Pollutant or diluent gas being measured;

(B) Span of reference method analyzer;

(C) Type of reference method system (e.g., extractive or dilution type);

(D) Reference method dilution factor (dilution type systems, only);

(E) Reference gas concentrations (zero, mid, and high gas levels) used for the 3-point pre-test analyzer calibration error test (or, for dilution type reference method systems, for the 3-point pre-test system calibration error test) and for any subsequent recalibrations;

(F) Analyzer responses to the zero-, mid-, and high-level calibration gases during the 3-point pre-test analyzer (or system) calibration error test and during any subsequent recalibration(s);

(G) Analyzer calibration error at each gas level (zero, mid, and high) for the 3-point pre-test analyzer (or system) calibration error test and for any subsequent recalibration(s) (percent of span value);

(H) Upscale gas concentration (mid or high gas level) used for each pre-run or post-run system bias check or (for dilution type reference method systems) for each pre-run or post-run system calibration error check;

(I) Analyzer response to the calibration gas for each pre-run or post-run system bias (or system calibration error) check;

(J) The arithmetic average of the analyzer responses to the zero-level gas, for each pair of pre- and post-run system bias (or system calibration error) checks;

(K) The arithmetic average of the analyzer responses to the upscale calibration gas, for each pair of pre- and post-run system bias (or system calibration error) checks;

(L) The results of each pre-run and each post-run system bias (or system calibration error) check using the zero-level gas (percentage of span value);

(M) The results of each pre-run and each post-run system bias (or system calibration error) check using the upscale calibration gas (percentage of span value);

(N) Calibration drift and zero drift of analyzer during each RATA run (percentage of span value);

(O) Moisture basis of the reference method analysis;

(P) Moisture content of stack gas, in percent, during each test run (if needed to convert to moisture basis of CEMS being tested);

(Q) Unadjusted (raw) average pollutant or diluent gas concentration for each run;

(R) Average pollutant or diluent gas concentration for each run, corrected for calibration bias (or calibration error) and, if applicable, corrected for moisture;

(S) The F-factor used to convert reference method data to units of lb/mmBtu (if applicable);

(T) Date(s) of the latest analyzer interference test(s);

(U) Results of the latest analyzer interference test(s);

(V) Date of the latest NO_2 to NO conversion test (Method 7E only);

(W) Results of the latest NO_2 to NO conversion test (Method 7E only); and

(X) For each calibration gas cylinder used during each RATA, record the cylinder gas vendor, cylinder number, expiration date, pollutant(s) in the cylinder, and certified gas concentration(s).

(v) For each test run of each moisture determination using Method 4 in appendix A to part 60 of this chapter (or its allowable alternatives), whether the determination is made to support a gas RATA, to support a flow RATA, or to quality assure the data from a continuous moisture monitoring system, record the following data elements (as applicable to the moisture measurement method used):

(A) Test number;

(B) Run number;

(C) The beginning date, hour, and minute of the run;

(D) The ending date, hour, and minute of the run;

(E) Unit operating level (low, mid, high, or normal, as appropriate);

(F) Moisture measurement method;

(G) Volume of H_2O collected in the impingers (ml);

(H) Mass of H_2O collected in the silica gel (g);

(I) Dry gas meter calibration factor;

(J) Average dry gas meter temperature (°F);

(K) Barometric pressure (inches of mercury);

(L) Differential pressure across the orifice meter (inches of H_2O);

(M) Initial and final dry gas meter readings (ft^3);

(N) Total sample gas volume, corrected to standard conditions (dscf); and

(O) Percentage of moisture in the stack gas (percent H_2O).

(vi) The raw data and calculated results for any stratification tests performed in accordance with sections 6.5.6.1 through 6.5.6.3 of appendix A to this part.

(8) For each certified continuous emission monitoring system, continuous opacity monitoring system, or alternative monitoring system, the date and description of each event which requires recertification of the system and the date and type of each test performed to recertify the system in accordance with § 75.20(b).

(9) When hardcopy relative accuracy test reports, certification reports, recertification reports, or semiannual or annual reports for gas or flow rate CEMS are required or requested under § 75.60(b)(6) or § 75.63, the reports shall include, at a minimum, the following elements (as applicable to the type(s) of test(s) performed):

(i) Summarized test results.

(ii) DAHS printouts of the CEMS data generated during the calibration error, linearity, cycle time, and relative accuracy tests.

(iii) For pollutant concentration monitor or diluent monitor relative accuracy tests at normal operating load:

(A) The raw reference method data from each run, i.e., the data under paragraph (a)(7)(iv)(Q) of this section (usually in the form of a computerized printout, showing a series of one-minute readings and the run average);

(B) The raw data and results for all required pre-test, post-test, pre-run and post-run quality assurance checks (i.e., calibration gas injections) of the reference method analyzers, i.e., the data under paragraphs (a)(7)(iv)(E) through (a)(7)(iv)(N) of this section;

(C) The raw data and results for any moisture measurements made during the relative accuracy testing, i.e., the data under paragraphs (a)(7)(v)(A) through (a)(7)(v)(O) of this section; and

(D) Tabulated, final, corrected reference method run data (i.e., the actual values used in the relative accuracy calculations), along with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced.

(iv) For relative accuracy tests for flow monitors:

(A) The raw flow rate reference method data, from Reference Method 2 (or its allowable alternatives) under appendix A to part 60 of this chapter, including auxiliary moisture data (often in the form of handwritten data sheets), i.e., the data under paragraphs (a)(7)(ii)(A) through (a)(7)(ii)(T), paragraphs (a)(7)(iii)(A) through (a)(7)(iii)(M), and, if applicable, paragraphs (a)(7)(v)(A) through (a)(7)(v)(O) of this section; and

(B) The tabulated, final volumetric flow rate values used in the relative accuracy calculations (determined from the flow rate reference method data and other necessary measurements, such as moisture, stack temperature and pressure), along with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced.

(v) Calibration gas certificates for the gases used in the linearity, calibration error, and cycle time tests and for the calibration gases used to quality assure the gas monitor reference method data during the relative accuracy test audit.

(vi) Laboratory calibrations of the source sampling equipment.

(vii) A copy of the test protocol used for the CEMS certifications or recertifications, including narrative that explains any testing abnormalities, problematic sampling, and analytical conditions that required a change to the test protocol, and/or solutions to technical problems encountered during the testing program.

(viii) Diagrams illustrating test locations and sample point locations (to verify that locations are consistent with information in the monitoring plan). Include a discussion of any special traversing or measurement scheme. The discussion shall also confirm that sample points satisfy applicable acceptance criteria.

(ix) Names of key personnel involved in the test program, including test team members, plant contacts, agency representatives and test observers on site.

(10) Whenever reference methods are used as backup monitoring systems pursuant to § 75.20(d)(3), the owner or operator shall record the following information:

(i) For each test run using Reference Method 2 (or its allowable alternatives in appendix A to part 60 of this chapter) to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):

(A) Unit or stack identification number;

(B) Reference method system and component identification numbers;

(C) Run date and hour;

(D) The data in paragraph (a)(7)(ii) of this section, except for paragraphs (a)(7)(ii)(A), (F), (H), (L) and (Q) through (T); and

(E) The data in paragraph (a)(7)(iii)(A), except on a run basis.

(ii) For each reference method test run using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO_2, NO_X, CO_2, or O_2 concentration:

(A) Unit or stack identification number;

(B) The reference method system and component identification numbers;

(C) Run number;

(D) Run start date and hour;

(E) Run end date and hour;

(F) The data in paragraphs (a)(7)(iv)(B) through (I) and (L) through (O); and (G) Stack gas density adjustment factor (if applicable).

(iii) For each hour of each reference method test run using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO_2, NO_X, CO_2, or O_2 concentration:

(A) Unit or stack identification number;

(B) The reference method system and component identification numbers;

(C) Run number;

(D) Run date and hour;

(E) Pollutant or diluent gas being measured;

(F) Unadjusted (raw) average pollutant or diluent gas concentration for the hour; and

(G) Average pollutant or diluent gas concentration for the hour, adjusted as appropriate for moisture, calibration bias (or calibration error) and stack gas density.

(11) For each other quality-assurance test or other quality assurance activity, the owner or operator shall record the following (as applicable):

(i) Component/system identification code;

(ii) Parameter;

(iii) Test or activity completion date and hour;

(iv) Test or activity description;

(v) Test result;

(vi) Reason for test; and

(vii) Test code.

(12) For each request for a quality assurance test extension or exemption, for any loss of exempt status, and for each single-load flow RATA claim pursuant to section 2.3.1.3(c)(3) of appendix B to this part, the owner or operator shall record the following (as applicable):

(i) For a RATA deadline extension or exemption request:

(A) Monitoring system identification code;

(B) Date of last RATA;

(C) RATA expiration date without extension;

(D) RATA expiration date with extension;

(E) Type of RATA extension of exemption claimed or lost;

(F) Year to date hours of usage of fuel other than very low sulfur fuel;

(G) Year to date hours of non-redundant back-up CEMS usage at the unit/stack; and

(H) Quarter and year.

(ii) For a linearity test or flow-to-load ratio test quarterly exemption:

(A) Component-system identification code;

(B) Type of test;

(C) Basis for exemption;

(D) Quarter and year; and

(E) Span scale.

(iii) For a quality assurance test extension claim based on a grace period:

(A) Component-system identification code;

(B) Type of test;

(C) Beginning of grace period;

(D) Date and hour of completion of required quality assurance test;

(E) Number of unit or stack operating hours from the beginning of the grace period to the completion of the quality assurance test or the maximum allowable grace period; and

(F) Date and hour of end of grace period.

(iv) For a fuel flowmeter accuracy test extension:

(A) Component-system identification code;

(B) Date of last accuracy test;

(C) Accuracy test expiration date without extension;

(D) Accuracy test expiration date with extension;

(E) Type of extension; and

(F) Quarter and year.

(v) For a single-load flow RATA claim:

(A) Monitoring system identification code;

(B) Ending date of last annual flow RATA;

(C) The relative frequency (percentage) of unit or stack operation at each load level (low, mid, and high) since the previous annual flow RATA, to the nearest 0.1 percent.

(D) End date of the historical load data collection period; and

(E) Indication of the load level (low, mid or high) claimed for the single-load flow RATA.

(13) An indication that data have been excluded from a periodic span and range evaluation of an SO_2 or NO_X monitor under section 2.1.1.5 or 2.1.2.5 of appendix A to this part and the reason(s) for excluding the data. For purposes of reporting under § 75.64(a)(2), this information shall be reported with the quarterly report as descriptive text consistent with § 75.64(g).

(b) *Excepted monitoring systems for gas-fired and oil-fired units.* The owner or operator shall record the applicable information in this section for each excepted monitoring system following the requirements of appendix D to this part or appendix E to this part for determining and recording emissions from an affected unit.

(1) For certification and quality assurance testing of fuel flowmeters tested against a reference fuel flow rate (i.e., flow rate from another fuel flowmeter under section 2.1.5.2 of appendix D to this part or flow rate from a procedure according to a standard incorporated by reference under section 2.1.5.1 of appendix D to this part):

(i) Unit or common pipe header identification code;

(ii) Component and system identification codes of the fuel flowmeter being tested;

(iii) Date and hour of test completion, for a test performed in-line at the unit;

(iv) Date and hour of flowmeter reinstallation, for laboratory tests;

(v) Test number;

(vi) Upper range value of the fuel flowmeter;

(vii) Flowmeter measurements during accuracy test (and mean of values), including units of measure;

(viii) Reference flow rates during accuracy test (and mean of values), including units of measure;

(ix) Level of fuel flowrate test during runs (low, mid or high);

(x) Average flowmeter accuracy for low and high fuel flowrates and highest flowmeter accuracy of any level designated as mid, expressed as a percent of upper range value;

(xi) Indicator of whether test method was a lab comparison to reference meter or an in-line comparison against a master meter;

(xii) Test result (aborted, pass, or fail); and

(xiii) Description of fuel flowmeter calibration specification or procedure (in the certification application, or periodically if a different method is used for annual quality assurance testing).

(2) For each transmitter or transducer accuracy test for an orifice-, nozzle-, or venturi-type flowmeter used under section 2.1.6 of appendix D to this part:

(i) Component and system identification codes of the fuel flowmeter being tested;

(ii) Completion date and hour of test;

(iii) For each transmitter or transducer: transmitter or transducer type (differential pressure, static pressure, or temperature); the full-scale value of the transmitter or transducer, transmitter input (pre-calibration) prior to accuracy test, including units of measure; and expected transmitter output during accuracy test (reference value from NIST-traceable equipment), including units of measure;

(iv) For each transmitter or transducer tested: output during accuracy test, including units of measure; transmitter or transducer accuracy as a percent of the full-scale value; and transmitter output level as a percent of the full-scale value;

(v) Average flowmeter accuracy at low and high fuel flowrates and highest flowmeter accuracy of any level designated as mid fuel flowrate, expressed as a percent of upper range value;

(vi) Test result (pass, fail, or aborted);

(vii) Test number; and

(viii) Accuracy determination methodology.

(3) For each visual inspection of the primary element or transmitter or transducer accuracy test for an orifice-, nozzle-, or venturi-type flowmeter under sections 2.1.6.1 through 2.1.6.4 of appendix D to this part:

(i) Date of inspection/test;

(ii) Hour of completion of inspection/test;

(iii) Component and system identification codes of the fuel flowmeter being inspected/tested; and

(iv) Results of inspection/test (pass or fail).

(4) For fuel flowmeters that are tested using the optional fuel flow-to-load ratio procedures of section 2.1.7 of appendix D to this part:

(i) Test data for the fuel flowmeter flow-to-load ratio or gross heat rate check, including:

(A) Component/system identification code;

(B) Calendar year and quarter;

(C) Indication of whether the test is for fuel flow-to-load ratio or gross heat rate;

(D) Quarterly average absolute percent difference between baseline for fuel flow-to-load ratio (or baseline gross heat rate and hourly quarterly fuel flow-to-load ratios (or gross heat rate value);

(E) Test result;

(F) Number of hours used in the analysis;

(G) Number of hours excluded due to co-firing;

(H) Number of hours excluded due to ramping; and

(I) Number of hours excluded in lower 25.0 percent range of operation.

(ii) Reference data for the fuel flowmeter flow-to-load ratio or gross heat rate evaluation, including:

(A) Completion date and hour of most recent primary element inspection;

(B) Completion date and hour of most recent flowmeter or transmitter accuracy test;

(C) Beginning date and hour of baseline period;

(D) Completion date and hour of baseline period;

(E) Average fuel flow rate, in 100 scfh for gas and lb/hr for oil;

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

(G) Baseline fuel flow-to-load ratio, in the appropriate units of measure (if using fuel flow-to-load ratio);

(H) Baseline gross heat rate if using gross heat rate, in the appropriate units of measure (if using gross heat rate check);

(I) Number of hours excluded from baseline data due to ramping;

(J) Number of hours excluded from baseline data in lower 25.0 percent of range of operation;

(K) Average hourly heat input rate; and

(L) Flag indicating baseline data collection is in progress and that fewer than four calendar quarters have elapsed since the quarter of the last flowmeter QA test.

(5) For gas-fired peaking units or oil-fired peaking units using the optional procedures of appendix E to this part, for each initial performance, periodic, or quality assurance/quality control-related test:

(i) For each run of emission data, record the following data:

(A) Unit or common pipe identification code;

(B) Monitoring system identification code for appendix E system;

(C) Run start date and time;

(D) Run end date and time;

(E) Total heat input during the run (mmBtu);

(F) NO_X emission rate (lb/mmBtu) from reference method;

(G) Response time of the O_2 and NO_X reference method analyzers;

(H) Type of fuel(s) combusted during the run;

(I) Heat input rate (mmBtu/hr) during the run;

(J) Test number;

(K) Run number;

(L) Operating level during the run;

(M) NO_X concentration recorded by the reference method during the run;

(N) Diluent concentration recorded by the reference method during the run; and

(O) Moisture measurement for the run (if applicable).

(ii) For each run during which oil or mixed fuels are combusted record the following data:

(A) Unit or common pipe identification code;

(B) Monitoring system identification code for oil monitoring system;

(C) Run start date and time;

(D) Run end date and time;

(E) Mass flow or volumetric flow of oil, in the units of measure for the type of fuel flowmeter;

(F) Gross calorific value of oil in the appropriate units of measure;

(G) Density of fuel oil in the appropriate units of measure (if density is used to convert oil volume to mass);

(H) Hourly heat input (mmBtu) during run from oil;

(I) Test number;

(J) Run number; and

(K) Operating level during the run.

(iii) For each run during which gas or mixed fuels are combusted record the following data:

(A) Unit or common pipe identification code;

(B) Monitoring system identification code for gas monitoring system;

(C) Run start date and time;

(D) Run end date and time;

(E) Volumetric flow of gas (100 scf);

(F) Gross calorific value of gas (Btu/100 scf);

(G) Hourly heat input (mmBtu) during run from gas;

(H) Test number;

(I) Run number; and

(J) Operating level during the run.

(iv) For each operating level at which runs were performed:

(A) Completion date and time of last run for operating level;

(B) Type of fuel(s) combusted during test;

(C) Average heat input rate at that operating level (mmBtu/hr);

(D) Arithmetic mean of NO_X emission rates from reference method run at this level;

(E) F-factor used in calculations of NO_X emission rate at that operating level;

(F) Unit operating parametric data related to NO_X formation for that unit type (e.g., excess O_2 level, water/fuel ratio);

(G) Test number; and

(H) Operating level for runs.

(c) For units with add-on SO_2 or NO_X emission controls following the provisions of § 75.34(a)(1) or (a)(2), the owner or operator shall keep the following records on-site in the quality assurance/quality control plan required by section 1 of appendix B to this part:

(1) A list of operating parameters for the add-on emission controls, including parameters in § 75.55(b) or § 75.58(b), appropriate to the particular installation of add-on emission controls; and

(2) The range of each operating parameter in the list that indicates the add-on emission controls are properly operating.

(d) *Excepted monitoring for low mass emissions units under § 75.19(c)(1)(iv).* For oil-and gas-fired units using the optional SO_2, NO_X and CO_2 emissions calculations for low mass emission units under § 75.19, the owner or operator shall record the following information for tests performed to determine a fuel and unit-specific default as provided in § 75.19(c)(1)(iv):

(1) For each run of each test performed under section 2.1 of appendix E to this part, record the following data:

(i) Unit or common pipe identification code;

(ii) Run start date and time;

(iii) Run end date and time;

(iv) NO_X emission rate (lb/mmBtu) from reference method;

(v) Response time of the O_2 and NO_X reference method analyzers;

(vi) Type of fuel(s) combusted during the run;

(vii) Test number;

(viii) Run number;

(ix) Operating level during the run;

(x) NO_X concentration recorded by the reference method during the run;

(xi) Diluent concentration recorded by the reference method during the run;

(xii) Moisture measurement for the run (if applicable);

(xiii) An indicator that the resulting NO_X emission rate is the highest NO_X emission rate record during any run of the test (if appropriate);

(xiv) The default NO_X emission rate (highest NO_X emission rate value during the test multiplied by 1.15);

(xv) An indicator that control equipment was operating or not operating during each run of the test; and

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

(2) For each unit in a group of identical units qualifying for reduced testing under § 75.19(c)(1)(iv)(B), record the following data:

(i) The unique group identification code assigned to the group. This code must include the ORIS code of one of the units in the group;

(ii) The ORIS code or facility identification code for the unit;

(iii) The plant name of the facility at which the unit is located, consistent with the facility's monitoring plan;

(iv) The identification code for the unit, consistent with the facility's monitoring plan;

(v) A record of whether or not the unit underwent fuel and unit-specific testing for purposes of establishing a fuel and unit-specific NO_X emission rate for purposes of § 75.19;

(vi) The completion date of the fuel and unit-specific test performed for purposes of establishing a fuel and unit-specific NO_X emission rate for purposes of § 75.19;

(vii) The fuel and unit-specific NO_X default rate established for the group of identical units under § 75.19;

(viii) The type of fuel combusted for the units during testing and represented by the resulting default NO_X emission rate;

(ix) The control status for the units during testing and represented by the resulting default NO_X emission rate;

(x) Documentation supporting the qualification of all units in the group for reduced testing based on the criteria established in §§ 75.19(c)(1)(iv)(B)(*1*) and (*3*); and

(xi) Purpose of group tests.

Subpart G—Reporting Requirements

43. Section 75.60 is amended by revising paragraphs (a), (b)(1), and (b)(2) and by adding new paragraphs (b)(3), (b)(4), (b)(5) and (b)(6) to read as follows:

§ 75.60 General provisions.

(a) The designated representative for any affected unit subject to the requirements of this part shall comply with all reporting requirements in this section and with the signatory requirements of § 72.21 of this chapter for all submissions.

(b) * * *

(1) *Initial certifications.* The designated representative shall submit initial certification applications according to § 75.63.

(2) *Recertifications.* The designated representative shall submit recertification applications according to § 75.63.

(3) *Monitoring plans.* The designated representative shall submit monitoring plans according to § 75.62.

(4) *Electronic quarterly reports.* The designated representative shall submit electronic quarterly reports according to § 75.64.

(5) *Other petitions and communications.* The designated representative shall submit petitions, correspondence, application forms, designated representative signature, and petition-related test results in hardcopy to the Administrator. Additional petition requirements are specified in §§ 75.66 and 75.67.

(6) *Semiannual or annual RATA 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 RATA report within 45 days after completing a required semiannual or annual RATA according to section 2.3.1 of appendix B 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(a)(9) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the RATA report.

* * * * *

44. Section 75.61 is amended by revising paragraphs (a) introductory text, (a)(1) introductory text, and (b), by adding a new sentence to the end of paragraph (a)(6)(ii), and by adding a new paragraph (a)(1)(iv) to read as follows:

§ 75.61 Notifications.

(a) *Submission.* The designated representative for an affected unit (or owner or operator, as specified) shall submit notice to the Administrator, to the appropriate EPA Regional Office, and to the applicable State and local air pollution control agencies for the following purposes, as required by this part.

(1) *Initial certification and recertification test notifications.* The owner or operator or designated representative for an affected unit shall submit written notification of initial certification tests, recertification tests, and revised test dates as specified in

§ 75.20 for continuous emission monitoring systems, for alternative monitoring systems under subpart E of this part, or for excepted monitoring systems under appendix E to this part, except as provided in paragraphs (a)(1)(iii), (a)(1)(iv) and (a)(4) of this section and except for testing only of the data acquisition and handling system.

* * * * *

(iv) *Waiver from notification requirements.* The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may issue a waiver from the notification requirement of paragraph (a)(1) of this section, for a unit or a group of units, for one or more recertification tests. The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may also discontinue the waiver and reinstate the notification requirement of paragraph (a)(1) of this section for future recertification tests of a unit or a group of units.

* * * * *

(6) * * *

(ii) * * * The reporting requirements of this paragraph (a)(6)(ii) also shall apply if the designated representative of a unit is exempt from certifying a fuel flowmeter for use during the combustion of emergency fuel under section 2.1.4.3 of appendix D to this part.

(b) The owner or operator or designated representative shall submit notification of certification tests and recertification tests for continuous opacity monitoring systems as specified in § 75.20(c)(8) to the State or local air pollution control agency.

* * * * *

45. Section 75.62 is amended by revising the title of the section and revising paragraphs (a) and (c) to read as follows:

§ 75.62 Monitoring plan submittals.

(a) *Submission.*—(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 test; at the time of recertification application submission; and in each electronic quarterly report.

(2) *Hardcopy.* The designated representative shall submit all of the hardcopy information required under § 75.53 to the appropriate EPA Regional Office and the appropriate State and/or local air pollution control agency prior to initial certification. Thereafter, the designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information as follows: no later than 45 days prior to the initial certification test; with any recertification application, if a hardcopy monitoring plan change is associated with the recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to § 75.53(b). 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.

* * * * *

(c) *Format.* The designated representative shall submit each monitoring plan in a format specified by the Administrator.

46. Section 75.63 is revised to read as follows:

§ 75.63 Initial certification or recertification application submittals.

(a) *Submission.* The designated representative for an affected unit or a combustion source shall submit applications and reports as follows:

(1) *Initial certifications.* (i) Within 45 days after completing all initial certification tests, submit 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.

(ii) Within 45 days after completing all initial certification tests, submit the hardcopy information required by paragraph (b)(2) to the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency.

(iii) 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:

(A) To the Administrator, the electronic information required by paragraph (b)(1)(i), the hardcopy information required by paragraph (b)(2), and a hardcopy certification application form (EPA form 7610–14); and

(B) To the applicable EPA Regional Office and appropriate State and/or local air pollution control agency, the hardcopy information required by paragraphs (b)(2)(i), (iii), and (iv).

(2) *Recertifications.* (i) Within 45 days after completing all recertification tests, submit to the Administrator the electronic information required by paragraph (b)(1) 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.

(ii) Within 45 days after completing all recertification tests, submit the hardcopy information required by paragraph (b)(2) to the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency. The applicable EPA Regional Office or appropriate State or local air pollution control agency may waive the requirement for submission to it of a hardcopy recertification. The applicable EPA Regional Office or the appropriate State or local air pollution control agency may also discontinue the waiver and reinstate the requirement of this paragraph to provide a hardcopy report of the recertification test data and results.

(iii) Notwithstanding the requirements of paragraphs (a)(2)(i) and (a)(2)(ii) of this section, for an event for which the Administrator determines that only diagnostic tests (see § 75.20(b)) are required, no hardcopy submittal is required; however, the results of all diagnostic test(s) shall be submitted in the electronic quarterly report required under § 75.64. For DAHS (missing data and formula) verifications, neither a hardcopy nor an electronic submittal of any kind is required; the owner or operator shall keep these test results on-site in a format suitable for inspection.

(b) *Contents.* Each application for initial certification or recertification shall contain the following information, as applicable:

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

(ii) The results of the test(s) required by § 75.20, including the type of test conducted, testing date, information required by § 75.56 or § 75.59, as applicable, and the results of any failed tests that affect data validation.

(2) *Hardcopy.* (i) Any changed portions of the hardcopy monitoring plan information required under

§§ 75.53(c) and (d), or §§ 75.53(e) and (f), as applicable. Electronic submittal of all monitoring plan information, including the hardcopy portions, is permissible, provided that a paper copy can be furnished upon request.

(ii) The results of the test(s) required by § 75.20, including the type of test conducted, testing date, information required by § 75.59(a)(9), and the results of any failed tests that affect data validation.

(iii) Certification or recertification application form (EPA form 7610–14).

(iv) Designated representative signature.

(c) *Format.* The electronic portion of each certification or recertification application shall be submitted in a format to be specified by the Administrator. The hardcopy test results shall be submitted in a format suitable for review and shall include the information in § 75.59(a)(9).

47. Section 75.64 is revised to 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 later of: the last (partial) calendar quarter of 1993 (where the calendar quarter data begins at November 15, 1993); or 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), whichever quarter is earlier. The initial quarterly report shall contain hourly data beginning with the hour of provisional certification or the hour corresponding to the relevant certification deadline, whichever is earlier. For an affected unit subject to § 75.4(d) that is shutdown on the relevant compliance date in § 75.4(a), the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences commercial operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced commercial operation of the unit). For any provisionally-certified monitoring system, § 75.20(a)(3) shall apply for initial certifications, and § 75.20(b)(5) shall apply for recertifications. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the date of report generation for the information provided in paragraphs (a)(2) through (a)(11) of this section, and shall also include for each affected unit (or group of units using a common stack):

(1) Facility information:

(i) Identification, including:

(A) Facility/ORISPL number;

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

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

(ii) Location, including:

(A) Plant name and facility ID;

(B) EPA AIRS facility system ID;

(C) State facility ID;

(D) Source category/type;

(E) Primary SIC code;

(F) State postal abbreviation;

(G) County code; and

(H) Latitude and longitude.

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

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

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

(iii) Opacity data listed in § 75.54(f) or § 75.57(f), and in § 75.59(a)(8);

(iv) For units with SO_2 or NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in § 75.55(b)(3) or § 75.58(b)(3);

(v) The information recorded under § 75.56(a)(7) for the period prior to April 1, 2000;

(vi) Information required by § 75.54(g) or § 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;

(vii) Hardcopy monitoring plan information required by § 75.53 and hardcopy test data and results required by § 75.56 or § 75.59;

(viii) Records of flow monitor and moisture monitoring system polynomial equations, coefficients or ''K'' factors required by § 75.56(a)(5)(vii), § 75.56(a)(5)(ix), § 75.59(a)(5)(vi) or § 75.59(a)(5)(vii);

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

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

(xi) Stratification test results required as part of the RATA supplementary records under §§ 75.56(a)(7) or 75.59(a)(7);

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

(xiv) Supplementary RATA information required under § 75.59(a)(7)(i) through § 75.59(a)(7)(v), except that: the data under § 75.59(a)(7)(ii)(A) through (T) and the data under § 75.59(a)(7)(iii)(A) through (M) shall, as applicable, be reported for flow RATAs in which angular compensation (measurement of pitch and/or yaw angles) is used and for flow RATAs in which a site-specific wall effects adjustment factor is determined by direct measurement; and the data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs in which a default wall effects adjustment factor is applied.

(3) Tons (rounded to the nearest tenth) of SO_2 emitted during the quarter and cumulative SO_2 emissions for the calendar year.

(4) Average NO_X emission rate (lb/mmBtu, rounded to the nearest hundredth prior to April 1, 2000 and to the nearest thousandth on and after April 1, 2000) during the quarter and cumulative NO_X emission rate for the calendar year.

(5) Tons of CO_2 emitted during quarter and cumulative CO_2 emissions for calendar year.

(6) Total heat input (mmBtu) for quarter and cumulative heat input for calendar year.

(7) Unit or stack or common pipe header operating hours for quarter and cumulative unit or stack or common pipe header operating hours for calendar year.

(8) If the affected unit is using a qualifying Phase I technology, then the quarterly report shall include the information required in paragraph (e) of this section.

(9) For low mass emissions units for which the owner or operator is using the optional low mass emissions methodology in § 75.19(c) to calculate NO_X mass emissions, the designated representative must also report tons (rounded to the nearest tenth) of NO_X emitted during the quarter and cumulative NO_X mass emissions for the calendar year.

(10) For low mass emissions units using the optional long term fuel flow methodology under § 75.19(c), for each quarter report the long term fuel flow for each fuel according to § 75.59.

(11) For units using the optional fuel flow to load procedure in section 2.1.7 of appendix D to this part, report both the fuel flow-to-load baseline data and

the results of the fuel flow-to-load test each quarter.

(b) The designated representative shall affirm that the component/system identification codes and formulas in the quarterly electronic reports, submitted to the Administrator pursuant to § 75.53, represent current operating conditions.

(c) *Compliance certification.* The designated representative shall submit a certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this part including the quality control and quality assurance procedures and specifications of this part and its appendices, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method. For a unit with add-on emission controls, the designated representative shall also include a certification, for all hours where data are substituted following the provisions of § 75.34(a)(1), that the add-on emission controls were operating within the range of parameters listed in the monitoring plan and that the substitute values recorded during the quarter do not systematically underestimate SO_2 or NO_X emissions, pursuant to § 75.34.

(d) *Electronic format.* Each quarterly report shall be submitted in a format to be specified by the Administrator, including both electronic submission of data and electronic or hardcopy submission of compliance certifications.

(e) *Phase I qualifying technology reports.* In addition to reporting the information in paragraphs (a), (b), and (c) of this section, the designated representative for an affected unit on which SO_2 emission controls have been installed and operated for the purpose of meeting qualifying Phase I technology requirements pursuant to § 72.42 of this chapter shall also submit reports documenting the measured percent SO_2 emissions removal to the Administrator on a quarterly basis, beginning the first quarter of 1997 and continuing through the fourth quarter of 1999. Each report shall include all measurements and calculations necessary to substantiate that the qualifying technology achieves the required percent reduction in SO_2 emissions.

(f) *Method of submission.* Beginning with the quarterly report for the first quarter of the year 2001, all quarterly reports shall be submitted to EPA by direct computer-to-computer electronic transfer via modem and EPA-provided software, unless otherwise approved by the Administrator.

(g) Any cover letter text accompanying a quarterly report shall either be submitted in hardcopy to the Agency or be provided in electronic format compatible with the other data required to be reported under this section.

48. Section 75.65 is revised to read as follows:

§ 75.65 Opacity reports.

The owner or operator or designated representative shall report excess emissions of opacity recorded under § 75.54(f) or § 75.57(f), as applicable, to the applicable State or local air pollution control agency.

49. Section 75.66 is amended by revising paragraph (a) and the first sentence of paragraph (e) introductory text; by redesignating paragraph (i) as paragraph (l) and revising it; and by adding paragraphs (i) through (k) to read as follows:

§ 75.66 Petitions to the Administrator.

(a) *General.* The designated representative for an affected unit subject to the requirements of this part may submit a petition to the Administrator requesting that the Administrator exercise his or her discretion to approve an alternative to any requirement prescribed in this part or incorporated by reference in this part. Any such petition shall be submitted in accordance with the requirements of this section. The designated representative shall comply with the signatory requirements of § 72.21 of this chapter for each submission.

* * * * *

(e) *Parametric monitoring procedure petitions.* The designated representative for an affected unit may submit a petition to the Administrator, where each petition shall contain the information specified in § 75.55(b) or § 75.58(b), as applicable, for the use of a parametric monitoring method. * * *

* * * * *

(i) *Emergency fuel petition.* The designated representative for an affected unit may submit a petition to the Administrator to use the emergency fuel provisions in section 2.1.4 of appendix E to this part. The designated representative shall include the following information in the petition:

(1) Identification of the affected plant and unit(s);

(2) A procedure for determining the NO_X emission rate for the unit when the emergency fuel is combusted; and

(3) A demonstration that the permit restricts use of the fuel to emergencies only.

(j) *Petition for alternative method of accounting for emissions prior to completion of certification tests.* The designated representative for an affected unit may submit a petition to the Administrator to use an alternative to the procedures in § 75.4(d)(3), (e)(3), (f)(3) or (g)(3) to account for emissions during the period between the compliance date for a unit and the completion of certification testing for that unit. The designated representative shall include:

(1) Identification of the affected unit(s);

(2) A detailed explanation of the alternative method to account for emissions of the following parameters, as applicable: SO_2 mass emissions (in lbs), NO_X emission rate (in lbs/mmBtu), CO_2 mass emissions (in lbs) and, if the unit is subject to the requirements of subpart H of this part, NO_X mass emissions (in lbs); and

(3) A demonstration that the proposed alternative does not underestimate emissions.

(k) *Petition for an alternative to the stabilization criteria for the cycle time test in section 6.4 of appendix A to this part.* The designated representative for an affected unit may submit a petition to the Administrator to use an alternative stabilization criteria for the cycle time test in section 6.4 of appendix A to this part, if the installed monitoring system does not record data in 1-minute or 3-minute intervals. The designated representative shall provide a description of the alternative criteria.

(l) *Any other petitions to the Administrator under this part.* Except for petitions addressed in paragraphs (b) through (k) of this section, any petition submitted under this paragraph shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(1) Identification of the affected plant and unit(s);

(2) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(3) A description and diagram of any equipment and procedures used in the proposed alternative, if applicable;

(4) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and is consistent with the purposes of this part and of section 412 of the Act and that any adverse effect of approving such alternative will be *de minimis*; and

(5) Any other relevant information that the Administrator may require.

Subpart H—NO_X Mass Emissions Provisions

50. Section 75.70 is amended by revising paragraphs (e), (f) introductory text and (f)(1)(iv), and by adding new paragraph (g)(6) to 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, and diluent monitors required under § 75.71. A NO_X concentration monitoring system for determining NO_X mass emissions in accordance with § 75.71 shall meet the same certification testing requirements, quality assurance requirements, and bias test requirements as are specified in this part for an SO_2 pollutant concentration monitor, except as otherwise provided in § 75.74(c). Units using excepted methods under § 75.19 shall meet the applicable quality assurance requirements of that section, and, except as otherwise provided in § 75.74(c), units using excepted monitoring methods under appendices D and E to this part shall meet the applicable quality assurance requirements of those appendices.

(f) *Missing data procedures.* Except as provided in § 75.34, paragraph (g) of this section, and § 75.74, the owner or operator shall provide substitute data from monitoring systems required under § 75.71 for each affected unit as follows:

(1) * * *

(iv) A valid, quality-assured hour of NO_X concentration data (in ppm) has not been measured and recorded by a certified NO_X concentration monitoring system, or by an approved alternative monitoring method under subpart E of this part, where the owner or operator chooses to use a NO_X concentration monitoring system with a volumetric flow monitor, and without a diluent monitor to calculate NO_X mass emissions. The initial missing data procedures for determining monitor data availability and the standard missing data procedures for a NO_X concentration monitoring system shall be the same as the procedures specified for a NO_X-diluent continuous emission monitoring system under §§ 75.31, 75.32 and 75.33.

* * * * *

(g) * * *

(6) For any unit using continuous emissions monitors, the procedures in § 75.20(b)(3).

* * * * *

51. Section 75.71 is amended by revising paragraphs (b) and (d)(2) to 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.

* * * * *

(b) *Moisture correction.* (1) If a correction for the stack gas moisture content is needed to properly calculate the NO_X emission rate in lb/mmBtu (i.e., if the NO_X pollutant concentration monitor in a NO_X-diluent monitoring system measures on a different moisture basis from the diluent monitor), the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with § 75.12(b).

(2) If a correction for the stack gas moisture content is needed to properly calculate NO_X mass emissions in tons, in the case where a NO_X concentration monitoring system which measures on a dry basis is used with a flow rate monitor to determine NO_X mass emissions, the owner or operator of an affected unit shall account for the moisture content of the flue gas on a continuous basis in accordance with § 75.11(b) except that the term ‘‘SO_2’’ shall be replaced by the term ‘‘NO_X.’’

(3) If a correction for the stack gas moisture content is needed to properly calculate NO_X mass emissions, in the case where a diluent monitor that measures on a dry basis is used with a flow rate monitor to determine heat input, which is then multiplied by the NO_X emission rate, the owner or operator shall install, operate, maintain and quality assure a continuous moisture monitoring system, as described in § 75.11(b).

* * * * *

(d) * * *

(2) Use the procedures in appendix D to this part for determining hourly heat input and the procedure specified in appendix E to this part for estimating hourly NO_X emission rate. However, 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. In addition, if after certification of an excepted monitoring system under appendix E to this part, the operation of a unit that reports emissions on an annual basis under § 75.74(a) of this part exceeds a capacity factor of 20.0 percent in any calendar year or exceeds an annual capacity factor of 10.0 percent averaged over three years, or the operation of a unit that reports emissions on an ozone season basis under § 75.74(b) of this part exceeds a capacity factor of 20.0 percent in any ozone season or exceeds an ozone season capacity factor of 10.0 percent averaged over three years, the owner or operator shall meet the requirements of paragraph (c) of this section or, if applicable, paragraph (e) of this section by no later than December 31 of the following calendar year.

* * * * *

52. Text is added to reserved section 75.73 to read as follows:

§ 75.73 Recordkeeping and reporting.

(a) *General recordkeeping provisions.* The owner or operator of any affected unit shall maintain for each affected unit and each non-affected unit under § 75.72(b)(2)(ii) a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Except for the certification data required in § 75.57(a)(4) and the initial submission of the monitoring plan required in § 75.57(a)(5), the data shall be collected beginning with the earlier of the date of provisional certification or the deadline in § 75.70. The certification data required in § 75.57(a)(4) shall be collected beginning with the date of the first certification test performed. The file shall contain the following information:

(1) The information required in §§ 75.57(a)(2), (a)(4), (a)(5), (a)(6), (b), (c)(2), (d), (g), and (h).

(2) The information required in §§ 75.58(b)(2) or (b)(3) (for units with add-on NO_X emission controls), as applicable, (d) (as applicable for units using Appendix E to this part), and (f) (as applicable for units using the low mass emissions unit provisions of § 75.19).

(3) For each hour when the unit is operating, NO_X mass emissions, calculated in accordance with section 8.1 of appendix F to this part.

(4) During the second and third calendar quarters, cumulative ozone season heat input and cumulative ozone season operating hours.

(5) Heat input and NO_X methodologies for the hour.

(6) *Specific heat input record provisions for gas-fired or oil-fired units using the procedures in appendix D to this part.* In lieu of the information required in § 75.57(c)(2), the owner or operator shall record the following information in this paragraph for each

affected gas-fired or oil-fired unit and each non-affected gas- or oil-fired unit under § 75.72(b)(2)(ii) for which the owner or operator is using the procedures in appendix D to this part for estimating heat input:

(i) For each hour when the unit is combusting oil:

(A) Date and hour;

(B) Hourly average mass flow rate of oil, while the unit combusts oil (in lb/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(C) Method of oil sampling (flow proportional, continuous drip, as delivered, manual from storage tank, or daily manual);

(D) For units using volumetric flowmeters, volumetric flow rate of oil combusted each hour (in gal/hr, lb/hr, m^3/hr, or bbl/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(E) For units using volumetric oil flowmeters, density of oil (flag value if derived from missing data procedures);

(F) Gross calorific value of oil used to determine heat input (in Btu/lb);

(G) Hourly heat input rate during combustion of oil, according to procedures in appendix F to this part (in mmBtu/hr, to the nearest tenth);

(H) Fuel usage time for combustion of oil during the hour (rounded up to the nearest 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) (flag to indicate multiple/single fuel types combusted); and

(I) Monitoring system identification code.

(ii) For gas-fired units or oil-fired units, using the procedures in appendix D to this part with an assumed density or for as-delivered fuel sampled from each delivery:

(A) Measured gross calorific value and, if measuring with volumetric oil flowmeters, density from each fuel sample; and

(B) Assumed gross calorific value and, if measuring with volumetric oil flowmeters, density used to calculate heat input rate.

(iii) For each hour when the unit is combusting gaseous fuel:

(A) Date and hour;

(B) Hourly heat input rate from gaseous fuel, according to procedures in appendix F to this part (in mmBtu/hr, rounded to the nearest tenth);

(C) Hourly flow rate of gaseous fuel, while the unit combusts gas (in 100 scfh) (flag value if derived from missing data procedures);

(D) Gross calorific value of gaseous fuel used to determine heat input rate (in Btu/100 scf) (flag value if derived from missing data procedures);

(E) Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest 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) (flag to indicate multiple/single fuel types combusted); and

(F) Monitoring system identification code.

(iv) For each oil sample or sample of diesel fuel:

(A) Date of sampling;

(B) Gross calorific value (in Btu/lb) (flag value if derived from missing data procedures); and

(C) Density or specific gravity, if required to convert volume to mass (flag value if derived from missing data procedures).

(v) For each sample of gaseous fuel:

(A) Date of sampling; and

(B) Gross calorific value (in Btu/100 scf) (flag value if derived from missing data procedures).

(vi) For each oil sample or sample of gaseous fuel:

(A) Type of oil or gas; and

(B) Percent carbon or F-factor of fuel.

(7) *Specific NO_X record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in § 75.19.* In lieu of recording the information in §§ 75.57(b), (c)(2), (d), and (g), the owner or operator shall record, for each hour when the unit is operating for any portion of the hour, the following information for each affected low mass emissions unit for which the owner or operator is using the low mass emissions excepted methodology in § 75.19(c):

(i) Date and hour;

(ii) If one type of fuel is combusted in the hour, fuel type (pipeline natural gas, natural gas, residual oil, or diesel fuel) or, if more than one type of fuel is combusted in the hour, the fuel type which results in the highest emission factors for NO_X;

(iii) Average hourly NO_X emission rate (in lb/mmBtu, rounded to the nearest thousandth); and

(iv) Hourly NO_X mass emissions (in lbs, rounded to the nearest tenth).

(b) *Certification, quality assurance and quality control record provisions.* The owner or operator of any affected unit shall record the applicable information in § 75.59 for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii).

(c) *Monitoring plan recordkeeping provisions*—(1) *General provisions.* The owner or operator of an affected unit shall prepare and maintain a monitoring plan for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii). Except as provided in paragraph (d) or (f) of this section, a monitoring plan shall contain sufficient information on the continuous emission monitoring systems, excepted methodology under § 75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these systems to demonstrate that all the unit's NO_X emissions are monitored and reported.

(2) Whenever the owner or operator makes a replacement, modification, or change in the certified continuous emission monitoring system, excepted methodology under § 75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

(3) *Contents of the monitoring plan for units not subject to an Acid Rain emissions limitation.* Each monitoring plan shall contain the information in § 75.53(e)(1) in electronic format and the information in § 75.53(e)(2) in hardcopy format. In addition, to the extent applicable, each monitoring plan shall contain the information in §§ 75.53(f)(1)(i), (f)(2)(i), (f)(4), and (f)(5)(i) for units using the low mass emitter methodology in electronic format and the information in §§ 75.53(f)(1)(ii), (f)(2)(ii), and (f)(5)(ii) in hardcopy format. 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, and whether year-round reporting for the unit is required by a state or local agency.

(d) *General reporting provisions.* (1) The designated representative for an affected unit shall comply with all reporting requirements in this section and with any additional requirements set forth in an applicable State or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) The designated representative for an affected unit shall submit the following for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii):

(i) Initial certification and recertification applications in accordance with § 75.70(d);

(ii) Monitoring plans in accordance with paragraph (e) of this section; and

(iii) Quarterly reports in accordance with paragraph (f) of this section.

(3) *Other petitions and communications.* The designated representative for an affected unit shall submit petitions, correspondence, application forms, and petition-related test results in accordance with the provisions in § 75.70(h).

(4) *Quality assurance RATA reports.* If requested by the permitting authority, the designated representative of an affected unit shall submit the quality assurance RATA report for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii) by the later of 45 days after completing a quality assurance RATA according to section 2.3 of appendix B to this part or 15 days of receiving the request. The designated representative shall report the hardcopy information required by § 75.59(a)(9) to the permitting authority.

(5) *Notifications.* The designated representative for an affected unit shall submit written notice to the permitting authority according to the provisions in § 75.61 for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii).

(e) *Monitoring plan reporting.*—(1) *Electronic submission.* 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 (e)(2) of this section) for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii) as follows:

(i) To the permitting authority, no later than 45 days prior to the initial certification test and at the time of recertification application submission; and

(ii) To the Administrator, no later than 45 days prior to the initial certification test, at the time of submission of a recertification application, and in each electronic quarterly report.

(2) *Hardcopy submission.* The designated representative of an affected unit shall submit all of the hardcopy information required under § 75.53, for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii), to the permitting authority prior to initial certification. Thereafter, the designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information as follows: no later than 45 days prior to the initial certification test; with any recertification application, if a hardcopy monitoring plan change is associated with the recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to § 75.53(b).

(f) *Quarterly reports.*—(1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the date of report generation, for the information provided in paragraphs (f)(1)(ii) through (1)(vi) of this section, and shall also include for each affected unit or group of units monitored at a common stack:

(i) Facility information:

(A) Identification, including:

(*1*) Facility/ORISPL number;

(*2*) Calendar quarter and year data contained in the report; and

(*3*) Electronic data reporting format version used for the report.

(B) Location of facility, including:

(*1*) Plant name and facility identification code;

(*2*) EPA AIRS facility system identification code;

(*3*) State facility identification code;

(*4*) Source category/type;

(*5*) Primary SIC code;

(*6*) State postal abbreviation;

(*7*) FIPS county code; and

(*8*) Latitude and longitude.

(ii) The information and hourly data required in paragraph (a) of this section, except for:

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

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

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

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

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

(F) Records of flow polynomial equations and numerical values required by § 75.59(a)(5)(vi);

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

(H) Information required by § 75.59(b)(2) concerning transmitter or transducer accuracy tests;

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

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

(K) Supplementary RATA information required under § 75.59(a)(7)(i) through § 75.59(a)(7)(v), except that: the data under § 75.59(a)(7)(ii)(A) through (T) and the data under § 75.59(a)(7)(iii)(A) through (M) shall, as applicable, be reported for flow RATAs in which angular compensation (measurement of pitch and/or yaw angles) is used and for flow RATAs in which a site-specific wall effects adjustment factor is determined by direct measurement; and the data under § 75.59(a)(7)(ii)(T) shall be reported for all flow RATAs in which a default wall effects adjustment factor is applied.

(iii) Average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) during the quarter and cumulative NO_X emission rate for the calendar year.

(iv) Tons of NO_X emitted during quarter, cumulative tons of NO_X emitted during the year, and, during the second and third calendar quarters, cumulative tons of NO_X emitted during the ozone season.

(v) During the second and third calendar quarters, cumulative heat input for the ozone season.

(vi) Unit or stack or common pipe header operating hours for quarter, cumulative unit, stack or common pipe header operating hours for calendar year, and, during the second and third calendar quarters, cumulative operating hours during the ozone season.

(2) The designated representative shall certify that the component and system identification codes and formulas in the quarterly electronic reports submitted to the Administrator pursuant to paragraph (e) of this section represent current operating conditions.

(3) *Compliance certification.* The designated representative shall submit and sign a compliance certification in

support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this part, including the quality assurance procedures and specifications; and

(ii) With regard to a unit with add-on emission controls and for all hours where data are substituted in accordance with § 75.34(a)(1), the add-on emission controls were operating within the range of parameters listed in the monitoring plan and the substitute values do not systematically underestimate NO_X emissions.

(4) The designated representative shall comply with all of the quarterly reporting requirements in §§ 75.64(d), (f), and (g).

53. Section 75.74 is amended by:

a. Revising paragraphs (b)(2), (c)(1) and (c)(2);

b. Redesignating paragraphs (c)(3), (c)(4), (c)(5), (c)(6), (c)(7), (c)(8), (c)(9) and (c)(10), as paragraphs (c)(4), (c)(5), (c)(6), (c)(7), (c)(8), (c)(9), (c)(10) and (c)(11), respectively;

c. Adding a new paragraph (c)(3); and

d. Revising newly redesignated paragraphs (c)(4), (c)(5), (c)(6) and (c)(7), to read as follows:

§ 75.74 Annual and ozone season monitoring and reporting requirements.

* * * * *

(b) * * *

(2) Meet the requirements of this subpart during the ozone season, except as specified in paragraph (c) of this section.

(c) * * *

(1) The owner or operator of a unit that uses continuous emissions monitoring systems or a fuel flowmeter to meet any of the requirements of this subpart shall quality assure the hourly ozone season emission data required by this subpart. To achieve this, the owner or operator shall operate, maintain and calibrate each required CEMS and shall perform diagnostic testing and quality assurance testing of each required CEMS or fuel flowmeter according to the applicable provisions of paragraphs (c)(2) through (c)(5) of this section. Except where otherwise noted, the provisions of paragraphs (c)(2) and (c)(3) of this section apply instead of the quality assurance provisions in sections 2.1 through 2.3 of appendix B to this part, and shall be used in lieu of those appendix B provisions.

(2) *Quality assurance requirements prior to the ozone season.* The provisions of this paragraph apply to each ozone season. In the time period prior to the start of the current ozone season (i.e., in the period extending from October 1 of the previous calendar year through April 30 of the current calendar year), the owner or operator shall, at a minimum, perform the following diagnostic testing and quality assurance assessments, and shall maintain the following records, to ensure that the hourly emission data recorded at the beginning of the current ozone season are suitable for reporting as quality-assured data:

(i) For each required gas monitor (i.e., for each NO_X pollutant concentration monitor and each diluent gas (CO_2 or O_2) monitor, including CO_2 and O_2 monitors used exclusively for heat input determination and O_2 monitors used for moisture determination), a linearity check shall be performed and passed.

(A) Conduct each linearity check in accordance with the general procedures in section 6.2 of appendix A to this part, except that the data validation procedures in sections 6.2(a) through (f) of appendix A do not apply.

(B) Each linearity check shall be done "hands-off," as described in section 2.2.3(c) of appendix B to this part.

(C) In the time period extending from the date and hour in which the linearity check is passed through April 30 of the current calendar year, the owner or operator shall operate and maintain the CEMS and shall perform daily calibration error tests of the CEMS in accordance with section 2.1 of appendix B to this part. When a calibration error test is failed, as described in section 2.1.4 of appendix B to this part, corrective actions shall be taken. The additional calibration error test provisions of section 2.1.3 of appendix B to this part shall be followed. Records of the required daily calibration error tests shall be kept in a format suitable for inspection on a year-round basis.

(D) *Exceptions.* (*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 less than 336 hours in the previous ozone season, the owner or operator may have a grace period of up to 168 hours to perform a linearity check. In addition, if the unit or stack operates for 168 hours or less in the current ozone season the owner or operator is exempt from the linearity check requirement for that ozone season and the owner or operator may 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 168 hours in the current ozone season, the owner or operator of the unit shall report substitute data using the missing data procedures under paragraph (c)(7) of this section starting with the 169th unit or stack operating hour of the ozone season and continuing until the successful completion of a linearity check.

(*2*) If a monitor does not qualify for an exception under paragraph (c)(2)(i)(D)(1) and if a required linearity check has not been completed prior to the start of the current ozone season, follow the applicable procedures in paragraph (c)(3)(vi) of this section.

(ii) For each required CEMS (i.e., for each NO_X concentration monitoring system, each NO_X-diluent monitoring system, each flow rate monitoring system, each moisture monitoring system and each diluent gas CEMS used exclusively for heat input determination), a relative accuracy test audit (RATA) shall be performed and passed.

(A) Conduct each RATA in accordance with the applicable procedures in sections 6.5 through 6.5.10 of appendix A to this part, except that the data validation procedures in sections 6.5(f)(1) through (f)(6) do not apply, and, for flow rate monitoring systems, the required RATA load level(s) shall be as specified in this paragraph.

(B) Each RATA shall be done "hands-off," as described in section 2.3.2 (c) of appendix B to this part. The provisions in section 2.3.1.4 of appendix B to this part, pertaining to the number of allowable RATA attempts, shall apply.

(C) For flow rate monitoring systems installed on peaking units or bypass stacks, a single-load RATA is required. For all other flow rate monitoring systems, a 2-load RATA is required at the two most frequently-used load levels (as defined under section 6.5.2.1 of appendix A to this part), with the following exceptions. A 3-load flow RATA is required at least once in every period of five consecutive calendar years. A 3-load RATA 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.

(D) A bias test of each required NO_X concentration monitoring system, each NO_X-diluent monitoring system and each flow rate monitoring system shall be performed in accordance with section 7.6 of appendix A to this part. If the bias test is failed, a bias adjustment factor (BAF) shall be calculated for the monitoring system, as described in section 7.6.5 of appendix A to this part and shall be applied to the subsequent data recorded by the CEMS.

(E) In the time period extending from the hour of completion of the required RATA through April 30 of the current calendar year, the owner or operator shall operate and maintain the CEMS by performing, at a minimum, the following activities:

(*1*) The owner or operator shall perform daily calibration error tests and (if applicable) daily flow monitor interference checks, according to section 2.1 of appendix B to this part. When a daily calibration error test or interference check is failed, as described in section 2.1.4 of appendix B to this part, corrective actions shall be taken. The additional calibration error test provisions in section 2.1.3 of appendix B to this part shall be followed. Records of the required daily calibration error tests and interference checks shall be kept in a format suitable for inspection on a year-round basis.

(*2*) If the owner or operator makes a replacement, modification, or change in a certified monitoring system that significantly affects the ability of the system to accurately measure or record NO_X mass emissions or heat input or to meet the requirements of § 75.21 or appendix B to this part, the owner or operator shall recertify the monitoring system according to § 75.20(b).

(F) If the results of a RATA performed according to the provisions of this paragraph indicate that the CEMS qualifies for an annual RATA frequency (see Figure 2 in appendix B to this part), the RATA may be used to quality assure data for the entire current ozone season.

(G) If the results of a RATA performed according to the provisions of this paragraph indicate that the CEMS qualifies for a semiannual RATA frequency rather than an annual frequency, provided that the RATA was completed on or after January 1 of the current calendar year, the RATA may be used to quality assure data for the entire current ozone season. However, if the RATA was performed in the fourth calendar quarter of the previous year, the RATA may only be used to quality assure data for a part of the current ozone season, from May 1 through June 30. An additional RATA is then required by June 30 of the current calendar year to quality assure the remainder of the data (from June 30 through September 30) for the current ozone season. If such an additional RATA is required but is not completed by June 30 of the current calendar year, data from the CEMS shall be considered invalid as of the first unit or stack operating hour subsequent to June 30 of the current calendar year and shall remain invalid until the required RATA is performed and passed.

(H) *Exceptions.* (*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 less than 336 hours in the previous ozone season, the owner or operator may have a grace period of up to 720 hours to perform a RATA. If the unit or stack operates for 720 hours or less in the current ozone season, the owner or operator of the unit is exempt from the requirement to perform a RATA for that ozone season and the owner or operator may 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 720 hours in the current ozone season, the owner or operator of the unit or stack shall report substitute data using the missing data procedures under paragraph (c)(7) of this section, starting with the 721st unit operating hour and continuing until the successful completion of the RATA.

(*2*) If a monitor does not qualify for a grace period under paragraph (c)(2)(ii)(H)(*1*) of this section and if a required RATA has not been completed prior to the start of the current ozone season, follow the applicable procedures in paragraph (c)(3)(vi) of this section.

(3) *Quality assurance requirements within the ozone season.* The provisions of this paragraph apply to each ozone season. The owner or operator shall, at a minimum, perform the following quality assurance testing during the ozone season, i.e. in the time period extending from May 1 through September 30 of each calendar year:

(i) Daily calibration error tests and (if applicable) interference checks of each CEMS required by this subpart shall be performed in accordance with sections 2.1.1 and 2.1.2 of appendix B to this part. The applicable provisions in sections 2.1.3, 2.1.4 and 2.1.5 of appendix B to this part, pertaining, respectively, to additional calibration error tests and calibration adjustments, data validation, and quality assurance of data with respect to daily assessments, shall also apply.

(ii) For each gas monitor required by this subpart, linearity checks shall be performed in the second and third calendar quarters, in accordance with section 2.2.1 of appendix B to this part (see also paragraph (c)(3)(vii) of this section). For the second calendar quarter of the year, only unit or stack operating hours in the months of May and June shall be included when determining whether the second calendar quarter is a ''QA operating quarter'' (as defined in § 72.2 of this chapter). Data validation for these linearity checks shall be done in accordance with sections 2.2.3(a) through (e) of appendix B to this part. The grace period provision in section 2.2.4 of appendix B to this part does not apply to these linearity checks. If the required linearity check has not been completed by the end of the calendar quarter, unless the conditional data validation provisions of § 75.20(b)(3) are applied, data from the CEMS are considered to be invalid, beginning with the first unit or stack operating hour after the end of the quarter and shall remain invalid until a linearity check of the CEMS is performed and passed.

(iii) For each flow monitoring system required by this subpart, 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 declare the flow monitor out-of-control as of the first unit or stack operating hour following the second calendar quarter and shall either implement Option 1 in section 2.2.5.1 of appendix B to this part or Option 2 in section 2.2.5.2 of appendix B to this part. If the flow-to-load ratio test for the third calendar quarter is failed, data from the flow monitor shall be considered invalid at the beginning of the next ozone season unless, prior to May 1 of the next calendar year, the owner or operator has either successfully implemented Option 1 in section 2.2.5.1 of appendix B to this part or Option 2 in section 2.2.5.2 of appendix B to this part, or unless a flow RATA has been performed and passed in accordance with paragraph (c)(2)(ii) of this section.

(iv) For each differential pressure-type flow monitor used to meet the requirements of this subpart, quarterly leak checks are required in the second and third calendar quarters, in accordance with section 2.2.2 of appendix B to this part. For the second calendar quarter of the year, only unit or stack operating hours in the months of May and June shall be included when determining whether the second calendar quarter is a QA operating quarter (as defined in § 72.2 of this chapter). Data validation for quarterly flow monitor leak checks shall be done in accordance with section 2.2.3(g) of appendix B to this part. If the leak check for the third calendar quarter is failed and a subsequent leak check is not passed by the end of the ozone season, then data from the flow monitor shall be considered invalid at the beginning of the next ozone season unless a leak check is passed prior to May 1 of the next calendar year.

(v) A fuel flow-to-load ratio test in section 2.1.7 of appendix D to this part shall be performed in the second and third calendar quarters if, for a unit using a fuel flowmeter to determine heat input under this subpart, the owner or operator has elected to use the fuel flow-to-load ratio test to extend the deadline for the next fuel flowmeter accuracy test. If a fuel flow-to-load ratio test is failed, follow the applicable procedures and data validation provisions in section 2.1.7.4 of appendix D to this part. If the fuel flow-to-load ratio test for the third calendar quarter is failed, data from the fuel flowmeter shall be considered invalid at the beginning of the next ozone season unless the requirements of section 2.1.7.4 of appendix D to this part have been fully met prior to May 1 of the next calendar year.

(vi) If, at the start of the current ozone season (i.e., as of May 1 of the current calendar year), the linearity check or RATA required under paragraph (c)(2)(i) or (c)(2)(ii) of this section has not been performed for a particular monitor or monitoring system, and if, during the previous ozone season, the unit or stack on which the monitoring system is installed operated for 336 hours or more the owner or operator shall invalidate all data from the CEMS until either:

(A) The required linearity check or RATA of the CEMS has been performed and passed; or

(B) A ''probationary calibration error test'' of the CEMS is passed in accordance with § 75.20(b)(3). Note that a calibration error test passed on April 30 may be used as the probationary calibration error test, to ensure that emission data recorded by the CEMS at the beginning of the ozone season will have a conditionally valid status. Once the probationary calibration error test has been passed, the owner or operator shall perform the required linearity check or RATA in accordance with the conditional data validation provisions and within the associated timelines in § 75.20(b)(3), with the term ''diagnostic'' applying instead of the term ''recertification''. However, in lieu of the provisions in § 75.20(b)(3)(ix), the owner or operator shall follow the applicable provisions in paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(vii) A RATA which is performed and passed during the second or third quarter of the current calendar year may be used to quality assure data in the next ozone season, provided that:

(A) The results of the RATA indicate that the CEMS qualifies for an annual RATA frequency (see Figure 2 in appendix B to this part); and

(B) The CEMS is continuously operated and maintained, and daily calibration error tests and (if applicable) interference checks of the CEMS are performed in the time period extending from the end of the current ozone season (October 1 of the current calendar year) through April 30 of the next calendar year; and

(C) For a gas monitoring system, the linearity check requirement of paragraph (c)(2)(i) of this section is met prior to May 1 of the next calendar year.

(D) If conditions in paragraphs (c)(3)(vii)(A), (B) and, if applicable, (c)(3)(vii)(C) of this section are met, then a RATA completed and passed in the second or third calendar quarter of the current year may be used to quality assure data for the next ozone season, as follows:

(*1*) If the RATA is completed and passed in the second calendar quarter of the current year, the RATA may be used to quality assure data from the CEMS through June 30 of the next calendar year.

(*2*) If the RATA is completed and passed in the third calendar quarter of the current year, the RATA may be used to quality assure data from the CEMS through September 30 of the next calendar year.

(viii) If a linearity check performed to meet the requirement of paragraph (c)(2)(i) of this section is completed and passed in the second calendar quarter of the current year, provided that the date and hour of completion of the test is within the first 168 unit or stack operating hours of the current ozone season, the linearity check may be used to satisfy both the requirement of paragraph (c)(2)(i) of this section and to meet the second quarter linearity check requirement of paragraph (c)(3)(ii) of this section.

(ix) If, for any required CEMS, diagnostic linearity checks or RATAs other than those required by this section are performed during the ozone season, use the applicable data validation procedures in section 2.2.3 (for linearity checks) or 2.3.2 (for RATAs) of appendix B to this part.

(x) If any required CEMS is recertified within the ozone season, use the data validation provisions in § 75.20(b)(3) and paragraphs (c)(3)(xi) and (c)(3)(xii) of this section.

(xi) If, at the end of the second quarter of any calendar year, a required quality assurance, diagnostic or recertification test of a monitoring system has not been completed, and if data contained in the quarterly report are conditionally valid pending the results of test(s) to be completed in a subsequent quarter, the owner or operator shall indicate this by means of a suitable conditionally valid data flag in the electronic quarterly report for the second calendar quarter. The owner or operator shall resubmit the report for the second quarter if the required quality assurance, diagnostic or recertification test is subsequently failed. In the resubmitted report, the owner or operator shall use the appropriate missing data routine in § 75.31 or § 75.33 to replace with substitute data each hour of conditionally valid data that was invalidated by the failed quality assurance, diagnostic or recertification test. Alternatively, if any required quality assurance, diagnostic or recertification test is not completed by the end of the second calendar quarter but is completed no later than 30 days after the end of that quarter (i.e., prior to the deadline for submitting the quarterly report under § 75.73), the test data and results may be submitted with the second quarter report even though the test date(s) are from the third calendar quarter. In such instances, if the quality assurance, diagnostic or recertification test(s) are passed in accordance with the provisions of § 75.20(b)(3), conditionally valid data may be reported as quality-assured, in lieu of reporting a conditional data flag. If the tests are failed and if conditionally valid data are replaced, as appropriate, with substitute data, then neither the reporting of a conditional data flag nor resubmission is required.

(xii) If, at the end of the third quarter of any calendar year, a required quality assurance, diagnostic or recertification test of a monitoring system has not been completed, and if data contained in the quarterly report are conditionally valid pending the results of test(s) to be completed, the owner or operator shall do one of the following:

(A) If the results of the required tests are not available within 30 days of the end of the third calendar quarter and cannot be submitted with the quarterly report for the third calendar quarter, then the test results are considered to be missing and the owner or operator shall use the appropriate missing data routine in § 75.31 or § 75.33 to replace with substitute data each hour of conditionally valid data in the third quarter report. In addition, if the data in the second quarterly report were flagged as conditionally valid at the end of the quarter, pending the results of the same missing tests, the owner or operator shall resubmit the report for the second quarter and shall use the appropriate missing data routine in § 75.31 or § 75.33 to replace with substitute data each hour of conditionally valid data associated with the missing quality assurance, diagnostic or recertification tests; or

(B) If the required quality assurance, diagnostic or recertification tests are completed no later than 30 days after the end of the third calendar quarter, the test data and results may be submitted with the third quarter report even though the test date(s) are from the fourth calendar quarter. In this instance, if the required tests are passed in accordance with the provisions of § 75.20(b)(3), all conditionally valid data associated with the tests shall be reported as quality assured. If the tests are failed, the owner or operator shall use the appropriate missing data routine in § 75.31 or § 75.33 to replace with substitute data each hour of conditionally valid data associated with the failed test(s). In addition, if the data in the second quarterly report were flagged as conditionally valid at the end of the quarter, pending the results of the same failed test(s), the owner or operator shall resubmit the report for the second quarter and shall use the appropriate missing data routine in § 75.31 or § 75.33 to replace with substitute data each hour of conditionally valid data associated with the failed test(s).

(4) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input is required to maintain fuel flowmeters only during the ozone season, except that for purposes of determining the deadline for the next periodic quality assurance test on the fuel flowmeter, the owner or operator shall include all fuel flowmeter QA operating quarters (as defined in § 72.2) for the entire calendar year, not just fuel flowmeter QA operating quarters in the ozone season. For each calendar year, the owner or operator shall record, for each fuel flowmeter, the number of fuel flowmeter QA operating quarters.

(5) The owner or operator of a unit using the procedures in appendix D of this part to determine heat input is only required to sample fuel for the purposes of determining density and GCV during the ozone season, except that:

(i) The owner or operator of a unit that performs sampling from the fuel storage tank upon delivery must sample the tank between the date and hour of the most recent delivery before the first date and hour that the unit operates in the ozone season and the first date and hour that the unit operates in the ozone season.

(ii) The owner or operator of a unit that performs sampling upon delivery from the delivery vehicle must ensure that all shipments received during the calendar year are sampled.

(iii) The owner or operator of a unit that performs sampling on each day the unit combusts fuel or that performs fuel sampling continuously must sample the fuel starting on the first day the unit operates during the ozone season. The owner or operator then shall use that sampled value for all hours of combustion during the first day of unit operation, continuing until the date and hour of the next sample.

(6) The owner or operator shall, in accordance with § 75.73, record and report the hourly data required by this subpart and shall record and report the results of all required quality assurance tests, as follows:

(i) All hourly emission data for the period of time from May 1 through September 30 of each calendar year shall be recorded and reported. For missing data purposes, only the data recorded in the time period from May 1 through September 30 shall be considered quality-assured;

(ii) The results of all daily calibration error tests and flow monitor interference checks performed in the time period from May 1 through September 30 shall be recorded and reported;

(iii) For the time periods described in paragraphs (c)(2)(i)(C) and (c)(2)(ii)(E) of this section, hourly emission data and the results of all daily calibration error tests and flow monitor interference checks shall be recorded. The results of all daily calibration error tests and flow monitor interference checks performed in the time period from April 1 through April 30 shall be reported. The owner or operator may also report the hourly emission data and unit operating data recorded in the time period from April 1 through April 30. However, only the emission data recorded in the time period from May 1 through September 30 shall be used for NO_X mass compliance determination;

(iv) The results of all required quality assurance tests (RATAs, linearity checks, flow-to-load ratio tests and leak checks) performed during the ozone season shall be reported in the appropriate ozone season quarterly report; and

(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.

(7) The owner or operator shall use only quality-assured data from within ozone seasons in the substitute data procedures under subpart D of this part and section 2.4.2 of appendix D to this part.

(i) The lookback periods (e.g., 2160 quality-assured monitor operating hours for a NO_X-diluent continuous emission monitoring system, a NO_X concentration monitoring system, or a flow monitoring system) used to calculate missing data must include only quality-assured data from periods within ozone seasons.

(ii) The missing data procedures of §§ 75.31 through 75.33 shall be used, with two exceptions. First, when the NO_X emission rate or NO_X concentration of the unit was consistently lower in the previous ozone season because the unit combusted a fuel that produces less NO_X than the fuel currently being combusted; and second, when the unit's add-on emission controls are not working properly, as shown by the parametric data recorded under paragraph (c)(8) of this section. In those two cases, 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 for the fuel currently being combusted. The length of time for which the owner or operator shall substitute these maximum potential values for each hour of missing NO_X operator shall substitute these maximum potential value for each hour of missing NO_X data, shall be as follows:

(A) For a unit that changed fuels, substitute the maximum potential values until the first hour when the unit combusts a fuel that produces the same or less NO_X than the fuel combusted in the previous ozone season; and

(B) For a unit with add-on emission controls that are not working properly, substitute the maximum potential values until the first hour in which the add-on emission controls are documented to be operating properly, according to paragraph (c)(8) of this section.

* * * * *

54. Appendix A to part 75 is amended by—

a. Revising sections 2 through 2.1.1.4;

b. Adding section 2.1.1.5;

c. Revising sections 2.1.2 through 2.1.2.4;

d. Adding section 2.1.2.5;

e. Revising section 2.1.3;

f. Adding sections 2.1.3.1 through 2.1.3.3;

g. Revising section 2.1.4;

h. Adding sections 2.1.4.1 through 2.1.6;

i. Removing and reserving section 2.2 and removing sections 2.2.1 through 2.2.2.2 to read as follows:

Appendix A to Part 75—Specifications and Test Procedures

* * * * *

2. Equipment Specifications

2.1 Instrument Span and Range

In implementing sections 2.1.1 through 2.1.6 of this appendix, set the measurement range for each parameter (SO_2, NO_X, CO_2, O_2, or flow rate) high enough to prevent full-scale exceedances from occurring, yet low enough to ensure good measurement accuracy and to maintain a high signal-to-noise ratio. To meet these objectives, select the range such that the readings obtained during typical unit operation are kept, to the extent practicable, between 20.0 and 80.0 percent of 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; 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 with SO_2 or NO_X emission controls, provided that the readings occur during periods of high control device efficiency.

2.1.1 SO_2 Pollutant Concentration Monitors

Determine, as indicated in this section 2, the span value(s) and range(s) for an SO_2 pollutant concentration monitor so that all potential and expected concentrations can be accurately measured and recorded. Note that if a unit exclusively combusts fuels that are very low sulfur fuels (as defined in § 72.2 of this chapter), the SO_2 monitor span requirements in § 75.11(e)(3)(iv) apply in lieu of the requirements of this section.

2.1.1.1 Maximum Potential Concentration

(a) Make an initial determination of the maximum potential concentration (MPC) of SO_2 by using Equation A–1a or A–1b. Base the MPC calculation on the maximum percent sulfur and the minimum gross calorific value (GCV) for the highest-sulfur fuel to be burned. The maximum sulfur content and minimum GCV shall be determined from all available fuel sampling and analysis data for that fuel from the previous 12 months (minimum), excluding clearly anomalous fuel sampling values. If the designated representative certifies that the highest-sulfur fuel is never burned alone in the unit during normal operation but is always blended or co-fired with other fuel(s), the MPC may be calculated using a best estimate of the highest sulfur content and lowest gross calorific value expected for the blend or fuel mixture and inserting these values into Equation A–1a or A–1b. Derive the best estimate of the highest percent sulfur and lowest GCV for a blend or fuel mixture from weighted-average values based upon the historical composition of the blend or mixture in the previous 12 (or more) months. If insufficient representative fuel sampling data are available to determine the maximum sulfur content and minimum GCV, use values from contract(s) for the fuel(s) that will be combusted by the unit in the MPC calculation.

(b) Alternatively, if a certified SO_2 CEMS is already installed, the owner or operator may make the initial MPC determination based upon quality assured historical data recorded by the CEMS. If this option is chosen, the MPC shall be the maximum SO_2 concentration observed during the previous 720 (or more) quality assured monitor operating hours when combusting the highest-sulfur fuel (or highest-sulfur blend if fuels are always blended or co-fired) that is to be combusted in the unit or units monitored by the SO_2 monitor. For units with SO_2 emission controls, the certified SO_2 monitor used to determine the MPC must be located at or before the control device inlet. Report the MPC and the method of determination in the monitoring plan required under § 75.53.

(c) When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D3177–89, ''Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke''; ASTM D4239–85, ''Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods''; ASTM D4294–90, ''Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy''; ASTM D1552–90, ''Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)''; ASTM D129–91, ''Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)''; ASTM D2622–92, ''Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry'' for sulfur content of solid or liquid fuels; ASTM D3176–89, ''Standard Practice for Ultimate Analysis of Coal and Coke''; ASTM D240–87 (Reapproved 1991), ''Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter''; or ASTM D2015–91, ''Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter'' for GCV (incorporated by reference under § 75.6).

$$\text{MPC (or MEC)} = 11.32 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{20.9 - \%O_{2w}}{20.9}\right) \qquad \text{(Eq. A-1a)}$$

or

$$\text{MPC (or MEC)} = 66.93 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{\%CO_{2w}}{100}\right) \qquad \text{(Eq. A-1b)}$$

Where,

MPC = Maximum potential concentration (ppm, wet basis). (To convert to dry basis, divide the MPC by 0.9.)

MEC = Maximum expected concentration (ppm, wet basis). (To convert to dry basis, divide the MEC by 0.9).

%S = Maximum sulfur content of fuel to be fired, wet basis, weight percent, as determined by ASTM D3177–89, ASTM D4239–85, ASTM D4294–90, ASTM D1552–90, ASTM D129–91, or ASTM D2622–92 for solid or liquid fuels (incorporated by reference under § 75.6).

$\%O_{2w}$ = Minimum oxygen concentration, percent wet basis, under typical operating conditions.

$\%CO_{2w}$ = Maximum carbon dioxide concentration, percent wet basis, under typical operating conditions.

11.32×10^6 = Oxygen-based conversion factor in Btu/lb (ppm)/%.

66.93×10^6 = Carbon dioxide-based conversion factor in Btu/lb (ppm)/%.

Note: All percent values to be inserted in the equations of this section are to be expressed as a percentage, not a fractional value (e.g., 3, not .03).

2.1.1.2 Maximum Expected Concentration

(a) Make an initial determination of the maximum expected concentration (MEC) of SO_2 whenever: (a) SO_2 emission controls are used; or (b) both high-sulfur and low-sulfur fuels (e.g., high-sulfur coal and low-sulfur coal or different grades of fuel oil) or high-sulfur and low-sulfur fuel blends are combusted as primary or backup fuels in a unit without SO_2 emission controls. For units with SO_2 emission controls, use Equation A–2 to make the initial MEC determination. When high-sulfur and low-sulfur fuels or blends are burned as primary or backup fuels in a unit without SO_2 controls, use Equation A–1a or A–1b to calculate the initial MEC value for each fuel or blend, except for: (1) the highest-sulfur fuel or blend (for which the MPC was previously calculated in section 2.1.1.1 of this appendix); (2) fuels or blends that are very low sulfur fuels (as defined in § 72.2 of this chapter); or (3) fuels or blends that are used only for unit startup.

(b) For each MEC determination, substitute into Equation A–1a or A–1b the highest sulfur content and minimum GCV value for that fuel or blend, based upon all available fuel sampling and analysis results from the previous 12 months (or more), or, if fuel sampling data are unavailable, based upon fuel contract(s).

(c) Alternatively, if a certified SO_2 CEMS is already installed, the owner or operator may make the initial MEC determination(s) based upon historical monitoring data. If this option is chosen for a unit with SO_2 emission controls, the MEC shall be the maximum SO_2 concentration measured downstream of the control device outlet by the CEMS over the previous 720 (or more) quality assured monitor operating hours with the unit and the control device both operating normally. For units that burn high- and low-sulfur fuels or blends as primary and backup fuels and have no SO_2 emission controls, the MEC for each fuel shall be the maximum SO_2 concentration measured by the CEMS over the previous 720 (or more) quality assured monitor operating hours in which that fuel or blend was the only fuel being burned in the unit.

$$MEC = MPC \left(\frac{100 - RE}{100} \right) \qquad \text{(Eq. A-2)}$$

Where:

MEC = Maximum expected concentration (ppm).

MPC = Maximum potential concentration (ppm), as determined by Eq. A–1a or A–1b.

RE = Expected average design removal efficiency of control equipment (%).

2.1.1.3 Span Value(s) and Range(s)

Determine the high span value and the high full-scale range of the SO_2 monitor as follows. (Note: For purposes of this part, the high span and range refer, respectively, either to the span and range of a single span unit or to the high span and range of a dual span unit.) The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the span value upward to the next highest multiple of 100 ppm. If the SO_2 span concentration is ≤500 ppm, the span value may be rounded upward to the next highest multiple of 10 ppm, instead of the nearest 100 ppm. The high span value shall be used to determine concentrations of the calibration gases required for daily calibration error checks and linearity tests. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Report the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit. Note that for certain applications, a second (low) SO_2 span and range may be required (see section 2.1.1.4 of this appendix). If an existing state, local, or federal requirement for span of an SO_2 pollutant concentration monitor requires a span 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. Span values higher than those required by either this section or section 2.1.1.4 of this appendix must be approved by the Administrator.

2.1.1.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.1.3 of this appendix will suffice to measure and record SO_2 concentrations (unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all possible or expected SO_2 concentrations. To determine whether two SO_2 span values are required, proceed as follows:

(a) For units with SO_2 emission controls, compare the MEC from section 2.1.1.2 of this appendix to the high full-scale range value from section 2.1.1.3 of this appendix. If the MEC is ≥20.0 percent of the high range value, then the high span value and range determined under section 2.1.1.3 of this appendix are sufficient. If the MEC is <20.0 percent of the high range value, then a second (low) span value is required.

(b) For units that combust high- and low-sulfur primary and backup fuels (or blends) and have no SO_2 controls, compare the high range value from section 2.1.1.3 of this appendix (for the highest-sulfur fuel or blend) to the MEC value for each of the other fuels or blends, as determined under section 2.1.1.2 of this appendix. If all of the MEC values are ≥20.0 percent of the high range value, the high span and range determined under section 2.1.1.3 of this appendix are sufficient, regardless of which fuel or blend is burned in the unit. If any MEC value is <20.0 percent of the high range value, then a second (low) span value must be used when that fuel or blend is combusted.

(c) When two SO_2 spans are required, the owner or operator may either use a single SO_2 analyzer with a dual range (i.e., low- and high-scales) or two separate SO_2 analyzers connected to a common sample probe and sample interface. For units with SO_2 emission controls, the owner or operator may use a low range analyzer and a default high range value, as described in paragraph (f) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.

(d) The owner or operator shall designate the monitoring systems and components in the monitoring plan under § 75.53 as follows: designate the low and high monitor ranges as separate SO_2 components of a single, primary SO_2 monitoring system; or designate the low and high monitor ranges as the SO_2 components of two separate, primary SO_2 monitoring systems; or 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)); or, 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. Do not designate the default high range as a monitoring system or component. Other component and system designations are subject to approval by the Administrator. Note that the component and system designations for redundant backup monitoring systems shall be the same as for primary monitoring systems.

(e) Each monitoring system designated as primary or redundant backup shall meet the initial certification and quality assurance requirements for primary monitoring systems in § 75.20(c) or § 75.20(d)(1), as applicable, and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for units with SO_2 emission controls, the low range is considered normal). Each monitoring system designated as a non-redundant backup shall meet the applicable quality assurance requirements in § 75.20(d)(2).

(f) For dual span units with SO_2 emission controls, the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default SO_2 concentration of 200 percent of the MPC for each unit operating hour in which the full-scale of the low range SO_2 analyzer is exceeded.

(g) The high span value and range shall be determined in accordance with section 2.1.1.3 of this appendix. The low span value shall be obtained by multiplying the MEC by a factor no less than 1.00 and no greater than 1.25, and rounding the result upward to the next highest multiple of 10 ppm (or 100 ppm, as appropriate). For units that burn high- and low-sulfur primary and backup fuels or blends and have no SO_2 emission controls, select, as the basis for calculating the appropriate low span value and range, the fuel-specific MEC value closest to 20.0 percent of the high full-scale range value (from paragraph (b) of this section). The low range must be greater than or equal to the low span value, and the required calibration gases must be selected based on the low span value. For units with two SO_2 spans, use the low range whenever the SO_2 concentrations are expected to be consistently below 20.0 percent of the high full-scale range value, i.e., when the MEC of the fuel or blend being combusted is less than 20.0 percent of the high full-scale range value. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the SO_2 concentrations; or, if applicable, the default high range value in paragraph (f) of this section shall be reported for each hour of the full-scale exceedance.

2.1.1.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each SO_2 monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a) and (b) of this section. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section, SO_2 data recorded during short-term, non-representative process operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

(a) If the fuel supply, the composition of the fuel blend(s), the emission controls, or the manner of operation change such that the maximum expected or potential concentration changes significantly, adjust the span and range setting to assure the continued accuracy of the monitoring system. A "significant" change in the MPC or MEC means that the guidelines in section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit may affect the concentration of emissions being emitted from the unit or stack and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. Determine the adjusted span(s) using the procedures in sections 2.1.1.3 and 2.1.1.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the new span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.

(b) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:

(1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly SO_2 concentration for each hour of the full-scale exceedance and make appropriate adjustments to the MPC, span, and range to prevent future full-scale exceedances.

(2) For units with two SO_2 spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and is not out-of-control or out-of-service for any reason. However, if the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the SO_2 concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded follow the procedures in paragraph (b)(1) of this section).

(c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the SO_2 monitor, as described in paragraphs (a) or (b) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC and calculations of the adjusted span value in an updated monitoring plan. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check specified by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is so significant that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, then a diagnostic linearity test using the new calibration gases must be performed and passed. Data from the monitor are considered invalid from the hour in which the span is adjusted until the required linearity check is passed in accordance with section 6.2 of this appendix.

2.1.2 NO_X Pollutant Concentration Monitors

Determine, as indicated in section 2.1.2.1, the span and range value(s) for the NO_X pollutant concentration monitor so that all expected NO_X concentrations can be determined and recorded accurately.

2.1.2.1 Maximum Potential Concentration

(a) The maximum potential concentration (MPC) of NO_X for each affected unit shall be based upon whichever fuel or blend combusted in the unit produces the highest level of NO_X emissions. Make an initial determination of the MPC using the appropriate option as follows:

Option 1: Use 800 ppm for coal-fired and 400 ppm for oil- or gas-fired units as the maximum potential concentration of NO_X (if an MPC of 1600 ppm for coal-fired units or 480 ppm for oil- or gas-fired units was previously selected under this part, that value may still be used, provided that the guidelines of section 2.1 of this appendix are met);

Option 2: Use the specific values based on boiler type and fuel combusted, listed in Table 2–1 or Table 2–2;

Option 3: Use NO_X emission test results; or

Option 4: Use historical CEM data over the previous 720 (or more) unit operating hours when combusting the fuel or blend with the highest NO_X emission rate.

(b) For the purpose of providing substitute data during NO_X missing data periods in accordance with §§ 75.31 and 75.33 and as required elsewhere under this part, the owner or operator shall also calculate the maximum potential NO_X emission rate (MER), in lb/mmBtu, by substituting the MPC for NO_X in conjunction with the minimum expected CO_2 or maximum O_2 concentration (under all unit operating conditions except for unit startup, shutdown, and upsets) and the appropriate F-factor into the applicable equation in appendix F to this part. The diluent cap value of 5.0 percent CO_2 (or 14.0 percent O_2) for boilers or 1.0 percent CO_2 (or 19.0 percent O_2) for combustion turbines may be used in the NO_X MER calculation.

(c) Report the method of determining the initial MPC and the calculation of the maximum potential NO_X emission rate in the monitoring plan for the unit.

(d) For units with add-on NO_X controls (whether or not the unit is equipped with low-NO_X burner 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. If NO_X emission testing is performed, use the following guidelines. Use Method 7E from appendix A to part 60 of this chapter to measure total NO_X concentration. (Note: Method 20 from appendix A to part 60 may be used for gas turbines, instead of Method 7E.) Operate the unit, or group of units sharing a common stack, at the minimum safe and stable load, the normal load, and the maximum load. If the normal load and maximum load are identical, an intermediate level need not be tested. Operate at the highest excess O_2 level expected under normal operating conditions. Make at least three runs of 20 minutes (minimum) duration with three traverse points per run at each operating condition. Select the highest point NO_X concentration from all test runs as the MPC for NO_X.

(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, 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 a unit with add-on NO_X controls (whether or not the unit is equipped with low-NO_X burner 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. The highest hourly NO_X concentration in ppm shall be the MPC.

TABLE 2–1.—MAXIMUM POTENTIAL CONCENTRATION FOR NO_X—COAL-FIRED UNITS

Unit type	Maximum potential concentration for NO_X (ppm)
Tangentially-fired dry bottom and fluidized bed	460
Wall-fired dry bottom, turbo-fired dry bottom, stokers	675
Roof-fired (vertically-fired) dry bottom, cell burners, arch-fired	975
Cyclone, wall-fired wet bottom, wet bottom turbo-fired	1200
Others	([1])

[1] As approved by the Administrator.

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 or combined cycle turbine	200
New stationary gas turbine/combustion turbine	50
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). 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; or (2) using historical CEM data over the previous 720 (or more) quality assured monitor operating hours. Include in the monitoring plan for the unit each MEC value and the method by which the MEC was determined.

(b) If NO_X emission testing is used to determine the MEC value(s), the MEC for each type of fuel (or blend) shall be based upon testing at minimum load, normal load, and maximum load. At least three tests of 20 minutes (minimum) duration, using at least three traverse points, shall be performed at each load, using Method 7E from appendix A to part 60 of this chapter (Note: Method 20 from appendix A to part 60 may be used for gas turbines instead of Method 7E). The test must be performed at a time when all NO_X control devices and methods used to reduce NO_X emissions are operating properly. The testing shall be conducted downstream of all NO_X controls. The highest point NO_X concentration (e.g., the highest one-minute average) recorded during any of the test runs shall be the MEC.

(c)If historical CEM data are used to determine the MEC value(s), the MEC for each type of fuel shall be based upon 720 (or more) hours of quality assured data representing the entire load range under stable operating conditions. The data base for the MEC shall not include any CEM data recorded during unit startup, shutdown, or malfunction or during any NO_X control device malfunctions or outages. All NO_X control devices and methods used to reduce NO_X emissions must be operating properly during each hour. The CEM data shall be collected downstream of all NO_X controls. For each type of fuel, the highest of the 720 (or more) quality assured hourly average NO_X concentrations recorded by the CEMS shall be the MEC.

2.1.2.3 Span Value(s) and Range(s)

(a) Determine the high span value of the NO_X monitor as follows. The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the span value upward to the next highest multiple of 100 ppm. If the NO_X span concentration is $\leq$ 500 ppm, the span value may be rounded upward to the next highest multiple of 10 ppm, rather than 100 ppm. The high span value shall be used to determine the concentrations of the calibration gases required for daily calibration error checks and linearity tests. Note that for certain applications, a second (low) NO_X span and range may be required (see section 2.1.2.4 of this appendix).

(b) If an existing State, local, or federal requirement for span of a NO_X pollutant concentration monitor requires a span lower than that required by this section or by section 2.1.2.4 of this appendix, the State, local, or federal span value may be used, where a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.2.5 of this appendix. Span values higher than required by this section or by section 2.1.2.4 of this appendix must be approved by the Administrator.

(c) Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the high span value. Include the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit.

2.1.2.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.2.3 of this appendix will suffice to measure and record NO_X concentrations (unless span and/or range adjustments must be made in accordance with section 2.1.2.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all expected and potential NO_X concentrations. To determine whether two NO_X spans are required, proceed as follows:

(a) Compare the MEC value(s) determined in section 2.1.2.2 of this appendix to the high full-scale range value determined in section 2.1.2.3 of this appendix. If the MEC values for all fuels (or blends) are $\geq$20.0 percent of the high range value, the high span and range values determined under section 2.1.2.3 of this appendix are sufficient, irrespective of which fuel or blend is combusted in the unit. If any of the MEC values is <20.0 percent of the high range value, two spans (low and high) are required, one based on the MPC and the other based on the MEC.

(b) When two NO_X spans are required, the owner or operator may either use a single NO_X analyzer with a dual range (low-and high-scales) or two separate NO_X analyzers connected to a common sample probe and sample interface. For units with add-on NO_X emission controls (i.e., steam injection, water injection, SCR, or SNCR), 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. Other monitor configurations are subject to the approval of the Administrator.

(c) The owner or operator shall designate the monitoring systems and components in the monitoring plan under § 75.53 as follows: designate the low and high ranges as separate NO_X components of a single, primary NO_X monitoring system; or designate the low and high ranges as the NO_X components of two separate, primary NO_X monitoring systems; or 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)); or, for units with add-on NO_X controls, 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. Do not designate the default high range as a monitoring system or component. Other component and system designations are subject to approval by the Administrator. Note that the component and system designations for redundant backup monitoring systems shall be the same as for primary monitoring systems.

(d) Each monitoring system designated as primary or redundant backup shall meet the initial certification and quality assurance requirements in § 75.20(c) (for primary monitoring systems), in § 75.20(d)(1) (for redundant backup monitoring systems) and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for dual span units with add-on NO_X emission controls, the low range is considered normal). Each monitoring system designated as non-redundant backup shall meet the applicable quality assurance requirements in § 75.20(d)(2).

(e) For dual span units with add-on NO_X emission controls (e.g., steam injection, water injection, SCR, or SNCR), the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default value of 200.0 percent of the MPC for each unit operating hour in which the full-scale of the low range NO_X analyzer is exceeded.

(f) The high span and range shall be determined in accordance with section 2.1.2.3 of this appendix. The low span value shall be 100.0 to 125.0 percent of the MEC, rounded up to the next highest multiple of 10 ppm (or 100 ppm, if appropriate). If more than one MEC value (as determined in section 2.1.2.2 of this appendix) is <20.0 percent of the high full-scale range value, the low span value shall be based upon whichever MEC value is closest to 20.0 percent of the high range value. The low range must be greater than or equal to the low span value, and the required calibration gases for the low range must be selected based on the low span value. For units with two NO_X spans, use the low range whenever NO_X concentrations are expected to be consistently <20.0 percent of the high range value, i.e., when the MEC of the fuel being combusted is <20.0 percent of the high range value. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the NO_X concentrations; or, if applicable, the default high range value in paragraph (e) of this section shall be reported for each hour of the full-scale exceedance.

2.1.2.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPC, MEC, span, and range values for each NO_X monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a) and (b) of this section. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section, note that NO_X data recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

(a) If the fuel supply, emission controls, or other process parameters change such that the maximum expected concentration or the maximum potential concentration changes significantly, adjust the NO_X pollutant concentration span(s) and (if necessary) monitor range(s) to assure the continued accuracy of the monitoring system. A ''significant'' change in the MPC or MEC means that the guidelines in section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit or stack may affect the concentration of emissions being emitted from the unit and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. An example of a change that may require a span and range adjustment is the installation of low-NO_X burner technology on a previously uncontrolled unit. Determine the adjusted span(s) using the procedures in section 2.1.2.3 or 2.1.2.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the adjusted span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.

(b) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:

(1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly NO_X concentration for each hour of the full-scale exceedance and make appropriate adjustments to the MPC, span, and range to prevent future full-scale exceedances.

(2) For units with two NO_X spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and is not out-of-control or out-of-service for any reason. However, if the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the NO_X concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded, follow the procedures in paragraph (b)(1) of this section).

(c) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the NO_X monitor as described in paragraphs (a) and (b) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC, maximum potential NO_X emission rate, and the adjusted span value in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check required by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is significant enough that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, a linearity test using the new calibration gases must be performed and passed. Data from the monitor are considered invalid from the hour in which the span is adjusted until the required linearity check is passed in accordance with section 6.2 of this appendix.

2.1.3 CO_2 and O_2 Monitors

For an O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percentage moisture), select a span value between 15.0 and 25.0 percent O_2. For a CO_2 monitor installed on a boiler, select a span value between 14.0 and 20.0 percent CO_2. For a CO_2 monitor installed on a combustion turbine, an alternative span value between 6.0 and 14.0 percent CO_2 may be used. An alternative O_2 span value below 15.0 percent O_2 may be used if an appropriate technical justification is included in the monitoring plan (e.g., O_2 concentrations above a certain level create an unsafe operating condition).

Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Select the calibration gas concentrations for the daily calibration error tests and linearity checks in accordance with section 5.1 of this appendix, as percentages of the span value. For O_2 monitors with span values ≥21.0 percent O_2, purified instrument air containing 20.9 percent O_2 may be used as the high-level calibration material.

2.1.3.1 Maximum Potential Concentration of CO_2

For CO_2 pollutant concentration monitors, the maximum potential concentration shall be 14.0 percent CO_2 for boilers and 6.0 percent CO_2 for combustion turbines. Alternatively, the owner or operator may determine the MPC based on a minimum of 720 hours of quality assured historical CEM data representing the full operating load range of the unit(s). Note that the MPC for CO_2 monitors shall only be used for the purpose of providing substitute data under this part. The CO_2 monitor span and range shall be determined according to section 2.1.3 of this appendix.

2.1.3.2 Minimum Potential Concentration of O_2

The owner or operator of a unit that uses a flow monitor and an O_2 diluent monitor to determine heat input in accordance with Equation F–17 or F–18 in appendix F to this part shall, for the purposes of providing substitute data under § 75.36, determine the minimum potential O_2 concentration. The minimum potential O_2 concentration shall be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). The minimum potential O_2 concentration shall be the lowest quality-assured hourly average O_2 concentration recorded in the 720 (or more) hours of data used for the determination.

2.1.3.3 Adjustment of Span and Range

Adjust the span value and range of a CO_2 or O_2 monitor in accordance with section 2.1.1.5 of this appendix (insofar as those provisions are applicable), with the term ''CO_2 or O_2'' applying instead of the term ''SO_2''. Set the new span and range in accordance with section 2.1.3 of this appendix and report the new span value in the monitoring plan.

2.1.4 Flow Monitors

Select the full-scale range of the flow monitor so that it is consistent with section 2.1 of this appendix and can accurately measure all potential volumetric flow rates at the flow monitor installation site.

2.1.4.1 Maximum Potential Velocity and Flow Rate

For this purpose, determine the span value of the flow monitor using the following procedure. Calculate the maximum potential velocity (MPV) using Equation A–3a or A–3b or determine the MPV (wet basis) from velocity traverse testing using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter. If using test values, use the highest average velocity (determined from the Method 2 traverses) measured at or near the maximum unit operating load. Express the MPV in units of wet standard feet per minute (fpm). For the purpose of providing substitute data during periods of missing flow rate data in accordance with §§ 75.31 and 75.33 and as required elsewhere in this part, calculate the maximum potential stack gas flow rate (MPF) in units of standard cubic feet per hour (scfh), as the product of the MPV (in units of wet, standard fpm) times 60, times the cross-sectional area of the stack or duct (in ft²) at the flow monitor location.

$$MPV = \left(\frac{F_d H_f}{A}\right)\left(\frac{20.9}{20.9 - \%O_{2d}}\right)\left(\frac{100}{100 - \%H_2O}\right) \qquad (\text{Eq. A-3a})$$

or

$$MPV = \left(\frac{F_c H_f}{A}\right)\left(\frac{100}{\%CO_{2d}}\right)\left(\frac{100}{100 - \%H_2O}\right) \qquad (\text{Eq. A-3b})$$

Where:

MPV = maximum potential velocity (fpm, standard wet basis).
F_d = dry-basis F factor (dscf/mmBtu) from Table 1, Appendix F to this part.
F_c = carbon-based F factor (scf CO_2/mmBtu) from Table 1, Appendix F to this part.
Hf = maximum heat input (mmBtu/minute) for all units, combined, exhausting to the stack or duct where the flow monitor is located.
A = inside cross sectional area (ft²) of the flue at the flow monitor location.
$\%O_{2d}$ = maximum oxygen concentration, percent dry basis, under normal operating conditions.
$\%CO_{2d}$ = minimum carbon dioxide concentration, percent dry basis, under normal operating conditions.
$\%H_2O$ = maximum percent flue gas moisture content under normal operating conditions.

2.1.4.2 Span Values and Range

Determine the span and range of the flow monitor as follows. Convert the MPV, as determined in section 2.1.4.1 of this appendix, to the same measurement units of flow rate that are used for daily calibration error tests (e.g., scfh, kscfh, kacfm, or differential pressure (inches of water)). Next, determine the ''calibration span value'' by multiplying the MPV (converted to equivalent daily calibration error units) by a factor no less than 1.00 and no greater than 1.25, and rounding up the result to at least two significant figures. For calibration span values in inches of water, retain at least two decimal places. Select appropriate reference signals for the daily calibration error tests as percentages of the calibration span value. Finally, calculate the ''flow rate span value'' (in scfh) as the product of the MPF, as determined in section 2.1.4.1 of this appendix, times the same factor (between 1.00 and 1.25) that was used to calculate the calibration span value. Round off the flow rate span value to the nearest 1000 scfh. Select the full-scale range of the flow monitor so that it is greater than or equal to the span value and is consistent with section 2.1 of this appendix. Include in the monitoring plan for the unit: calculations of the MPV, MPF, calibration span value, flow rate span value, and full-scale range (expressed both in scfh and, if different, in the measurement units of calibration).

2.1.4.3 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a periodic evaluation of the MPV, MPF, span, and range values for each flow rate monitor (at a minimum, an annual evaluation is required) and shall make any necessary span and range adjustments with corresponding monitoring plan updates, as described in paragraphs (a) through (c) of this section 2.1.4.3. Span and range adjustments may be required, for example, as a result of changes in the fuel supply, changes in the stack or ductwork configuration, changes in the manner of operation of the unit, or installation or removal of emission controls. In implementing the provisions in paragraphs (a) and (b) of this section 2.1.4.3, note that flow rate data recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from consideration. The owner or operator shall keep the results of the most recent span and range evaluation on-site, in a format suitable for inspection. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified.

(a) If the fuel supply, stack or ductwork configuration, operating parameters, or other conditions change such that the maximum potential flow rate changes significantly, adjust the span and range to assure the continued accuracy of the flow monitor. A ''significant'' change in the MPV or MPF means that the guidelines of section 2.1 of this appendix can no longer be met, as determined by either a periodic evaluation by the owner or operator or from the results of an audit by the Administrator. The owner or operator should evaluate whether any planned changes in operation of the unit may affect the flow of the unit or stack and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. Calculate the adjusted calibration span and flow rate span values using the procedures in section 2.1.4.2 of this appendix.

(b) Whenever the full-scale range is exceeded during a quarter, provided that the exceedance is not caused by a monitor out-of-control period, report 200.0 percent of the current full-scale range as the hourly flow rate for each hour of the full-scale exceedance. If the range is exceeded, make appropriate adjustments to the MPF, flow rate span, and range to prevent future full-scale exceedances. Calculate the new calibration span value by converting the new flow rate span value from units of scfh to units of daily calibration. A calibration error test must be performed and passed to validate data on the new range.

(c) Whenever changes are made to the MPV, MPF, full-scale range, or span value of the flow monitor, as described in paragraphs (a) and (b) of this section, record and report (as applicable) the new full-scale range setting, calculations of the flow rate span value, calibration span value, MPV, and MPF in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. Record and report the adjusted calibration span and reference values as parts of the records for the calibration error test required by appendix B to this part. Whenever the calibration span value is adjusted, use reference values for the calibration error test that meet the requirements of section 2.2.2.1 of this appendix, based on the most recent adjusted calibration span value. Perform a calibration error test according to section 2.1.1 of appendix B to this part whenever making a change to the flow monitor span or range, unless the range change also triggers a recertification under § 75.20(b).

2.1.5 Minimum Potential Moisture Percentage

Except as provided in section 2.1.6 of this appendix, the owner or operator of a unit that uses a continuous moisture monitoring system to correct emission rates and heat inputs from a dry basis to a wet basis (or vice-versa) shall, for the purpose of providing substitute data under § 75.37, use a default value of 3.0 percent H_2O as the minimum potential moisture percentage. Alternatively, the minimum potential moisture percentage may be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). If this option is chosen, the minimum potential moisture percentage shall be the lowest quality-assured hourly average H_2O concentration recorded in the 720 (or more) hours of data used for the determination.

2.1.6 Maximum Potential Moisture Percentage

When Equation 19–3, 19–4 or 19–8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate, the owner or operator of a unit that uses a continuous moisture monitoring system shall, for the purpose of providing substitute data under § 75.37, determine the maximum potential moisture percentage. The maximum potential moisture percentage shall be based upon 720 hours or more of quality-assured CEM data, representing the full operating load range of the unit(s). The maximum potential moisture percentage shall be the highest quality-assured hourly average H_2O concentration recorded in the 720 (or more) hours of data used for the determination.

55. Appendix A to part 75 is amended by revising section 3.1, the last sentence in the first paragraph of section 3.2, and section 3.3.2; by adding section 3.3.6; and by revising sections 3.3.7, 3.4.1 and 3.5 to read as follows:

3. Performance Specifications

3.1 Calibration Error

(a) The calibration error performance specifications in this section apply only to 7-day calibration error tests under sections 6.3.1 and 6.3.2 of this appendix and to the offline calibration demonstration described in section 2.1.1.2 of appendix B to this part. The calibration error limits for daily operation of the continuous monitoring systems required under this part are found in section 2.1.4(a) of appendix B to this part.

(b) The calibration error of SO_2 and NO_X pollutant concentration monitors shall not deviate from the reference value of either the zero or upscale calibration gas by more than 2.5 percent of the span of the instrument, as calculated using Equation A–5 of this appendix. Alternatively, where the span value is less than 200 ppm, calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value, |R–A − in Equation A–5 of this appendix, is ≤5 ppm. The calibration error of CO_2 or O_2 monitors (including O_2 monitors used to measure CO_2 emissions or percent moisture) shall not deviate from the reference value of the zero or upscale calibration gas by >0.5 percent O_2 or CO_2, as calculated using the term −R–A| in the numerator of Equation A–5 of this appendix. The calibration error of flow monitors shall not exceed 3.0 percent of the calibration span value of the instrument, as calculated using Equation A–6 of this appendix. For differential pressure-type flow monitors, the calibration error test results are also acceptable if |R–A|, the absolute value of the difference between the monitor response and the reference value in Equation A–6, does not exceed 0.01 inches of water.

3.2 Linearity Check

* * * For CO_2 or O_2 monitors (including O_2 monitors used to measure CO_2 emissions or percent moisture):

* * * * *

3.3 * * *

3.3.2 Relative Accuracy for NO_X-Diluent Continuous Emission Monitoring Systems

(a) The relative accuracy for NO_X-diluent continuous emission monitoring systems shall not exceed 10.0 percent.

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

* * * * *

3.3.6 Relative Accuracy for Moisture Monitoring Systems

The relative accuracy of a moisture monitoring system shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the mean difference of the reference method measurements (in percent H_2O) and the corresponding moisture monitoring system measurements (in percent H_2O), calculated using Equation A–7 of this appendix, are within ±1.5 percent H_2O.

3.3.7 Relative Accuracy for NO_X Concentration Monitoring Systems

(a) The following requirement applies only to NO_X concentration monitoring systems (i.e., NO_X pollutant concentration monitors) that are used to determine NO_X mass emissions, where the owner or operator elects to monitor and report NO_X mass emissions using a NO_X concentration monitoring system and a flow monitoring system.

(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 monitoring system measurements of NO_X concentration during the relative accuracy test audit is less than or equal to 250.0 ppm, the mean value of the continuous emission monitoring system measurements shall not exceed ±15.0 ppm of the reference method mean value.

3.4 * * *

3.4.1 SO_2 Pollutant Concentration Monitors, NO_X Concentration Monitoring Systems and NO_X-Diluent Continuous Emission Monitoring Systems

SO_2 pollutant concentration monitors, NO_X-diluent continuous emission monitoring systems and NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in § 75.71(a)(2), shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO_2 pollutant concentration monitors and to all NO_X concentration monitoring systems, including those measuring an average SO_2 or NO_X concentration of 250.0 ppm or less, and to all NO_X-diluent continuous emission monitoring systems, including those measuring an average NO_X emission rate of 0.200 lb/mmBtu or less.

* * * * *

3.5 Cycle Time

The cycle time for pollutant concentration monitors, oxygen monitors used to determine percent moisture, and any other continuous emission monitoring system(s) required to perform a cycle time test shall not exceed 15 minutes.

56. Appendix A to part 75 is amended by revising the first sentence of the first paragraph of section 4 and paragraph (6) to read as follows:

4. Data Acquisition and Handling Systems

Automated data acquisition and handling systems shall read and record the full range of pollutant concentrations and volumetric flow from zero through span and provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission both by direct computer-to-computer electronic transfer via modem and EPA-provided software and by an IBM-compatible personal computer diskette.

* * * * *

(6) Provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission both by direct computer-to-computer electronic transfer via modem and EPA-provided software and by an IBM-compatible personal computer diskette.

57. Appendix A to part 75 is amended by revising sections 5 through 5.1.6, adding sections 5.1.7 through 5.1.8, and revising sections 5.2 through 5.2.4 to read as follows:

5. Calibration Gas

5.1 Reference Gases

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

5.1.1 Standard Reference Materials (SRM)

These calibration gases may be obtained from the National Institute of Standards and Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg, MD 20899–0001.

5.1.2 SRM-Equivalent Compressed Gas Primary Reference Material (PRM)

Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and Technology Laboratory of NIST, at the address in section 5.1.1, for a list of vendors and cylinder gases.

5.1.3 NIST Traceable Reference Materials

Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and Technology Laboratory of NIST, at the address in section 5.1.1, for a list of vendors and cylinder gases.

5.1.4 EPA Protocol Gases

(a) EPA Protocol gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value), using the uncertainty calculation procedure in section 2.1.8 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121.

(b) A copy of EPA–600/R–97/121 is available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA, 703–487–4650 and from the Office of Research and Development, (MD–77B), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

5.1.5 Research Gas Mixtures

Research gas mixtures must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value), using the uncertainty calculation procedure in section 2.1.8 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121. Inquiries about the RGM program should be directed to: National Institute of Standards and Technology, Analytical Chemistry Division, Chemical Science and Technology Laboratory, B–324 Chemistry, Gaithersburg, MD 20899.

5.1.6 Zero Air Material

Zero air material is defined in § 72.2 of this chapter.

5.1.7 NIST/EPA-Approved Certified Reference Materials

Existing certified reference materials (CRMs) that are still within their certification period may be used as calibration gas.

5.1.8 Gas Manufacturer's Intermediate Standards

Gas manufacturer's intermediate standards is defined in § 72.2 of this chapter.

5.2 Concentrations

Four concentration levels are required as follows.

5.2.1 Zero-level Concentration

0.0 to 20.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.2 Low-level Concentration

20.0 to 30.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.3 Mid-level Concentration

50.0 to 60.0 percent of span, including span for high-scale or both low- and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.4 High-level Concentration

80.0 to 100.0 percent of span, including span for high-scale or both low-and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

58. Appendix A to part 75 is amended by revising sections 6.2, 6.3.1, 6.3.2, 6.4, 6.5, 6.5.1, 6.5.2, 6.5.6, 6.5.7, 6.5.9 and 6.5.10, and adding sections 6.5.2.1, 6.5.2.2, 6.5.6.1, 6.5.6.2, and 6.5.6.3 to read as follows:

6. Certification Tests and Procedures

* * * * *

6.2 Linearity Check (General Procedures)

Check the linearity of each SO_2, NO_X, CO_2, and O_2 monitor while the unit, or group of units for a common stack, is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during this test. Notwithstanding these requirements, if the SO_2 or NO_X span value for a particular monitor range is $\leq$30 ppm, that range is exempted from the linearity test requirements of this part. For units using emission controls and other units using both a high and a low span, perform a linearity check on both the low- and high-scales for initial certification. For on-going quality assurance of the CEMS, perform linearity checks, using the procedures in this section, on the range(s) and at the frequency specified in section 2.2.1 of appendix B to this part. Challenge each monitor with calibration gas, as defined in section 5.1 of this appendix, at the low-, mid-, and high-range concentrations specified in section 5.2 of this appendix. Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor at its normal operating temperature and conditions. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in-situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the monitor three times with each reference gas (see example data sheet in Figure 1). Do not use the same gas twice in succession. To the extent practicable, the duration of each linearity test, from the hour of the first injection to the hour of the last injection, shall not exceed 24 unit operating hours. Record the monitor response from the data acquisition and handling system. For each concentration, use the average of the responses to determine the error in linearity using Equation A–4 in this appendix. Linearity checks are acceptable for monitor or monitoring system certification, recertification, or quality assurance if none of the test results exceed the applicable performance specifications in section 3.2 of this appendix. The status of emission data from a CEMS prior to and during a linearity test period shall be determined as follows:

(a) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the linearity test, have been successfully completed, unless the data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words ''initial certification'' apply instead of ''recertification,'' and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(b) For the routine quality assurance linearity checks required by section 2.2.1 of appendix B to this part, use the data validation procedures in section 2.2.3 of appendix B to this part.

(c) When a linearity test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

(d) For linearity tests of non-redundant backup monitoring systems, use the data validation procedures in § 75.20(d)(2)(iii).

(e) For linearity tests performed during a grace period and after the expiration of a grace period, use the data validation procedures in sections 2.2.3 and 2.2.4, respectively, of appendix B to this part.

(f) For all other linearity checks, use the data validation procedures in section 2.2.3 of appendix B to this part.

6.3 * * *

6.3.1 Gas Monitor 7-day Calibration Error Test

Measure the calibration error of each SO_2 monitor, each NO_X monitor and each CO_2 or O_2 monitor while the unit is combusting fuel (but not necessarily generating electricity) once each day for 7 consecutive operating days according to the following procedures. (In the event that extended unit outages occur after the commencement of the test, the 7 consecutive unit operating days need not be 7 consecutive calendar days.) Units using dual span monitors must perform the calibration error test on both high- and low-scales of the pollutant concentration monitor. The calibration error test procedures in this section and in section 6.3.2 of this appendix shall also be used to perform the daily assessments and additional calibration error tests required under sections 2.1.1 and 2.1.3 of appendix B to this part. Do not make manual or automatic adjustments to the monitor settings until after taking measurements at both zero and high concentration levels for that day during the 7-day test. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined and recorded. Record and report test results for each day using the unadjusted concentration measured in the calibration error test prior to making any manual or automatic adjustments (i.e., resetting the calibration). The calibration error tests should be approximately 24 hours apart, (unless the 7-day test is performed over non-consecutive days). Perform calibration error tests at both the zero-level concentration and high-level concentration, as specified in section 5.2 of this appendix. Alternatively, a mid-level concentration gas (50.0 to 60.0 percent of the span value) may be used in lieu of the high-level gas, provided that the mid-level gas is more representative of the actual stack gas concentrations. In addition, repeat the procedure for SO_2 and NO_X pollutant concentration monitors using the low-scale for units equipped with emission controls or other units with dual span monitors. Use only calibration gas, as specified in section 5.1 of this appendix. Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in-situ type monitors, perform calibration, checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the pollutant concentration monitors and CO_2 or O_2 monitors once with each calibration gas. Record the monitor response from the data acquisition and handling system. Using Equation A–5 of this appendix, determine the calibration error at each concentration once each day (at approximately 24-hour intervals) for 7 consecutive days according to the procedures given in this section. The results of a 7-day calibration error test are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of these daily calibration error test results exceed the applicable performance specifications in section 3.1 of this appendix.The status of emission data from a gas monitor prior to and during a 7-day calibration error test period shall be determined as follows:

(a) For initial certification, data from the monitor are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words ''initial certification'' apply instead of ''recertification,'' and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(b) When a 7-day calibration error test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

6.3.2 Flow Monitor 7-day Calibration Error Test

Perform the 7-day calibration error test of a flow monitor, when required for certification, recertification or diagnostic testing, according to the following procedures. Introduce the reference signal corresponding to the values specified in section 2.2.2.1 of this appendix to the probe tip (or equivalent), or to the transducer. During the 7-day certification test period, conduct the calibration error test while the unit is operating once each unit operating day (as close to 24-hour intervals as practicable). In the event that extended unit outages occur after the commencement of the test, the 7 consecutive operating days need not be 7 consecutive calendar days. Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A–6 of this appendix. Do not perform any corrective maintenance, repair, or replacement upon the flow monitor during the 7-day test period other than that required in the quality assurance/quality control plan required by appendix B to this part. Do not make adjustments between the zero and high reference level measurements on any day during the 7-day test. If the flow monitor operates within the calibration error performance specification (i.e., less than or equal to 3.0 percent error each day and requiring no corrective maintenance, repair, or replacement during the 7-day test period), the flow monitor passes the calibration error test. Record all maintenance activities and the magnitude of any adjustments. Record output readings from the data acquisition and handling system before and after all adjustments. Record and report all calibration error test results using the unadjusted flow rate measured in the calibration error test prior to resetting the calibration. Record all adjustments made during the 7-day period at the time the adjustment is made, and report them in the certification or recertification application. The status of emissions data from a flow monitor prior to and during a 7-day calibration error test period shall be determined as follows:

(a) For initial certification, data from the monitor are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words ''initial certification'' apply instead of ''recertification,'' and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(b) When a 7-day calibration error test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

6.4 Cycle Time Test

Perform cycle time tests for each pollutant concentration monitor and continuous emission monitoring system while the unit is operating, according to the following procedures (see also Figure 6 at the end of this appendix). Use a zero-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. To determine the upscale elapsed time, inject a zero-level concentration calibration gas into the probe tip (or injection port leading to the calibration cell, for in situ systems with no probe). Record the stable starting gas value and start time, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of flue gas emissions until the response stabilizes. Record the stable ending stack emissions value and the end time of the test using the DAHS. Determine the upscale elapsed time as the time it takes for 95.0 percent of the step change to be achieved between the stable starting gas value and the stable ending stack emissions value. Then repeat the procedure, starting by injecting the high-level gas concentration to determine the downscale elapsed time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable starting gas value and the stable ending stack emissions value. End the downscale test by measuring the stable concentration of flue gas emissions. Record the stable starting and ending monitor values, the start and end times, and the downscale elapsed time for the monitor using the DAHS. A stable value is equivalent to a reading with a change of less than 2.0 percent of the span value for 2 minutes, or a reading with a change of less than 6.0 percent from the measured average concentration over 6 minutes. (Owners or operators of systems which do not record data in 1-minute or 3-minute intervals may petition the Administrator under § 75.66 for alternative stabilization criteria). For monitors or monitoring systems that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible cycle time. Report the slower of the two elapsed times (upscale or downscale) as the cycle time for the analyzer. (See Figure 5 at the end of this appendix.) For the NOx-diluent continuous emission monitoring system test and SO_2-diluent continuous emission monitoring system test, record and report the longer cycle time of the two component analyzers as the system cycle time. For time-shared systems, this procedure must be done at all probe locations that will be polled within the same 15-minute period during monitoring system operations. To determine the cycle time for time-shared systems, add together the longest cycle time obtained at each of the probe locations. Report the sum of the longest cycle time at each of the probe locations plus the sum of the time required for all purge cycles (as determined by the continuous emission monitoring system manufacturer) at each of the probe locations as the cycle time for each of the time-shared systems. For monitors with dual ranges, report the test results from on the range giving the longer cycle time. Cycle time test results are acceptable for monitor or monitoring system certification, recertification or diagnostic testing if none of the cycle times exceed 15 minutes. The status of emissions data from a monitor prior to and during a cycle time test period shall be determined as follows:

(a) For initial certification, data from the monitor are considered invalid until all certification tests, including the cycle time test, have been successfully completed, unless the data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words ''initial certification'' apply instead of ''recertification,'' and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(b) When a cycle time test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

6.5 Relative Accuracy and Bias Tests (General Procedures)

Perform the required relative accuracy test audits (RATAs) as follows for each CO_2 pollutant concentration monitor (including O_2 monitors used to determine CO_2 pollutant concentration), each SO_2 pollutant concentration monitor, each NO_X concentration monitoring system used to determine NO_X mass emissions, each flow monitor, each NO_X-diluent continuous emission monitoring system, each O_2 or CO_2 diluent monitor used to calculate heat input, each moisture monitoring system and each SO_2-diluent continuous emission monitoring system. For NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in § 75.71(a)(2), use the same general RATA procedures as for SO_2 pollutant concentration monitors; however, use the reference methods for NO_X concentration specified in section 6.5.10 of this appendix:

(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 normal 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). When relative accuracy test audits are performed on continuous emission monitoring systems or component(s) 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.

(b) Perform each RATA at the load level(s) specified in section 6.5.1 or 6.5.2 of this appendix or in section 2.3.1.3 of appendix B to this part, as applicable.

(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 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), 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.

(d) Record monitor or monitoring system output from the data acquisition and handling system.

(e) Complete each single-load relative accuracy test audit within a period of 168 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for CEMS installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter). For 2-level and 3-level flow monitor RATAs, complete all of the RATAs at all levels, to the extent practicable, within a period of 168 consecutive unit (or stack) operating hours; however, if this is not possible, up to 720 consecutive unit (or stack) operating hours may be taken to complete a multiple-load flow RATA.

(f) The status of emission data from the CEMS prior to and during the RATA test period shall be determined as follows:

(1) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the RATA, have been successfully completed, unless the data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, the words ''initial certification'' apply instead of ''recertification,'' and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(2) For the routine quality assurance RATAs required by section 2.3.1 of appendix B to this part, use the data validation procedures in section 2.3.2 of appendix B to this part.

(3) For recertification RATAs, use the data validation procedures in § 75.20(b)(3).

(4) For quality assurance RATAs of non-redundant backup monitoring systems, use the data validation procedures in §§ 75.20(d)(2)(v) and (vi).

(5) For RATAs performed during and after the expiration of a grace period, use the data validation procedures in sections 2.3.2 and 2.3.3, respectively, of appendix B to this part.

(6) For all other RATAs, use the data validation procedures in section 2.3.2 of appendix B to this part.

(g) For each SO_2 or CO_2 pollutant concentration monitor, each flow monitor, each CO_2 or O_2 diluent monitor used to determine heat input, each NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2), each moisture monitoring system and each NO_X-diluent continuous emission monitoring system, calculate the relative accuracy, in accordance with section 7.3 or 7.4 of this appendix, as applicable. In addition (except for CO_2, O_2, SO_2-diluent or moisture monitors), test for bias and determine the appropriate bias adjustment factor, in accordance with sections 7.6.4 and 7.6.5 of this appendix, using the data from the relative accuracy test audits.

6.5.1 Gas Monitoring System RATAs (Special Considerations)

(a) Perform the required relative accuracy test audits for each SO_2 or CO_2 pollutant concentration monitor, each CO_2 or O2 diluent monitor used to determine heat input, each NO_X-diluent continuous emission monitoring system, each NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2), and each SO_2-diluent continuous emission monitoring system, at the normal load 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 have been designated as normal, the RATAs may be done at either load level.

(b) For the initial certification of a gas monitoring system and for recertifications in which, in addition to a RATA, one or more other tests are required (i.e., a linearity test, cycle time test, or 7-day calibration error test), EPA recommends that the RATA not be commenced until the other required tests of the CEMS have been passed.

6.5.2 Flow Monitor RATAs (Special Considerations)

(a) Except for flow monitors on bypass stacks/ducts and peaking units, perform relative accuracy test audits for the initial certification of each flow monitor at three different exhaust gas velocities (low, mid, and high), corresponding to three different load levels 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 combinations for the units exhausting to the common stack. Select the three exhaust gas velocities such that the audit points at adjacent load levels (i.e., low and mid or mid and high), in megawatts (or in thousands of lb/hr of steam production), 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.

(b) For flow monitors on bypass stacks/ducts and peaking units, the flow monitor relative accuracy test audits for initial certification and recertification shall be single-load tests, performed at the normal load, as defined in section 6.5.2.1 of this appendix.

(c) Flow monitor recertification RATAs shall be done at three load level(s), unless otherwise specified in paragraph (b) of this section or unless otherwise specified or approved by the Administrator.

(d) The semiannual and annual quality assurance flow monitor RATAs required under appendix B to this part shall be done at the load level(s) specified in section 2.3.1.3 of appendix B to this part.

6.5.2.1 Range of Operation and Normal Load Level(s)

(a) The owner or operator shall determine the upper and lower boundaries of the ''range of operation'' 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. The lower boundary of the range of operation of a unit shall be the minimum safe, stable load. For common stacks, the minimum safe, stable load shall be the lowest of the minimum safe, stable loads for any of the units discharging through the stack. Alternatively, for a group of frequently-operated units that serve a common stack, the sum of the minimum safe, stable loads for the individual units may be used as the lower boundary of the range of operation. The upper boundary of the range of operation of a unit shall be the maximum sustainable load. The ''maximum sustainable load'' is the higher of either: the nameplate or rated capacity of the unit, less any physical or regulatory limitations or other deratings; or the highest sustainable unit load, based on at least four quarters of representative historical operating data. For common stacks, the maximum sustainable load is the sum of all of the maximum sustainable loads of the individual units discharging through the stack, unless this load is unattainable in practice, in which case use the highest sustainable combined load for the units that discharge through the stack, based on at least four quarters of representative historical operating data. The load values for the unit(s) shall be expressed either in units of megawatts or thousands of lb/hr of steam load.

(b) The operating levels for relative accuracy test audits shall, except for peaking units, be defined as follows: the ''low'' operating level shall be the first 30.0 percent of the range of operation; the ''mid'' operating level shall be the middle portion (30.0 to 60.0 percent) of the range of operation; and the ''high'' operating level shall be the upper end (60.0 to 100.0 percent) of the range of operation. For example, if the upper and lower boundaries of the range of operation are 100 and 1100 megawatts, respectively, then the low, mid, and high operating levels would be 100 to 400 megawatts, 400 to 700 megawatts, and 700 to 1100 megawatts, respectively.

(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). This requirement becomes effective on April 1, 2000; however, the owner or operator may choose to comply with this requirement prior to April 1, 2000. 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.

(d) Based on the analysis of the historical load data the owner or operator shall 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.

(e) Beginning on April 1, 2000, 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, in the electronic quarterly report required under § 75.64. Except for peaking units, the owner or operator shall indicate, in the electronic quarterly report (as part of the electronic monitoring plan) the load level (or levels) designated as normal under this section and shall also indicate the two most frequently used load levels..

6.5.2.2 Multi-Load Flow RATA Results

For each multi-load 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 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.

* * * * *

6.5.6 Reference Method Traverse Point Selection

Select traverse points that ensure acquisition of representative samples of pollutant and diluent concentrations, moisture content, temperature, and flue gas flow rate over the flue cross section. To achieve this, the reference method traverse points shall meet the requirements of section 3.2 of Performance Specification 2 (''PS No. 2'') in appendix B to part 60 of this chapter (for SO_2, NO_X, and moisture monitoring system RATAs), Performance Specification 3 in appendix B to part 60 of this chapter (for O_2 and CO_2 monitor RATAs), Method 1 (or 1A) (for volumetric flow rate monitor RATAs), Method 3 (for molecular weight), and Method 4 (for moisture determination) in appendix A to part 60 of this chapter. Unless otherwise specified, use only codified versions of PS No. 2 revised as of July 1, 1995, July 1, 1996 or July 1, 1997. The following alternative reference method traverse point locations are permitted for moisture and gas monitor RATAs:

(a) For moisture determinations where the moisture data are used only to determine stack gas molecular weight, a single reference method point, located at least 1.0 meter from the stack wall, may be used. For moisture monitoring system RATAs and for gas monitor RATAs in which moisture data are used to correct pollutant or diluent concentrations from a dry basis to a wet basis (or vice-versa), single-point moisture sampling may only be used if the 12-point stratification test described in section 6.5.6.1 of this appendix is performed prior to the RATA for at least one pollutant or diluent gas, and if the test is passed according to the acceptance criteria in section 6.5.6.3(b) of this appendix.

(b) For gas monitoring system RATAs, the owner or operator may use any of the following options:

(1) At any location (including locations where stratification is expected), use a minimum of six traverse points along a diameter, in the direction of any expected stratification. The points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.

(2) At locations where section 3.2 of PS No. 2 allows the use of a short reference method measurement line (with three points located at 0.4, 1.0, and 2.0 meters from the stack wall), the owner or operator may use an alternative 3-point measurement line, locating the three points at 4.4, 14.6, and 29.6 percent of the way across the stack, in accordance with Method 1 in appendix A to part 60 of this chapter.

(3) At locations where stratification is likely to occur (e.g., following a wet scrubber or when dissimilar gas streams are combined), the short measurement line from section 3.2 of PS No. 2 (or the alternative line described in paragraph (b)(2) of this section) may be used in lieu of the prescribed ''long'' measurement line in section 3.2 of PS No. 2, provided that the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed one time at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix) and provided that either the 12-point stratification test or the alternative (abbreviated) stratification test in section 6.5.6.2 of this appendix is performed and passed prior to each subsequent RATA at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix).

(4) A single reference method measurement point, located no less than 1.0 meter from the stack wall and situated along one of the measurement lines used for the stratification test, may be used at any sampling location if

the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed prior to each RATA at the location (according to the acceptance criteria of section 6.5.6.3(b) of this appendix).

6.5.6.1 Stratification Test

(a) With the unit(s) operating under steady-state conditions at normal load, as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO_2 or NO_X) and diluent (CO_2 or O_2) concentrations at a minimum of twelve (12) points, located according to Method 1 in appendix A to part 60 of this chapter.

(b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.

(c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 2-hour period.

(d) If the load has remained constant (±3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.

(e) Calculate the average NO_X, SO_2, and CO_2 (or O_2) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_X, SO_2, and CO_2 (or O_2) concentrations for all traverse points.

6.5.6.2 Alternative (Abbreviated) Stratification Test

(a) With the unit(s) operating under steady-state conditions at normal load, as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO_2 or NO_X) and diluent (CO_2 or O_2) concentrations at three points. The points shall be located according to the specifications for the long measurement line in section 3.2 of PS No. 2 (i.e., locate the points 16.7 percent, 50.0 percent, and 83.3 percent of the way across the stack). Alternatively, the concentration measurements may be made at six traverse points along a diameter. The six points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.

(b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.

(c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 1-hour period.

(d) If the load has remained constant (±3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.

(e) Calculate the average NO_X, SO_2, and CO_2 (or O_2) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_X, SO_2, and CO_2 (or O_2) concentrations for all traverse points.

6.5.6.3 Stratification Test Results and Acceptance Criteria

(a) For each pollutant or diluent gas, the short reference method measurement line described in section 3.2 of PS No. 2 may be used in lieu of the long measurement line prescribed in section 3.2 of PS No. 2 if the results of a stratification test, conducted in accordance with section 6.5.6.1 or 6.5.6.2 of this appendix (as appropriate; see section 6.5.6(b)(3) of this appendix), show that the concentration at each individual traverse point differs by no more than ±10.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ± 5ppm or ±0.5 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points.

(b) For each pollutant or diluent gas, a single reference method measurement point, located at least 1.0 meter from the stack wall and situated along one of the measurement lines used for the stratification test, may be used for that pollutant or diluent gas if the results of a stratification test, conducted in accordance with section 6.5.6.1 of this appendix, show that the concentration at each individual traverse point differs by no more than ±5.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ±3 ppm or ±0.3 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points.

(c) The owner or operator shall keep the results of all stratification tests on-site, in a format suitable for inspection, as part of the supplementary RATA records required under § 75.56(a)(7) or § 75.59(a)(7), as applicable.

6.5.7 Sampling Strategy

(a) Conduct the reference method tests so they will yield results representative of the pollutant concentration, emission rate, moisture, temperature, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, CO_2 or O_2 monitor, flow monitor, and SO_2 or NO_X continuous emission monitoring system measurements. The minimum acceptable time for a gas monitoring system RATA run or for a moisture monitoring system RATA run is 21 minutes. For each run of a gas monitoring system RATA, all necessary pollutant concentration measurements, diluent concentration measurements, and moisture measurements (if applicable) must, to the extent practicable, be made within a 60-minute period. For NO_X-diluent or SO_2-diluent monitoring system RATAs, the pollutant and diluent concentration measurements must be made simultaneously. For flow monitor RATAs, the minimum time per run shall be 5 minutes. Flow rate reference method measurements may be made either sequentially from port to port or simultaneously at two or more sample ports. The velocity measurement probe may be moved from traverse point to traverse point either manually or automatically. If, during a flow RATA, significant pulsations in the reference method readings are observed, be sure to allow enough measurement time at each traverse point to obtain an accurate average reading when a manual readout method is used (e.g., a ''sight-weighted'' average from a manometer). A minimum of one set of auxiliary measurements for stack gas molecular weight determination (i.e., diluent gas data and moisture data) is required for every clock hour of a flow RATA or for every three test runs (whichever is less restrictive). Successive flow RATA runs may be performed without waiting in-between runs. If an O_2-diluent monitor is used as a CO_2 continuous emission monitoring system, perform a CO_2 system RATA (i.e., measure CO_2, rather than O_2, with the reference method). For moisture monitoring systems, an appropriate coefficient, ''K'' factor or other suitable mathematical algorithm may be developed prior to the RATA, to adjust the monitoring system readings with respect to the reference method. If such a coefficient, K-factor or algorithm is developed, it shall be applied to the CEMS readings during the RATA and (if the RATA is passed), to the subsequent CEMS data, by means of the automated data acquisition and handling system. The owner or operator shall keep records of the current coefficient, K factor or algorithm, as specified in §§ 75.56(a)(5)(ix) and 75.59(a)(5)(vii). Whenever the coefficient, K factor or algorithm is changed, a RATA of the moisture monitoring system is required.

(b) To properly correlate individual SO_2 or NO_X continuous emission monitoring system data (in lb/mmBtu) and volumetric flow rate data with the reference method data, annotate the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

* * * * *

6.5.9 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required (i.e., certification, recertification, diagnostic, semiannual, or annual) relative accuracy test audit. For 2-level and 3-level relative accuracy test audits of flow monitors, perform a minimum of nine sets at each of the operating levels.

Note: The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results, as long as the total number of test results used to determine the relative accuracy or bias is greater than or equal to nine. Report all data, including the rejected CEMS data and corresponding reference method test results.

6.5.10 Reference Methods

The following methods from appendix A to part 60 of this chapter or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 or its allowable alternatives in appendix A to part 60 of this chapter (except for Methods 2B and 2E) for stack gas velocity and volumetric flow rate; Methods 3, 3A, or 3B for O_2 or CO_2; Method 4 for moisture; Methods 6, 6A, or 6C for SO_2; Methods 7, 7A, 7C, 7D or 7E for NO_X, excluding the exception in section 5.1.2 of Method 7E. When using Method 7E for measuring NO_X concentration, total NO_X, both NO and NO_2, must be measured.

59. Appendix A to part 75 is amended by revising in sections 7.2.1, and 7.2.2, the text following each section's equation, beginning with the word ''where''; by revising sections 7.6, 7.6.4, and 7.6.5 and by adding new sections 7.7 and 7.8 (without revising the Figures for Appendix A that appear at the end of section 7 to Appendix A) to read as follows:

7. Calculations

* * * * *

7.2.1 Pollutant Concentration and Diluent Monitors

* * * * *

Where:

CE = Calibration error as a percentage of the span of the instrument.

R = Reference value of zero or upscale (high-level or mid-level, as applicable) calibration gas introduced into the monitoring system.

A = Actual monitoring system response to the calibration gas.

S = Span of the instrument, as specified in section 2 of this appendix.

7.2.2 Flow Monitor Calibration Error

* * * * *

Where:

CE = Calibration error as a percentage of span.

R = Low or high level reference value specified in section 2.2.2.1 of this appendix.

A = Actual flow monitor response to the reference value.

S = Flow monitor calibration span value as determined under section 2.1.4.2 of this appendix.

* * * * *

7.6 Bias Test and Adjustment Factor

Test the following relative accuracy test audit data sets for bias: SO_2 pollutant concentration monitors; flow monitors; NO_X concentration monitoring systems used to determine NO_X mass emissions, as defined in § 75.71(a)(2); and NO_X-diluent continuous emission monitoring systems, using the procedures outlined in section 7.6.1 through 7.6.5 of this appendix. For multiple-load flow RATAs, perform a bias test at each load level designated as normal under section 6.5.2.1 of this appendix.

* * * * *

7.6.4 Bias Test

If, for the relative accuracy test audit data set being tested, the mean difference, $\bar{d}$, is less than or equal to the absolute value of the confidence coefficient, | cc |, the monitor or monitoring system has passed the bias test. If the mean difference, $\bar{d}$, is greater than the absolute value of the confidence coefficient, | cc |, the monitor or monitoring system has failed to meet the bias test requirement.

7.6.5 Bias Adjustment

(a) If the monitor or monitoring system fails to meet the bias test requirement, adjust the value obtained from the monitor using the following equation:

$$\mathrm{CEM}_i^{\mathrm{Adjusted}} = \mathrm{CEM}_i^{\mathrm{Monitor}} \times \mathrm{BAF} \qquad (\text{Eq. A-11})$$

Where:

$\mathrm{CEM}_i^{\mathrm{Monitor}}$ = Data (measurement) provided by the monitor at time i.

$\mathrm{CEM}_i^{\mathrm{Adjusted}}$ = Data value, adjusted for bias, at time i.

BAF = Bias adjustment factor, defined by:

$$\mathrm{BAF} = 1 + \frac{|\bar{d}|}{\mathrm{CEM}_{avg}} \qquad (\text{Eq. A-12})$$

Where:

BAF = Bias adjustment factor, calculated to the nearest thousandth.

$\bar{d}$ = Arithmetic mean of the difference obtained during the failed bias test using Equation A–7.

CEM_{avg} = Mean of the data values provided by the monitor during the failed bias test.

(b) For single-load RATAs of SO_2 pollutant concentration monitors, NO_X concentration monitoring systems, and NO_X-diluent monitoring systems and for the single-load flow RATAs required or allowed under section 6.5.2 of this appendix and sections 2.3.1.3(b) and 2.3.1.3(c) of appendix B to this part, the appropriate BAF is determined directly from the RATA results at normal load, using Equation A–12. Notwithstanding, when a NO_X concentration CEMS or an SO_2 CEMS or a NO_X-diluent CEMS installed on a low-emitting affected unit (i.e., average SO_2 or NO_X concentration during the RATA ± 250 ppm or average NO_X emission rate ± 0.200 lb/mmBtu) meets the normal 10.0 percent relative accuracy specification (as calculated using Equation A–10) or the alternate relative accuracy specification in section 3.3 of this appendix for low-emitters, but fails the bias test, the BAF may either be determined using Equation A–12, or a default BAF of 1.111 may be used.

(c) For 2-load or 3-load flow RATAs, when only one load level (low, mid or high) has been designated as normal under section 6.5.2.1 of this appendix and the bias test is passed at the normal load level, apply a BAF of 1.000 to the subsequent flow rate data. If the bias test is failed at the normal load level, use Equation A–12 to calculate the normal load BAF and then perform an additional bias test at the second most frequently-used load level, as determined under section 6.5.2.1 of this appendix. If the bias test is passed at this second load level, apply the normal load BAF to the subsequent flow rate data. If the bias test is failed at this second load level, use Equation A–12 to calculate the BAF at the second load level and apply the higher of the two BAFs (either from the normal load level or from the second load level) to the subsequent flow rate data.

(d) For 2-load or 3-load flow RATAs, when two load levels have been designated as normal under section 6.5.2.1 of this appendix and the bias test is passed at both normal load levels, apply a BAF of 1.000 to the subsequent flow rate data. If the bias test is failed at one of the normal load levels but not at the other, use Equation A–12 to calculate the BAF for the normal load level at which the bias test was failed and apply that BAF to the subsequent flow rate data. If the bias test is failed at both designated normal load levels, use Equation A–12 to calculate the BAF at each normal load level and apply the higher of the two BAFs to the subsequent flow rate data.

(e) Each time a RATA is passed and the appropriate bias adjustment factor has been determined, apply the BAF prospectively to all monitoring system data, beginning with the first clock hour following the hour in which the RATA was completed. For a 2-load flow RATA, the ''hour in which the RATA was completed'' refers to the hour in which the testing at both loads was completed; for a 3-load RATA, it refers to the hour in which the testing at all three loads was completed.

(f) Use the bias-adjusted values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the concentration of SO_2, the flow rate, the average NO_X emission rate, the unit heat input, and the calculated mass emissions of SO_2 and CO_2 during the quarter and calendar year, as specified in subpart G of this part. In addition, when using a NO_X concentration monitoring system and a flow monitor to calculate NO_X mass emissions under subpart H of this part, use bias-adjusted values for NO_X concentration and flow rate in the mass emission calculations and use bias-adjusted NO_X concentrations to compute the appropriate substitution values for NO_X concentration in the missing data routines under subpart D of this part.

* * * * *

7.7 Reference Flow-to-Load Ratio or Gross Heat Rate

(a) Except as provided in section 7.8 of this appendix, the owner or operator shall determine R_{ref}, the reference value of the ratio of flow rate to unit load, each time that a passing flow RATA is performed at a load level designated as normal in section 6.5.2.1 of this appendix. The owner or operator shall report the current value of R_{ref} in the electronic quarterly report required under § 75.64 and shall also report the completion date of the associated RATA. If two load levels have been designated as normal under section 6.5.2.1 of this appendix, the owner or operator shall determine a separate R_{ref} value for each of the normal load levels. The requirements of this section shall become effective as of April 1, 2000. The reference flow-to-load ratio shall be calculated as follows:

$$R_{ref} = \frac{Q_{ref}}{L_{avg}} \times 10^{-5} \qquad \text{(Eq. A-13)}$$

Where:

R_{ref} = Reference value of the flow-to-load ratio, from the most recent normal-load flow RATA, scfh/megawatts or scfh/1000 lb/hr of steam.

Q_{ref} = Average stack gas volumetric flow rate measured by the reference method during the normal-load RATA, scfh.

L_{avg} = Average unit load during the normal-load flow RATA, megawatts or 1000 lb/hr of steam.

(b) In Equation A–13, for a common stack, L_{avg} shall be the sum of the operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks (except for a discharge configuration consisting of a main stack and a bypass stack), Q_{ref} will be the sum of the total volumetric flow rates that discharge through all of the stacks. 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) In addition to determining R_{ref} or as an alternative to determining R_{ref}, a reference value of the gross heat rate (GHR) may be determined. In order to use this option, quality assured diluent gas (CO_2 or O_2) must be available for each hour of the most recent normal-load flow RATA. The reference value of the GHR shall be determined as follows:

$$(GHR)_{ref} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000 \qquad \text{(Eq. A-13a)}$$

Where:

$(GHR)_{ref}$ = Reference value of the gross heat rate at the time of the most recent normal-load flow RATA, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_{avg}$ = Average hourly heat input during the normal-load flow RATA, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

L_{avg} = Average unit load during the normal-load flow RATA, megawatts or 1000 lb/hr of steam.

(d) In the calculation of $(\text{Heat Input})_{avg}$, use Q_{ref}, the average volumetric flow rate measured by the reference method during the RATA, and use the average diluent gas concentration measured during the flow RATA.

7.8 Flow-to-Load Test Exemptions

The requirements of this section apply beginning on April 1, 2000. For complex stack configurations (e.g., when the effluent from a unit is divided and discharges through multiple stacks in such a manner that the flow rate in the individual stacks cannot be correlated with unit load), the owner or operator may petition the Administrator under § 75.66 for an exemption from the requirements of section 7.7 of this appendix. The petition must include sufficient information and data to demonstrate that a flow-to-load or gross heat rate evaluation is infeasible for the complex stack configuration.

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

60. Appendix B to part 75 is amended by revising sections 1 and 1.1; adding sections 1.1.1 through 1.1.3; revising section 1.2; adding sections 1.2.1 through 1.2.4; revising section 1.3; adding sections 1.3.1 through 1.3.6; revising section 1.4; adding sections 1.4.1 through 1.4.3; and removing sections 1.5 and 1.6 to read as follows:

1. Quality Assurance/Quality Control Program

Develop and implement a quality assurance/quality control (QA/QC) program for the continuous emission monitoring systems, excepted monitoring systems approved under appendix D or E to this part, and alternative monitoring systems under subpart E of this part, and their components. At a minimum, include in each QA/QC program a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for each of the following activities. Upon request from regulatory authorities, the source shall make all procedures, maintenance records, and ancillary supporting documentation from the manufacturer (e.g., software coefficients and troubleshooting diagrams) available for review during an audit.

1.1 Requirements for All Monitoring Systems

1.1.1 Preventive Maintenance

Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

1.1.2 Recordkeeping and Reporting

Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements in subparts E, F, and G and appendices D and E to this part, as applicable.

1.1.3 Maintenance Records

Keep a record of all testing, maintenance, or repair activities performed on any monitoring system or component in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor's outage period. Additionally, any adjustment that recharacterizes a system's ability to record and report emissions data must be recorded (e.g., changing of flow monitor or moisture monitoring system polynomial coefficients, K factors or mathematical algorithms, changing of temperature and pressure coefficients and dilution ratio settings), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

1.2 Specific Requirements for Continuous Emissions Monitoring Systems

1.2.1 Calibration Error Test and Linearity Check Procedures

Keep a written record of the procedures used for daily calibration error tests and linearity checks (e.g., how gases are to be injected, adjustments of flow rates and pressure, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error or error in linearity, determination of interferences, and when calibration adjustments should be made). Identify any calibration error test and linearity check procedures specific to the continuous emission monitoring system that vary from the procedures in appendix A to this part.

1.2.2 Calibration and Linearity Adjustments

Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors and other factors affecting calibration of each continuous emission monitoring system.

1.2.3 Relative Accuracy Test Audit Procedures

Keep a written record of procedures and details peculiar to the installed continuous emission monitoring systems that are to be used for relative accuracy test audits, such as sampling and analysis methods.

1.2.4 Parametric Monitoring for Units With Add-on Emission Controls

The owner or operator shall keep a written (or electronic) record including a list of operating parameters for the add-on SO_2 or NO_X emission controls, including parameters in § 75.55(b) or § 75.58(b), as applicable, and the range of each operating parameter that indicates the add-on emission controls are operating properly. The owner or operator shall keep a written (or electronic) record of the parametric monitoring data during each SO_X or NO_2 missing data period.

1.3 Specific Requirements for Excepted Systems Approved Under Appendices D and E

1.3.1 Fuel Flowmeter Accuracy Test Procedures

Keep a written record of the specific fuel flowmeter accuracy test procedures. These may include: standard methods or specifications listed in and section 2.1.5.1 of appendix D to this part and incorporated by reference under § 75.6; the procedures of sections 2.1.5.2 or 2.1.7 of appendix D to this part; or other methods approved by the Administrator through the petition process of § 75.66(c).

1.3.2 Transducer or Transmitter Accuracy Test Procedures

Keep a written record of the procedures for testing the accuracy of transducers or transmitters of an orifice-, nozzle-, or venturi-type fuel flowmeter under section 2.1.6 of appendix D to this part. These procedures should include a description of equipment used, steps in testing, and frequency of testing.

1.3.3 Fuel Flowmeter, Transducer, or Transmitter Calibration and Maintenance Records

Keep a record of adjustments, maintenance, or repairs performed on the fuel flowmeter monitoring system. Keep records of the data and results for fuel flowmeter accuracy tests and transducer accuracy tests, consistent with appendix D to this part.

1.3.4 Primary Element Inspection Procedures

Keep a written record of the standard operating procedures for inspection of the primary element (i.e., orifice, venturi, or nozzle) of an orifice-, venturi-, or nozzle-type fuel flowmeter. Examples of the types of information to be included are: what to examine on the primary element; how to identify if there is corrosion sufficient to affect the accuracy of the primary element; and what inspection tools (e.g., baroscope), if any, are used.

1.3.5 Fuel Sampling Method and Sample Retention

Keep a written record of the standard procedures used to perform fuel sampling, either by utility personnel or by fuel supply company personnel. These procedures should specify the portion of the ASTM method used, as incorporated by reference under § 75.6, or other methods approved by the Administrator through the petition process of § 75.66(c). These procedures should describe safeguards for ensuring the availability of an oil sample (e.g., procedure and location for splitting samples, procedure for maintaining sample splits on site, and procedure for transmitting samples to an analytical laboratory). These procedures should identify the ASTM analytical methods used to analyze sulfur content, gross calorific value, and density, as incorporated by reference under § 75.6, or other methods approved by the Administrator through the petition process of § 75.66(c).

1.3.6 Appendix E Monitoring System Quality Assurance Information

Identify the unit manufacturer's recommended range of quality assurance- and quality control-related operating parameters. Keep records of these operating parameters for each hour of unit operation (i.e., fuel combustion). Keep a written record of the procedures used to perform NO_X emission rate testing. Keep a copy of all data and results from the initial and from the most recent NO_X emission rate testing, including the values of quality assurance parameters specified in section 2.3 of appendix E to this part.

1.4 Requirements for Alternative Systems Approved Under Subpart E

1.4.1 Daily Quality Assurance Tests

Explain how the daily assessment procedures specific to the alternative monitoring system are to be performed.

1.4.2 Daily Quality Assurance Test Adjustments

Explain how each component of the alternative monitoring system will be adjusted in response to the results of the daily assessments.

1.4.3 Relative Accuracy Test Audit Procedures

Keep a written record of procedures and details peculiar to the installed alternative monitoring system that are to be used for relative accuracy test audits, such as sampling and analysis methods.

61. Appendix B to part 75 is amended by:

a. Revising the first paragraph of section 2.1.1, revising sections 2.1.3 and 2.1.4; revising paragraph (1) of section 2.1.5.1; revising sections 2.2 through 2.2.3; adding sections 2.2.4 through 2.2.5.3; revising sections 2.3 and 2.3.1; adding sections 2.3.1.1 through 2.3.1.4; revising sections 2.3.2 and 2.3.3; and adding section 2.3.4;

b. Redesignating existing section 2.4 as section 2.5;

c. Adding new section 2.4; and

d. Revising Figures 1 and 2 at the end of appendix B to read as follows:

2. Frequency of Testing

* * * * *

2.1 * * *

2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-basis O_2 analyzers) according to the procedures in section 6.3.1 of appendix A to this part, and perform the daily calibration error test of each flow monitoring system according to the procedure in section 6.3.2 of appendix A to this part.

* * * * *

2.1.3 Additional Calibration Error Tests and Calibration Adjustments

(a) In addition to the daily calibration error tests required under section 2.1.1 of this appendix, a calibration error test of a monitor shall be performed in accordance with section 2.1.1 of this appendix, as follows: whenever a daily calibration error test is failed; whenever a monitoring system is returned to service following repair or corrective maintenance that could affect the monitor's ability to accurately measure and record emissions data; or after making certain calibration adjustments, as described in this section. Except in the case of the routine calibration adjustments described in this section, data from the monitor are considered invalid until the required additional calibration error test has been successfully completed.

(b) Routine calibration adjustments of a monitor are permitted after any successful calibration error test. These routine adjustments shall be made so as to bring the monitor readings as close as practicable to the known tag values of the calibration gases or to the actual value of the flow monitor reference signals. An additional calibration error test is required following routine calibration adjustments where the monitor's calibration has been physically adjusted (e.g., by turning a potentiometer) to verify that the adjustments have been made properly. An additional calibration error test is not required, however, if the routine calibration adjustments are made by means of a mathematical algorithm programmed into the data acquisition and handling system. The EPA recommends that routine calibration adjustments be made, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification in appendix A to this part for the pollutant concentration monitor, CO_2 or O_2 monitor, or flow monitor.

(c) Additional (non-routine) calibration adjustments of a monitor are permitted prior to (but not during) linearity checks and RATAs and at other times, provided that an appropriate technical justification is included in the quality control program required under section 1 of this appendix. The allowable non-routine adjustments are as follows. The owner or operator may physically adjust the calibration of a monitor (e.g., by means of a potentiometer), provided that the post-adjustment zero and upscale responses of the monitor are within the performance specifications of the instrument given in section 3.1 of appendix A to this part. An additional calibration error test is required following such adjustments to verify that the monitor is operating within the performance specifications at both the zero and upscale calibration levels.

2.1.4 Data Validation

(a) An out-of-control period occurs when the calibration error of an SO_2 or NO_X pollutant concentration monitor exceeds 5.0 percent of the span value (or exceeds 10 ppm, for span values <200 ppm), when the calibration error of a CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percent moisture) exceeds 1.0 percent O_2 or CO_2, or when the calibration error of a flow monitor or a moisture sensor exceeds 6.0 percent of the span value, which is twice the applicable specification of appendix A to this part. Notwithstanding, a differential pressure-type flow monitor for which the calibration error exceeds 6.0 percent of the span value shall not be considered out-of-control if $|R - A|$, the absolute value of the difference between the monitor response and the reference value in Equation A–6, is $\leq$0.02 inches of water. The out-of-control period begins upon failure of the calibration error test and ends upon completion of a successful calibration error test. Note, that if a failed calibration, corrective action, and successful calibration error test occur within the same hour, emission data for that hour recorded by the monitor after the successful calibration error test may be used for reporting purposes, provided that two or more valid readings are obtained as required by § 75.10. A NO_X-diluent continuous emission monitoring system is considered out-of-control if the calibration error of either component monitor exceeds twice the applicable performance specification in appendix A to this part. Emission data shall not be reported from an out-of-control monitor.

(b) An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed.

2.1.5 * * *

2.1.5.1 * * *

(1) Data from a monitoring system are invalid, beginning with the first hour following the expiration of a 26-hour data validation period or beginning with the first hour following the expiration of an 8-hour start-up grace period (as provided under section 2.1.5.2 of this appendix), if the required subsequent daily assessment has not been conducted.

* * * * *

2.2 Quarterly Assessments

For each primary and redundant backup monitor or monitoring system, perform the following quarterly assessments. This requirement is applies as of the calendar quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

2.2.1 Linearity Check

Perform a linearity check, in accordance with the procedures in section 6.2 of appendix A to this part, for each primary and redundant backup SO_2 and NO_X pollutant concentration monitor and each primary and redundant backup CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or to continuously monitor moisture) at least once during each QA operating quarter, as defined in § 72.2 of this chapter. For units using both a low and high span value, a linearity check is required only on the range(s) used to record and report emission data during the QA operating quarter. Conduct the linearity checks no less than 30 days apart, to the extent practicable. The data validation procedures in section 2.2.3(e) of this appendix shall be followed.

2.2.2 Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each QA operating quarter. For this test, the unit does not have to be in operation. Conduct the leak checks no less than 30 days apart, to the extent practicable. If a leak check is failed, follow the applicable data validation procedures in section 2.2.3(f) of this appendix.

2.2.3 Data Validation

(a) A linearity check shall not be commenced if the monitoring system is operating out-of-control with respect to any of the daily or semiannual quality assurance assessments required by sections 2.1 and 2.3 of this appendix or with respect to the additional calibration error test requirements in section 2.1.3 of this appendix.

(b) Each required linearity check shall be done according to paragraph (b)(1), (b)(2) or (b)(3) of this section:

(1) The linearity check may be done ''cold,'' i.e., with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitor prior to the test.

(2) The linearity check may be done after performing only the routine or non-routine calibration adjustments described in section 2.1.3 of this appendix at the various calibration gas levels (zero, low, mid or high), but no other corrective maintenance, repair, re-linearization or reprogramming of the monitor. Trial gas injection runs may be performed after the calibration adjustments and additional adjustments within the allowable limits in section 2.1.3 of this appendix may be made prior to the linearity check, as necessary, to optimize the performance of the monitor. The trial gas injections need not be reported, provided that they meet the specification for trial gas injections in § 75.20(b)(3)(vii)(E)(*1*). However, if, for any trial injection, the specification in § 75.20(b)(3)(vii)(E)(*1*) is not met, the trial injection shall be counted as an aborted linearity check.

(3) The linearity check may be done after repair, corrective maintenance or reprogramming of the monitor. In this case, the monitor shall be considered out-of-control from the hour in which the repair, corrective maintenance or reprogramming is commenced until the linearity check has been passed. Alternatively, the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (ix) may be followed upon completion of the necessary repair, corrective maintenance, or reprogramming. If the procedures in § 75.20(b)(3) are used, the words ''quality assurance'' apply instead of the word ''recertification''.

(c) Once a linearity check has been commenced, the test shall be done hands-off. That is, no adjustments of the monitor are permitted during the linearity test period, other than the routine calibration adjustments following daily calibration error tests, as described in section 2.1.3 of this appendix.

(d) If a daily calibration error test is failed during a linearity test period, prior to completing the test, the linearity test must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The linearity test shall not be commenced until the monitor has successfully completed a calibration error test.

(e) An out-of-control period occurs when a linearity test is failed (i.e., when the error in linearity at any of the three concentrations in the quarterly linearity check (or any of the six concentrations, when both ranges of a single analyzer with a dual range are tested) exceeds the applicable specification in section 3.2 of appendix A to this part) or when a linearity test is aborted due to a problem with the monitor or monitoring system. For a NO_X-diluent or SO_2-diluent continuous emission monitoring system, the system is considered out-of-control if either of the component monitors exceeds the applicable specification in section 3.2 of appendix A to this part or if the linearity test of either component is aborted due to a problem with the monitor. The out-of-control period begins with the hour of the failed or aborted linearity check and ends with the hour of completion of a satisfactory linearity check following corrective action and/or monitor repair, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §§ 75.20(b)(3)(vii)(A) and (B). Note that a monitor shall not be considered out-of-control when a linearity test is aborted for a reason unrelated to the monitor's performance (e.g., a forced unit outage).

(f) No more than four successive calendar quarters shall elapse after the quarter in which a linearity check of a monitor or monitoring system (or range of a monitor or monitoring system) was last performed without a subsequent linearity test having been conducted. If a linearity test has not been completed by the end of the fourth calendar quarter since the last linearity test, then the linearity test must be completed within a 168 unit operating hour or stack operating hour ''grace period'' (as provided in section 2.2.4 of this appendix) following the end of the fourth successive elapsed calendar quarter, or data from the CEMS (or range) will become invalid.

(g) An out-of-control period also occurs when a flow monitor sample line leak is detected. The out-of-control period begins with the hour of the failed leak check and ends with the hour of a satisfactory leak check following corrective action.

(h) For each monitoring system, report the results of all completed and partial linearity tests that affect data validation (i.e., all completed, passed linearity checks; all completed, failed linearity checks; and all linearity checks aborted due to a problem with the monitor, including trial gas injections counted as failed test attempts under paragraph (b)(2) of this section or under § 75.20(b)(3)(vii)(F)), in the quarterly report required under § 75.64. Note that linearity attempts which are aborted or invalidated due to problems with the reference calibration gases or due to operational problems with the affected unit(s) need not be reported. Such partial tests do not affect the validation status of emission data recorded by the monitor. A record of all linearity tests, trial gas injections and test attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.

2.2.4 Linearity and Leak Check Grace Period

(a) When a required linearity test or flow monitor leak check has not been completed by the end of the QA operating quarter in which it is due or if, due to infrequent operation of a unit or infrequent use of a required high range of a monitor or monitoring system, four successive calendar quarters have elapsed after the quarter in which a linearity check of a monitor or monitoring system (or range) was last performed without a subsequent linearity test having been done, the owner or operator has a grace period of 168 consecutive unit operating hours, as defined in § 72.2 of this chapter (or, for monitors installed on common stacks or bypass stacks, 168 consecutive stack operating hours, as defined in § 72.2 of this chapter) in which to perform a linearity test or leak check of that monitor or monitoring system (or range). The grace period begins with the first unit or stack operating hour following the calendar quarter in which the linearity test was due. Data validation during a linearity or leak check grace period shall be done in accordance with the applicable provisions in section 2.2.3 of this appendix.

(b) If, at the end of the 168 unit (or stack) operating hour grace period, the required linearity test or leak check has not been completed, data from the monitoring system (or range) shall be invalid, beginning with the hour following the expiration of the grace period. Data from the monitoring system (or range) remain invalid until the hour of completion of a subsequent successful hands-off linearity test or leak check of the monitor or monitoring system (or range). Note that when a linearity test or a leak check is conducted within a grace period for the purpose of satisfying the linearity test or leak check requirement from a previous QA operating quarter, the results of that linearity test or leak check may only be used to meet the linearity check or leak check requirement of the previous quarter, not the quarter in which the missed linearity test or leak check is completed.

2.2.5 Flow-to-Load Ratio or Gross Heat Rate Evaluation

(a) *Applicability and methodology.* The provisions of this section apply beginning on April 1, 2000. Unless exempted by an approved petition in accordance with section 7.8 of appendix A to this part, the owner or operator shall, for each flow rate monitoring system installed on each unit, common stack or multiple stack, evaluate the flow-to-load ratio quarterly, i.e., for each QA operating quarter (as defined in § 72.2 of this chapter). At the end of each QA operating quarter, the owner or operator shall use Equation B–1 to calculate the flow-to-load ratio for every hour during the quarter in which: the unit (or combination of units, for a common stack) operated within ±10.0 percent of L_{avg}, the average load during the most recent normal-load flow RATA; and a quality assured hourly average flow rate was obtained with a certified flow rate monitor.

$$R_h = \frac{Q_h}{L_h} \times 10^{-5} \qquad \text{(Eq. B-1)}$$

Where:

R_h = Hourly value of the flow-to-load ratio, scfh/megawatts or scfh/1000 lb/hr of steam load.

Q_h = Hourly stack gas volumetric flow rate, as measured by the flow rate monitor, scfh.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam; must be within ±10.0 percent of L_{avg} during the most recent normal-load flow RATA.

(1) In Equation B–1, the owner or operator may use either bias-adjusted flow rates or unadjusted flow rates, provided that all of the ratios are calculated the same way. For a common stack, L_h shall be the sum of the hourly operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks (except when one of the stacks is a bypass stack) or that monitors its emissions in multiple breechings, Q_h will be the combined hourly volumetric flow rate for all of the stacks or ducts. For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack, each of which has a certified flow monitor (e.g., a unit with a wet SO_2 scrubber), calculate the hourly flow-to-load ratios separately for each stack. Round off each value of R_h to two decimal places.

(2) Alternatively, the owner or operator may calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. The hourly GHR shall be determined only for those hours in which quality assured flow rate data and diluent gas (CO_2 or O_2) concentration data are both available from a certified monitor or monitoring system or reference method. If this option is selected, calculate each hourly GHR value as follows:

$$(\text{GHR})_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000 \qquad \text{(Eq. B-1a)}$$

where:

$(\text{GHR})_h$ = Hourly value of the gross heat rate, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_h$ = Hourly heat input, as determined from the quality assured flow rate and diluent data, using the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam; must be within ± 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

(3) In Equation B–1a, the owner or operator may either use bias-adjusted flow rates or unadjusted flow rates in the calculation of $(\text{Heat Input})_h$, provided that all of the heat input values are determined in the same manner.

(4) The owner or operator shall evaluate the calculated hourly flow-to-load ratios (or gross heat rates) as follows. A separate data analysis shall be performed for each primary and each redundant backup flow rate monitor used to record and report data during the quarter. Each analysis shall be based on a minimum of 168 recorded hourly average flow rates. When two RATA load levels are designated as normal, the analysis shall be performed at the higher load level, unless there are fewer than 168 data points available at that load level, in which case the analysis shall be performed at the lower load level. If, for a particular flow monitor, fewer than 168 hourly flow-to-load ratios (or GHR values) are available at any of the load levels designated as normal, a flow-to-load (or GHR) evaluation is not required for that monitor for that calendar quarter.

(5) For each flow monitor, use Equation B–2 in this appendix to calculate E_h, the absolute percentage difference between each hourly R_h value and R_{ref}, the reference value of the flow-to-load ratio, as determined in accordance with section 7.7 of appendix A to this part. Note that R_{ref} shall always be based upon the most recent normal-load RATA, even if that RATA was performed in the calendar quarter being evaluated.

$$E_h = \frac{|R_{ref} - R_h|}{R_{ref}} \times 100 \qquad \text{(Eq. B-2)}$$

where:

E_h = Absolute percentage difference between the hourly average flow-to-load ratio and the reference value of the flow-to-load ratio at normal load.

R_h = The hourly average flow-to-load ratio, for each flow rate recorded at a load level within $\pm$ 10.0 percent of L_{avg}.

R_{ref} = The reference value of the flow-to-load ratio from the most recent normal-load flow RATA, determined in accordance with section 7.7 of appendix A to this part.

(6) Equation B–2 shall be used in a consistent manner. That is, use R_{ref} and R_h if the flow-to-load ratio is being evaluated, and use $(GHR)_{ref}$ and $(GHR)_h$ if the gross heat rate is being evaluated. Finally, calculate E_f, the arithmetic average of all of the hourly E_h values. The owner or operator shall report the results of each quarterly flow-to-load (or gross heat rate) evaluation, as determined from Equation B–2, in the electronic quarterly report required under § 75.64.

(b) *Acceptable results.* The results of a quarterly flow-to-load (or gross heat rate) evaluation are acceptable, and no further action is required, if the calculated value of E_f is less than or equal to: (1) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥60 megawatts (or ≥500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or (2) 10.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥60 megawatts (or ≥500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations; or (3) 20.0 percent, if L_{avg} for the most recent normal-load flow RATA is <60 megawatts (or <500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or (4) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is <60 megawatts (or <500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations. 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; or perform a RATA in accordance with Option 2 in section 2.2.5.2 of this appendix; or 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.

(c) *Recalculation of E_f.* If the owner or operator 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) Any hour in which the type of fuel combusted was different from the fuel burned during the most recent normal-load RATA. For purposes of this determination, the type of fuel is different if the fuel is in a different state of matter (i.e., solid, liquid, or gas) than is the fuel burned during the RATA or if the fuel is a different classification of coal (e.g., bituminous versus sub-bituminous);

(2) For a unit that is equipped with an SO_2 scrubber and which always discharges its flue gases to the atmosphere through a single stack, any hour in which the SO_2 scrubber was bypassed;

(3) Any hour in which ''ramping'' occurred, i.e., the hourly load differed by more than ±15.0 percent from the load during the preceding hour or the subsequent hour;

(4) For a unit with a multiple stack discharge configuration consisting of a main stack and a bypass stack, any hour in which the flue gases were discharged through both stacks;

(5) If a normal-load flow RATA was performed and passed during the quarter being analyzed, any hour prior to completion of that RATA; and

(6) If a problem with the accuracy of the flow monitor was discovered during the quarter and was corrected (as evidenced by passing the abbreviated flow-to-load test in section 2.2.5.3 of this appendix), any hour prior to completion of the abbreviated flow-to-load test.

(7) After identifying and excluding all non-representative hourly data in accordance with paragraphs (c)(1) through (6) of this section, the owner or operator may analyze the remaining data a second time. At least 168 representative hourly ratios or GHR values must be available to perform the analysis; otherwise, the flow-to-load (or GHR) analysis is not required for that monitor for that calendar quarter.

(8) If, after re-analyzing the data, E_f meets the applicable limit in paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section, no further action is required. If, however, E_f is still above the applicable limit, the monitor shall be declared out-of-control, beginning with the first hour of the quarter following the quarter in which E_f exceeded the applicable limit. The owner or operator shall then either implement Option 1 in section 2.2.5.1 of this appendix or Option 2 in section 2.2.5.2 of this appendix.

2.2.5.1 Option 1

Within two weeks of the end of the calendar quarter for which the E_f value is above the applicable limit, investigate and troubleshoot the applicable flow monitor(s). Evaluate the results of each investigation as follows:

(a) If the investigation fails to uncover a problem with the flow monitor, a RATA shall be performed in accordance with Option 2 in section 2.2.5.2 of this appendix.

(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)), 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. Data from the monitor shall remain invalid until a probationary calibration error test of the monitor is passed following completion of all corrective actions, at which point data from the monitor are conditionally valid. The owner or operator then either may 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-level 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. Data from the monitor remain invalid until the required RATA has been passed.

2.2.5.3 Abbreviated Flow-to-Load Test

(a) The following abbreviated flow-to-load test may be performed after any documented repair, component replacement, or other corrective maintenance to a flow monitor (except for changes affecting the linearity of the flow monitor, such as adjusting the flow monitor coefficients or K factor(s)) to demonstrate that the repair, replacement, or other maintenance has not significantly affected the monitor's ability to accurately measure the stack gas volumetric flow rate. Data from the monitoring system are considered invalid from the hour of commencement of the repair, replacement, or maintenance until the hour in which a probationary calibration error test is passed following completion of the repair, replacement, or maintenance and any associated adjustments to the monitor. The abbreviated flow-to-load test shall be completed within 168 unit operating hours of the probationary calibration error test (or, for peaking units, within 30 unit operating days, if that is less restrictive). Data from the monitor are considered to be conditionally valid (as defined in § 72.2 of this chapter), beginning with the hour of the probationary calibration error test.

(b) Operate the unit(s) in such a way as to reproduce, as closely as practicable, the exact conditions at the time of the most recent normal-load flow RATA. To achieve this, it is recommended that the load be held constant to within ±5.0 percent of the average load during the RATA and that the diluent gas (CO_2 or O_2) concentration be maintained within ±0.5 percent CO_2 or O_2 of the average diluent concentration during the RATA. For common stacks, to the extent practicable, use the same combination of units and load levels that were used during the RATA. When the process parameters have been set, record a minimum of six and a maximum of 12 consecutive hourly average flow rates, using the flow monitor(s) for which E_f was outside the applicable limit. For peaking units, a minimum of three and a maximum of 12 consecutive hourly average flow rates are required. Also record the corresponding hourly load values and, if applicable, the hourly diluent gas concentrations. Calculate the flow-to-load ratio (or GHR) for each hour in the test hour period, using Equation B–1 or B–1a. Determine E_h for each hourly flow-to-load ratio (or GHR), using Equation B–2 of this appendix and then calculate E_f, the arithmetic average of the E_h values.

(c) The results of the abbreviated flow-to-load test shall be considered acceptable, and no further action is required if the value of E_f does not exceed the applicable limit specified in section 2.2.5 of this appendix. All conditionally valid data recorded by the flow monitor shall be considered quality assured, beginning with the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test. However, if E_f is outside the applicable limit, all conditionally valid data recorded by the flow monitor shall be considered invalid back to the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test, and a single-load RATA is required in accordance with section 2.2.5.2 of this appendix. If the flow monitor must be re-linearized, however, a 3-load RATA is required.

2.3 Semiannual and Annual Assessments

For each primary and redundant backup monitoring system, perform relative accuracy assessments either semiannually or annually, as specified in section 2.3.1.1 or 2.3.1.2 of this appendix, for the type of test and the performance achieved. This requirement applies as of the calendar quarter following the calendar quarter in which the monitoring system is provisionally certified. A summary chart showing the frequency with which a relative accuracy test audit must be performed, depending on the accuracy achieved, is located at the end of this appendix in Figure 2.

2.3.1 Relative Accuracy Test Audit (RATA)

2.3.1.1 Standard RATA Frequencies

(a) Except as otherwise specified in § 75.21(a)(6) or (a)(7) or in section 2.3.1.2 of this appendix, perform relative accuracy test audits semiannually, i.e., once every two successive QA operating quarters (as defined in § 72.2 of this chapter) for each primary and redundant backup SO_2 pollutant concentration monitor, flow monitor, CO_2 pollutant concentration monitor (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitor used to determine heat input, moisture monitoring system, NO_X concentration monitoring system, NO_X-diluent continuous emission monitoring system, or SO_2-diluent continuous emission monitoring system. A calendar quarter that does not qualify as a QA operating quarter shall be excluded in determining the deadline for the next RATA. No more than eight successive calendar quarters shall elapse after the quarter in which a RATA was last performed without a subsequent RATA having been conducted. If a RATA has not been completed by the end of the eighth calendar quarter since the quarter of the last RATA, then the RATA must be completed within a 720 unit (or stack) operating hour grace period (as provided in section 2.3.3 of this appendix) following the end of the eighth successive elapsed calendar quarter, or data from the CEMS will become invalid.

(b) The relative accuracy test audit frequency of a CEMS may be reduced, as specified in section 2.3.1.2 of this appendix, for primary or redundant backup monitoring systems which qualify for less frequent testing. Perform all required RATAs in accordance with the applicable procedures and provisions in sections 6.5 through 6.5.2.2 of appendix A to this part and sections 2.3.1.3 and 2.3.1.4 of this appendix.

2.3.1.2 Reduced RATA Frequencies

Relative accuracy test audits of primary and redundant backup SO_2 pollutant concentration monitors, CO_2 pollutant concentration monitors (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitors used to determine heat input, moisture monitoring systems, NO_X concentration monitoring systems, flow monitors, NO_X-diluent monitoring systems or SO_2-diluent monitoring systems may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved:

(a) The relative accuracy during the audit of an SO_2 or CO_2 pollutant concentration monitor (including an O_2 pollutant monitor used to measure CO_2 using the procedures in appendix F to this part), or of a CO_2 or O_2 diluent monitor used to determine heat input, or of a NO_X concentration monitoring system, or of a NO_X-diluent monitoring system, or of an SO_2-diluent continuous emissions monitoring system is ≤ 7.5 percent;

(b) Prior to January 1, 2000, the relative accuracy during the audit of a flow monitor is ≤ 10.0 percent at each operating level tested;

(c) On and after January 1, 2000, the relative accuracy during the audit of a flow monitor is ≤ 7.5 percent at each operating level tested;

(d) For low flow (≤ 10.0 fps) stacks/ducts, when the flow monitor fails to achieve a relative accuracy ≤ 7.5 percent (10.0 percent if prior to January 1, 2000) during the audit, but the monitor mean value, calculated using Equation A–7 in appendix A to this part and converted back to an equivalent velocity in standard feet per second (fps), is within ± 1.5 fps of the reference method mean value, converted to an equivalent velocity in fps;

(e) For low SO_2 or NO_X emitting units (average SO_2 or NO_X concentrations ≤ 250 ppm, when an SO_2 pollutant concentration monitor or NO_X concentration monitoring system fails to achieve a relative accuracy ≤ 7.5 percent during the audit, but the monitor mean value from the RATA is within ± 12 ppm of the reference method mean value;

(f) For units with low NO_X emission rates (average NO_X emission rate ≤ 0.200 lb/mmBtu), when a NO_X-diluent continuous emission monitoring system fails to achieve a relative accuracy ≤ 7.5 percent, but the monitoring system mean value from the RATA, calculated using Equation A–7 in appendix A to this part, is within ± 0.015 lb/mmBtu of the reference method mean value;

(g) For units with low SO_2 emission rates (average SO_2 emission rate ≤ 0.500 lb/mmBtu), when an SO_2-diluent continuous emission monitoring system fails to achieve a relative accuracy ≤ 7.5 percent, but the monitoring system mean value from the RATA, calculated using Equation A–7 in appendix A to this part, is within ± 0.025 lb/mmBtu of the reference method mean value;

(h) For a CO_2 or O_2 monitor, when the mean difference between the reference method values from the RATA and the corresponding monitor values is within ± 0.7 percent CO_2 or O_2; and

(i) When the relative accuracy of a continuous moisture monitoring system is ≤ 7.5 percent or when the mean difference between the reference method values from the RATA and the corresponding monitoring system values is within ± 1.0 percent H_2O.

2.3.1.3 RATA Load Levels and Additional RATA Requirements

(a) For SO_2 pollutant concentration monitors, CO_2 pollutant concentration monitors (including O_2 monitors used to determine CO_2 emissions), CO_2 or O_2 diluent monitors used to determine heat input, NO_X concentration monitoring systems, moisture monitoring systems, SO_2-diluent monitoring systems and NO_X-diluent monitoring systems, the required semiannual or annual RATA tests shall be done at the load level designated as normal under section 6.5.2.1 of appendix A to this part. If two load levels are designated as normal, the required RATA(s) may be done at either load level.

(b) For flow monitors installed on peaking units and bypass stacks, all required semiannual or annual relative accuracy test audits shall be single-load audits at the normal load, as defined in section 6.5.2.1 of appendix A to this part.

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

(1) An annual 2-load flow RATA shall be done at the two most frequently used load levels, as determined under section 6.5.2.1 of appendix A to this part.

(2) If the flow monitor is on a semiannual RATA frequency, 2-load flow RATAs and single-load flow RATAs at normal load may be performed alternately.

(3) A single-load annual flow RATA, at the most frequently used load level, may be performed in lieu of the 2-load 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 7 days prior to the date of the current annual flow RATA, the unit has operated at a single load level (low, mid or high) for ≥ 85.0 percent of the time. * * *

(4) A 3-load RATA, at the low-, mid-, and high-load levels, determined under section 6.5.2.1 of appendix A to this part, shall be performed at least once in every period of five consecutive calendar years.

(5) A 3-load RATA is required whenever a flow monitor is re-linearized, i.e., when its polynomial coefficients or K factor(s) are changed.

(6) For all multi-level flow audits, the audit points at adjacent load 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.

(d) A RATA of a moisture monitoring system shall be performed whenever the coefficient, K factor or mathematical algorithm determined under section 6.5.7 of appendix A to this part is changed.

2.3.1.4 Number of RATA Attempts

The owner or operator may perform as many RATA attempts as are necessary to achieve the desired relative accuracy test audit frequencies and/or bias adjustment factors. However, the data validation procedures in section 2.3.2 of this appendix must be followed.

2.3.2 Data Validation

(a) A RATA shall not commence if the monitoring system is operating out-of-control with respect to any of the daily and quarterly quality assurance assessments required by sections 2.1 and 2.2 of this appendix or with respect to the additional calibration error test requirements in section 2.1.3 of this appendix.

(b) Each required RATA shall be done according to paragraphs (b)(1), (b)(2) or (b)(3) of this section:

(1) The RATA may be done ''cold,'' i.e., with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitoring system prior to the test.

(2) The RATA may be done after performing only the routine or non-routine calibration adjustments described in section 2.1.3 of this appendix at the zero and/or upscale calibration gas levels, but no other corrective maintenance, repair, re-linearization or reprogramming of the monitoring system. Trial RATA runs may be performed after the calibration adjustments and additional adjustments within the allowable limits in section 2.1.3 of this appendix may be made prior to the RATA, as necessary, to optimize the performance of the CEMS. The trial RATA runs need not be reported, provided that they meet the specification for trial RATA runs in § 75.20(b)(3)(vii)(E)(*2*). However, if, for any trial run, the specification in § 75.20(b)(3)(vii)(E)(*2*) is not met, the trial run shall be counted as an aborted RATA attempt.

(3) The RATA may be done after repair, corrective maintenance, re-linearization or reprogramming of the monitoring system. In this case, the monitoring system shall be considered out-of-control from the hour in which the repair, corrective maintenance, re-linearization or reprogramming is commenced until the RATA has been passed. Alternatively, the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (ix) may be followed upon completion of the necessary repair, corrective maintenance, re-linearization or reprogramming. If the procedures in § 75.20(b)(3) are used, the words ''quality assurance'' apply instead of the word ''recertification.''

(c) Once a RATA is commenced, the test must be done hands-off. No adjustment of the monitor's calibration is permitted during the RATA test period, other than the routine calibration adjustments following daily calibration error tests, as described in section 2.1.3 of this appendix. For 2-level and 3-level flow monitor audits, no linearization or reprogramming of the monitor is permitted in between load levels.

(d) For single-load RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The subsequent RATA shall not be commenced until the monitor has successfully passed a calibration error test in accordance with section 2.1.3 of this appendix. For multiple-load flow RATAs, each load level is treated as a separate RATA (i.e., when a calibration error test is failed prior to completing the RATA at a particular load level, only the RATA at that load level must be repeated; the results of any previously-passed RATA(s) at the other load level(s) are unaffected, unless re-linearization of the monitor is required to correct the problem that caused the calibration failure, in which case a subsequent 3-load RATA is required).

(e) If a 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, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B). Note that a monitoring system shall not be considered out-of-control when a RATA is aborted for a reason other than monitoring system malfunction (see paragraph (h) of this section).

(f) For a 2-level or 3-level flow RATA, if, at any load level, a RATA is failed or aborted due to a problem with the flow monitor, the RATA at that load level must be repeated. The flow monitor is considered out-of-control and data from the monitor are invalidated from the hour in which the test is failed or aborted and remain invalid until the passing of a RATA at the failed load level, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in § 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with § 75.20(b)(3)(vii)(A) and (B). Flow RATA(s) that were previously passed at the other load level(s) do not have to be repeated unless the flow monitor must be re-linearized following the failed or aborted test. If the flow monitor is re-linearized, a subsequent 3-load RATA is required.

(g) For a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) which also serves as the diluent component in a NO_X-diluent (or SO_2-diluent) monitoring system, if the CO_2 (or O_2) RATA is failed, then both the CO_2 (or O_2) monitor and the associated NO_X-diluent (or SO_2-diluent) system are considered out-of-control, beginning with the hour of completion of the failed CO_2 (or O_2) monitor RATA, and continuing until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of appendix A to this part, unless the option in paragraph (b)(3) of this section to use the data validation procedures and associated timelines in §§ 75.20(b)(3)(ii) through (b)(3)(ix) has been selected, in which case the beginning and end of the out-of-control period shall be determined in accordance with §§ 75.20(b)(3)(vii) (A) and (B).

(h) For each monitoring system, report the results of all completed and partial RATAs that affect data validation (i.e., all completed, passed RATAs; all completed, failed RATAs; and all RATAs aborted due to a problem with the CEMS, including trial RATA runs counted as failed test attempts under paragraph (b)(2) of this section or under § 75.20(b)(3)(vii)(F)) in the quarterly report required under § 75.64. Note that RATA attempts that are aborted or invalidated due to problems with the reference method or due to operational problems with the affected unit(s) need not be reported. Such runs do not affect the validation status of emission data recorded by the CEMS. However, a record of all RATAs, trial RATA runs and RATA attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.

(i) Each time that a hands-off RATA of an SO_2 pollutant concentration monitor, a NO_X-diluent monitoring system, a NO_X concentration monitoring system or a flow monitor is passed, perform a bias test in accordance with section 7.6.4 of appendix A to this part. Apply the appropriate bias adjustment factor to the reported SO_2, NO_X, or flow rate data, in accordance with section 7.6.5 of appendix A to this part.

(j) Failure of the bias test does not result in the monitoring system being out-of-control.

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: a required RATA has not been performed by the end of the QA operating quarter in which it is due; or five consecutive calendar years have elapsed without a required 3-load flow RATA having been conducted; or 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 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.

(b) Except for SO_2 monitoring system RATAs, the grace period shall begin with the first unit (or stack) operating hour following the calendar quarter in which the required RATA was due. For SO_2 monitor RATAs, the grace period shall begin with the first unit (or stack) operating hour in which fuel with a total sulfur content higher than that of very low sulfur fuel (as defined in § 72.2 of this chapter) is burned in the unit(s), following the quarter in which the required RATA is due. Data validation during a RATA grace period shall be done in accordance with the applicable provisions in section 2.3.2 of this appendix.

(c) If, at the end of the 720 unit (or stack) operating hour grace period, the RATA has not been completed, data from the monitoring system shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the CEMS remain invalid until the hour of completion of a subsequent hands-off RATA. Note that when a RATA (or RATAs, if more than one attempt is made) is done during a grace period in order to satisfy a RATA requirement from a previous quarter, the deadline for the next RATA shall be determined from the quarter in which the RATA was due, not from the quarter in which the RATA is actually completed. However, if a RATA deadline determined in this manner is less than two QA operating quarters from the quarter in which the missed RATA is completed , the RATA deadline shall be re-set at two QA operating quarters from the quarter in which the missed RATA is completed .

2.3.4 Bias Adjustment Factor

Except as otherwise specified in section 7.6.5 of appendix A to this part, if an SO_2 pollutant concentration monitor, flow monitor, NO_X continuous emission monitoring system, or NO_X concentration monitoring system used to calculate NO_X mass emissions fails the bias test specified in section 7.6 of appendix A to this part, use the bias adjustment factor given in Equations A–11 and A–12 of appendix A to this part to adjust the monitored data.

2.4 Recertification, Quality Assurance, RATA Frequency and Bias Adjustment Factors (Special Considerations)

(a) When a significant change is made to a monitoring system such that recertification of the monitoring system is required in accordance with § 75.20(b), a recertification test (or tests) must be performed to ensure that the CEMS continues to generate valid data. In all recertifications, a RATA will be one of the required tests; for some recertifications, other tests will also be required. A recertification test may be used to satisfy the quality assurance test requirement of this appendix. For example, if, for a particular change made to a CEMS, one of the required recertification tests is a linearity check and the linearity check is successful, then, unless another such recertification event occurs in that same QA operating quarter, it would not be necessary to perform an additional linearity test of the CEMS in that quarter to meet the quality assurance requirement of section 2.2.1 of this appendix. For this reason, EPA recommends that owners or operators coordinate component replacements, system upgrades, and other events that may require recertification, to the extent practicable, with the periodic quality assurance testing required by this appendix. When a quality assurance test is done for the dual purpose of recertification and routine quality assurance, the applicable data validation procedures in § 75.20(b)(3) shall be followed.

(b) Except as provided in section 2.3.3 of this appendix, whenever a passing RATA of a gas monitor or a passing 2-load or 3-load 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 and 3-load flow RATAs, use the highest percentage relative accuracy at any of the loads to determine the RATA frequency. The results of a single-load flow RATA may be used to establish the RATA frequency when the single-load flow RATA is specifically required under section 2.3.1.3(b) of this appendix (for flow monitors installed on peaking units and bypass stacks) or when the single-load RATA is allowed under section 2.3.1.3(c) of this appendix for a unit that has operated at the most frequently used load level for ≥85.0 percent of the time since the last annual flow RATA. No other single-load flow RATA may be used to establish an annual RATA frequency; however, a 2-load or 3-load flow RATA may be performed at any time or in place of any required single-load RATA, in order to establish an annual RATA frequency.

2.5 Other Audits

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FIGURE 1 TO APPENDIX B OF PART 75—Quality Assurance Test Requirements.

Test	QA test frequency requirements		
	Daily*	Quarterly*	Semiannual*
Calibration Error (2 pt.)			
Interference (flow)			
Flow-to-Load Ratio			
Leak Check (DP flow monitors)			
Linearity (3 pt.)			
RATA (SO_2, NO_X, CO_2, H_2O)[1]			
RATA (flow)[1,2]			

-For monitors on bypass stack/duct, ''daily'' means bypass operating days, only. ''Quarterly'' means once every QA operating quarter. ''Semi-annual'' means once every two QA operating quarters.

[1] Conduct RATA annually (i.e., once every four QA operating quarters), if monitor meets accuracy requirements to qualify for less frequent testing.

[2] For flow monitors installed on peaking units and bypass stacks, conduct all RATAs at a single, normal load. For other flow monitors, conduct annual RATAs at the two load levels used most frequently since the last annual RATA. Alternating single-load and 2-load RATAs may be done if a monitor is on a semiannual frequency. A single-load RATA may be done in lieu of a 2-load RATA if, since the last annual flow RATA, the unit has operated at one load level for ≥85.0 percent of the time. A 3-load RATA is required at least once in every period of five consecutive calendar years and whenever a flow monitor is re-linearized.

FIGURE 2 TO APPENDIX B OF PART 75—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM .

RATA	Semiannual[1] (percent)	Annual[1]
SO_2 or NO_X[3]	7.5% <RA ≤ 10.0% or ± 15.0 ppm[2]	RA ≤ 7.5% or ± 12.0 ppm[2]
SO_2-diluent	7.5% < RA ≤ 10.0% or ± 0.030 lb/mmBtu[2]	RA ≤ 7.5% or ± 0.025. lb/mmBtu[2]
NO_X-diluent	7.5% < RA ≤ 10.0% or ± 0.020	RA ≤ 7.5% or ± 0.015.

FIGURE 2 TO APPENDIX B OF PART 75—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM .—Continued

RATA	Semiannual [1] (percent)	Annual [1]
	lb/mmBtu [2]	lb/mmBtu [2].
Flow (Phase I)	10.0% < RA ≤ 15.0% or ± 1.5 fps [2]	RA ≤ 10.0%.
Flow (Phase II)	7.5% < RA ≤ 10.0% or ± 1.5 fps [2]	RA ≤ 7.5%.
CO_2 or O_2	7.5% < RA ≤ 10.0% or ± 1.0% CO_2/O_2[2]	RA ≤ 7.5% or ± 0.7% CO_2/O_2[2].
Moisture	7.5% < RA ≤ 10.0% or ± 1.5% H_2O_2	RA ≤ 7.5% or ± 1.0% H_2O^2.

[1] The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters with fewer than 168 unit operating hours (or, for common stacks and bypass stacks, exclude quarters with fewer than 168 stack operating hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only very low sulfur fuel as defined in § 72.2, is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.

[2] The difference between monitor and reference method mean values applies to moisture monitors, CO_2, and O_2 monitors, low emitters, or low flow, only.

[3] A NO_X concentration monitoring system used to determine NO_2 mass emissions under § 75.71.

Appendix C To Part 75—Missing Data Statistical Estimation Procedures

62.–63. Appendix C to part 75 is amended by revising sections 2.1, 2.2.1, 2.2.2, 2.2.3, and 2.2.5, and by revising section 2.2.3.9 to read as follows:

2. Load-Based Procedure for Missing Flow Rate and NO_X Emission Rate Data

2.1 Applicability

This procedure is applicable for data from all affected units for use 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 NOx concentration monitoring systems used to determine NO_X mass emissions.

2.2 * * *

2.2.1 For a single unit, establish ten operating load ranges defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MWge), as shown in Table C–1. (Do not use integrated hourly gross load in MW-hr.) For units sharing a common stack monitored with a single flow monitor, the load ranges for flow (but not for NO_X) may be broken down into 20 operating load ranges in increments of 5.0 percent of the combined maximum hourly average gross load of all units utilizing the common stack. If this option is selected, the twentieth (uppermost) operating load range shall include all values greater than 95.0 percent of the maximum hourly average gross load. For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity or for a unit for which hourly average gross load in MWge is not recorded separately, use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia) instead of MWge. Indicate a change in the number of load ranges or the units of loads to be used in the precertification section of the monitoring plan.

TABLE C–1.—DEFINITION OF OPERATING LOAD RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURES

Operating load range	Percent of maximum hourly gross load or maximum hourly gross steam load (percent)
1	0–10
2	>10–20
3	>20–30
4	>30–40
5	>40–50
6	>50–60
7	>60–70
8	>70–80
9	>80–90
10	>90

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_X-diluent continuous emission monitoring system (or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2)), for each hour of unit operation record a number, 1 through 10, (or 1 through 20 for flow at common stacks) that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_X-diluent continuous emission monitoring system (or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2)) and continuing thereafter, the data acquisition and handling system must be capable of calculating and recording the following information for each unit operating hour of missing flow or NO_X data within each identified load range 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.

* * * * *

2.2.3.9 Average of the hourly NO_X pollutant concentrations, in ppm, reported by a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in § 75.71(a)(2).

* * * * *

2.2.5 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 used to determine NO_X mass emissions, as defined in § 75.71(a)(2)), apply the adjustment factor to all monitor or continuous emission monitoring system data values placed in the load ranges.

* * * * *

Appendix D To Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

64. Appendix D to part 75 is amended by revising section 1.1 to read as follows:

1. Applicability

1.1 This protocol may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 mass emissions and heat input from: gas-fired units, as defined in § 72.2 of this chapter, or oil-fired units, as defined in § 72.2 of this chapter. Section 2.1 of this appendix provides procedures for measuring oil or gaseous fuel flow using a fuel flowmeter, section 2.2 of this appendix provides procedures for conducting oil sampling and analysis to determine sulfur content and gross calorific value (GCV) of fuel oil, and section 2.3 of this appendix provides procedures for determining the sulfur content and GCV of gaseous fuels.

* * * * *

65. Appendix D to part 75 is further amended by:

a. Revising sections 2.1 and 2.1.1;
b. Addding sections 2.1.1.1 through 2.1.1.3;
c. Revising sections 2.1.2 through 2.1.4;
d. Adding sections 2.1.4.1 through 2.1.4.3;
e. Revising sections 2.1.5 through 2.1.5.2;
f. Adding sections 2.1.5.3 through 2.1.5.4;
g. Revising sections 2.1.6 through 2.1.6.2;
h. Adding sections 2.1.6.3 through 2.1.7.5;
i. Revising sections 2.2 and 2.2.1;
j. Removing sections 2.2.1.1 and 2.2.1.2;
k. Removing and reserving section 2.2.2;
l. Revising sections 2.2.3 and 2.2.4;
m. Adding sections 2.2.4.1 through 2.2.4.3;

n. Revising the first sentence of section 2.2.6;

o. Revising sections 2.2.8 and 2.3 through 2.3.2.1;

p. Adding sections 2.3.2.1.1 and 2.3.2.1.2;

q. Revising section 2.3.2.2;

r. Adding sections 2.3.2.3 through 2.3.6;

s. Revising section 2.4.1;

t. Removing section 2.4.2, and redesignating sections 2.4.3, 2.4.3.1, 2.4.3.2, 2.4.3.3 and 2.4.4 as sections 2.4.2, 2.4.2.1, 2.4.2.2, 2.4.2.3 and 2.4.3, respectively; and

u. Revising newly redesignated sections 2.4.2, 2.4.2.1, and 2.4.2.3 to read as follows:

2. Procedure

2.1 Fuel Flowmeter Measurements

For each hour when the unit is combusting fuel, measure and record the flow rate of fuel combusted by the unit, except as provided in section 2.1.4 of this appendix. Measure the flow rate of fuel with an in-line fuel flowmeter, and automatically record the data with a data acquisition and handling system, except as provided in section 2.1.4 of this appendix.

2.1.1 Measure the flow rate of each fuel entering and being combusted by the unit. If, on an annual basis, more than 5.0 percent of the fuel from the main pipe is diverted from the unit without being burned and that diversion occurs downstream of the fuel flowmeter, an additional in-line fuel flowmeter is required to account for the unburned fuel. In this case, record the flow rate of each fuel combusted by the unit as the difference between the flow measured in the pipe leading to the unit and the flow in the pipe diverting fuel away from the unit. However, the additional fuel flowmeter is not required if, on an annual basis, the total amount of fuel diverted away from the unit, expressed as a percentage of the total annual fuel usage by the unit is demonstrated to be less than or equal to 5.0 percent. The owner or operator may make this demonstration in the following manner:

2.1.1.1 For existing units with fuel usage data from fuel flowmeters, if data are submitted from a previous year demonstrating that the total diverted yearly fuel does not exceed 5% of the total fuel used; or

2.1.1.2 For new units which do not have historical data, if a letter is submitted signed by the designated representative certifying that, in the future, the diverted fuel will not exceed 5.0% of the total annual fuel usage ; or

2.1.1.3 By using a method approved by the Administrator under § 75.66(d).

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 (i.e., a pipe carrying fuel for multiple units). 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 are not applicable 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. For all other units, if the fuel flowmeter is installed in a common pipe header, do one of the following:

2.1.2.1 Measure the fuel flow rate in the common pipe, and combine SO_2 mass emissions for the affected units for recordkeeping and compliance purposes; or

2.1.2.2 Provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions and heat input to each of the affected units demonstrating that the method ensures complete and accurate accounting of the actual emissions from each of the affected units included in the apportionment and all emissions regulated under this part. The information shall be provided to the Administrator through a petition submitted by the designated representative under § 75.66. Satisfactory information includes: the proposed apportionment, using fuel flow measurements; the ratio of hourly integrated gross load (in MWe-hr) in each unit to the total load for all units receiving fuel from the common pipe header, or the ratio of hourly steam flow (in 1000 lb) at each unit to the total steam flow for all units receiving fuel from the common pipe header (see section 3.4.3 of this appendix); and documentation that shows the provisions of sections 2.1.5 and 2.1.6 of this appendix have been met for the fuel flowmeter used in the apportionment.

2.1.3 For a gas-fired unit or an oil-fired unit that continuously or frequently combusts a supplemental fuel for flame stabilization or safety purposes, measure the flow rate of the supplemental fuel with a fuel flowmeter meeting the requirements of this appendix.

2.1.4 Situations in Which Certified Flowmeter is Not Required

2.1.4.1 Start-up or Ignition Fuel

For an oil-fired unit that uses gas solely for start-up or burner ignition or a gas-fired unit that uses oil solely for start-up or burner ignition, a flowmeter for the start-up fuel is not required. Estimate the volume of oil combusted for each start-up or ignition either by using a fuel flowmeter or by using the dimensions of the storage container and measuring the depth of the fuel in the storage container before and after each start-up or ignition. A fuel flowmeter used solely for start-up or ignition fuel is not subject to the calibration requirements of sections 2.1.5 and 2.1.6 of this appendix. Gas combusted solely for start-up or burner ignition does not need to be measured separately.

2.1.4.2 Gas or Oil Flowmeter Used for Commercial Billing

A gas or oil flowmeter used for commercial billing of natural gas or oil may be used to measure, record, and report hourly fuel flow rate. A gas or oil flowmeter used for commercial billing of natural gas or oil is not required to meet the certification requirements of section 2.1.5 of this appendix or the quality assurance requirements of section 2.1.6 of this appendix under the following circumstances:

(a) The gas or oil flowmeter is used for commercial billing under a contract, provided that the company providing the gas or oil under the contract and each unit combusting the gas or oil do not have any common owners and are not owned by subsidiaries or affiliates of the same company;

(b) The designated representative reports hourly records of gas or oil flow rate, heat input rate, and emissions due to combustion of natural gas or oil;

(c) The designated representative also reports hourly records of heat input rate for each unit, if the gas or oil flowmeter is on a common pipe header, consistent with section 2.1.2 of this appendix;

(d) The designated representative reports hourly records directly from the gas or oil flowmeter used for commercial billing if these records are the values used, without adjustment, for commercial billing, or reports hourly records using the missing data procedures of section 2.4 of this appendix if these records are not the values used, without adjustment, for commercial billing; and

(e) The designated representative identifies the gas or oil flowmeter in the unit's monitoring plan.

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. Additionally, begin sampling the emergency fuel for sulfur content only using the procedures under section 2.2 (for oil) or 2.3 (for gas) of this appendix. The designated representative shall also provide notice under § 75.61(a)(6)(ii) for each period when the emergency fuel is combusted.

2.1.5 Initial Certification Requirement for all Fuel Flowmeters

For the purposes of initial certification, each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of 2.0 percent of the upper range value (i.e. maximum calibrated fuel flow rate) across the range of fuel flow rate to be measured at the unit. Flowmeter accuracy may be determined under section 2.1.5.1 of this appendix for initial certification in any of the following ways (as applicable): by design or by measurement under laboratory conditions; by the manufacturer; by an independent laboratory; or by the owner or operator. Flowmeter accuracy may also be determined under section 2.1.5.2 of this appendix by measurement against a NIST traceable reference method.

2.1.5.1 Use the procedures in the following standards to verify flowmeter accuracy or design, as appropriate to the type of flowmeter: ASME MFC–3M–1989 with September 1990 Errata (''Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi''); ASME MFC–4M–1986 (Reaffirmed 1990), ''Measurement of Gas Flow by Turbine Meters;'' American Gas Association Report No. 3, ''Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines''

(October 1990 Edition), Part 2: ''Specification and Installation Requirements'' (February 1991 Edition), and Part 3: ''Natural Gas Applications'' (August 1992 edition) (excluding the modified flow-calculation method in part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April, 1996); ASME MFC–5M–1985 (''Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters''); ASME MFC–6M–1987 with June 1987 Errata (''Measurement of Fluid Flow in Pipes Using Vortex Flow Meters''); ASME MFC–7M–1987 (Reaffirmed 1992), ''Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles;'' ISO 8316: 1987(E) ''Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank;'' American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers'', Section 3, ''Small Volume Provers'', and Section 5, ''Master-Meter Provers'', from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993); or ASME MFC–9M–1988 with December 1989 Errata (''Measurement of Liquid Flow in Closed Conduits by Weighing Method''), for all other flowmeter types (incorporated by reference under § 75.6). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document such procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit, and submit a petition signed by the designated representative under § 75.66(c). If the flowmeter accuracy exceeds 2.0 percent of the upper range value, the flowmeter does not qualify for use under this part.

2.1.5.2 (a) Alternatively, determine the flowmeter accuracy of a fuel flowmeter used for the purposes of this part by comparing it to the measured flow from a reference flowmeter which has been either designed according to the specifications of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix, or tested for accuracy during the previous 365 days, using a standard listed in section 2.1.5.1 of this appendix or other procedure approved by the Administrator under § 75.66 (all standards incorporated by reference under § 75.6). Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow rate readings over 20 minutes or longer for each meter at each of three different flow rate levels. The three flow rate levels shall correspond to:

(1) Normal full unit operating load,

(2) Normal minimum unit operating load,

(3) A load point approximately equally spaced between the full and minimum unit operating loads, and

(4) Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

$$ACC = \frac{|R - A|}{URV} \times 100 \qquad \text{(Eq. D-1)}$$

Where:

ACC=Flowmeter accuracy at a particular load level, as a percentage of the upper range value.

R=Average of the three flow measurements of the reference flowmeter.

A=Average of the three measurements of the flowmeter being tested.

URV=Upper range value of fuel flowmeter being tested (i.e. maximum measurable flow).

(c) Notwithstanding the requirement for calibration of the reference flowmeter within 365 days prior to an accuracy test, when an in-place reference meter or prover is used for quality assurance under section 2.1.6 of this appendix, the reference meter calibration requirement may be waived if, during the previous in-place accuracy test with that reference meter, the reference flowmeter and the flowmeter being tested agreed to within ±1.0 percent of each other at all levels tested. This exception to calibration and flowmeter accuracy testing requirements for the reference flowmeter shall apply for periods of no longer than five consecutive years (i.e., 20 consecutive calendar quarters).

2.1.5.3 If the flowmeter accuracy exceeds the specification in section 2.1.5 of this appendix, the flowmeter does not qualify for use for this appendix. Either recalibrate the flowmeter until the flowmeter accuracy is within the performance specification, or replace the flowmeter with another one that is demonstrated to meet the performance specification. Substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix until quality assured fuel flow data become available.

2.1.5.4 For purposes of initial certification, when a flowmeter is tested against a reference fuel flow rate (i.e., fuel flow rate from another fuel flowmeter under section 2.1.5.2 of this appendix or flow rate from a procedure performed according to a standard incorporated by reference under section 2.1.5.1 of this appendix), report the results of flowmeter accuracy tests using the following Table D–1.

TABLE D–1.—TABLE OF FLOWMETER ACCURACY RESULTS

Test number:_______ Test completion date [1]:__________________ Test completion time [1]:___________
Reinstallation date [2] (for testing under 2.1.5.1 only):__________________ Reinstallation time [2]:___________
Unit or pipe ID: Component/System ID:
Flowmeter serial number: Upper range value:
Units of measure for flowmeter and reference flow readings:

Measurement level (percent of URV)	Run No.	Time of run (HHMM)	Candidate flowmeter reading	Reference flow reading	Percent accuracy (percent of URV)
Low (Minimum) level	1	....	....	....	....
____ percent [3] of URV	2	....	....	....	....
	3	....	....	....	....
	Average	....	....	....	....
Mid-level	1	....	....	....	....
____ percent [3] of URV	2	....	....	....	....
	3	....	....	....	....
	Average	....	....	....	....
High (Maximum) level	1	....	....	....	....
____ percent [3] of URV	2	....	....	....	....
	3	....	....	....	....
	Average	....	....	....	....

[1] Report the date, hour, and minute that all test runs were completed.

[2] For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.

[3] It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

2.1.6 Quality Assurance

(a) Test the accuracy of each fuel flowmeter prior to use under this part and at least once every four fuel flowmeter QA operating quarters, as defined in § 72.2 of this chapter, thereafter. Notwithstanding these requirements, no more than 20 successive calendar quarters shall elapse after the quarter in which a fuel flowmeter was last tested for accuracy without a subsequent flowmeter accuracy test having been conducted. Test the flowmeter accuracy more frequently if required by manufacturer specifications.

(b) Except for orifice-, nozzle-, and venturi-type flowmeters, perform the required flowmeter accuracy testing using the procedures in either section 2.1.5.1 or section 2.1.5.2 of this appendix. Each fuel flowmeter must meet the accuracy specification in section 2.1.5 of this appendix.

(c) For orifice-, nozzle-, and venturi-type flowmeters, either perform the required flowmeter accuracy testing using the procedures in section 2.1.5.1 or 2.1.5.2 of this appendix or perform a transmitter accuracy test once every four fuel flowmeter QA operating quarters and a primary element visual inspection once every 12 calendar quarters, according to the procedures in sections 2.1.6.1 through 2.1.6.4 of this appendix for periodic quality assurance.

(d) Notwithstanding the requirements of this section, if the procedures of section 2.1.7 (fuel flow-to-load test) of this appendix are performed during each fuel flowmeter QA operating quarter, subsequent to a required flowmeter accuracy test or transmitter accuracy test and primary element inspection, where applicable, those procedures may be used to meet the requirement for periodic quality assurance testing for a period of up to 20 calendar quarters from the previous accuracy test or transmitter accuracy test and primary element inspection, where applicable.

2.1.6.1 Transmitter or Transducer Accuracy Test for Orifice-, Nozzle-, and Venturi-Type Flowmeters

(a) Calibrate the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. Check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at each of the following levels: the zero-level and at least two other levels (e.g., ''mid'' and ''high''), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented.

(b) Calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R - T|}{FS} \times 100 \qquad \text{(Eq. D-1a)}$$

Where:

ACC = Accuracy of the transmitter or transducer as a percentage of full-scale.

R = Reading of the NIST traceable reference value (in milliamperes, inches of water, psi, or degrees).

T = Reading of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

FS = Full-scale range of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

(c) If each transmitter or transducer meets an accuracy of ± 1.0 percent of its full-scale range at each level tested, the fuel flowmeter accuracy of 2.0 percent is considered to be met at all levels. If, however, one or more of the transmitters or transducers does not meet an accuracy of ± 1.0 percent of full-scale at a particular level, then the owner or operator may demonstrate that the fuel flowmeter meets the total accuracy specification of 2.0 percent at that level by using one of the following alternative methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0 percent, the fuel flowmeter accuracy specification of 2.0 percent is considered to be met for that level. Or, if at a particular level, the total fuel flowmeter accuracy is 2.0 percent or less, when calculated in accordance with Part 1 of American Gas Association Report No. 3, General Equations and Uncertainty Guidelines, the flowmeter accuracy requirement is considered to be met for that level.

2.1.6.2 Recordkeeping and Reporting of Transmitter or Transducer Accuracy Results

(a) Record the accuracy of the orifice, nozzle, or venturi meter or its individual transmitters or transducers and keep this information in a file at the site or other location suitable for inspection. When testing individual orifice, nozzle, or venturi meter transmitters or transducers for accuracy, include the information displayed in the following Table D–2. At a minimum, record results for each transmitter or transducer at the zero-level and at least two other levels across the range of the transmitter or transducer readings that correspond to normal unit operation.

TABLE D–2.—TABLE OF FLOWMETER TRANSMITTER OR TRANSDUCER ACCURACY RESULTS

Test number:_______ Test completion date: __________________ Unit or pipe ID: ___________
Flowmeter serial number: Component/System ID:
Full-scale value: Units of measure:[3]
Transducer/Transmitter Type (check one):
____ Differential Pressure
____ Static Pressure
____ Temperature

Measurement level (percent of full-scale)	Run number (if multiple runs)[2]	Run time (HHMM)	Transmitter/ transducer input (pre-calibration)	Expected transmitter/ transducer output (reference)	Actual transmitter/ transducer output[3]	Percent accuracy (percent of full-scale)
Low (Minimum) level ____ percent[1] of full-scale	....					
Mid-level ____ percent[1] of full-scale	....					
(If tested at more than 3 levels) 2nd Mid-level ____ percent[1] of full-scale	....					
(If tested at more than 3 levels) 3rd Mid-level ____ percent[1] of full-scale	....					
High (Maximum) level ____ percent[1] of full-scale	....					

[1] At a minimum, it is required to test at zero-level and at least two other levels across the range of the transmitter or transducer readings corresponding to normal unit operation.
[2] It is required to test at least once at each level.
[3] Use the same units of measure for all readings (e.g., use degrees (°), inches of water (in H_2O), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

(b) 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 flowmeter accuracy results for the fuel flowmeter at the three flow rate levels specified in section 2.1.5.2 of this appendix.

(c) 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.

2.1.6.3 Failure of Transducer(s) or Transmitter(s)

If, during a transmitter or transducer accuracy test conducted according to section 2.1.6.1 of this appendix, the flowmeter accuracy specification of 2.0 percent is not met at any of the levels tested, repair or replace transmitter(s) or transducer(s) as necessary until the flowmeter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels, to ensure that the flowmeter accuracy specification is met at each level). The fuel flowmeter is ''out-of-control'' and data from the flowmeter are considered invalid, beginning with the date and hour of the failed accuracy test and continuing until the date and hour of completion of a successful transmitter or transducer accuracy test at all levels. In addition, if, during normal operation of the fuel flowmeter, one or more transmitters or transducers malfunction, data from the fuel flowmeter shall be considered invalid from the hour of the transmitter or transducer failure until the hour of completion of a successful 3-level transmitter or transducer accuracy test. During fuel flowmeter out-of-control periods, provide data from another fuel flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix. Record and report test data and results, consistent with sections 2.1.6.1 and 2.1.6.2 of this appendix and § 75.56 or § 75.59, as applicable.

2.1.6.4 Primary Element Inspection

(a) Conduct a visual inspection of the orifice, nozzle, or venturi meter at least once every twelve calendar quarters. Notwithstanding this requirement, the procedures of section 2.1.7 of this appendix may be used to reduce the inspection frequency of the orifice, nozzle, or venturi meter to at least once every twenty calendar quarters. The inspection may be performed using a baroscope. If the visual inspection indicates that the orifice, nozzle, or venturi meter has become damaged or corroded, then:

(1) Replace the primary element with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6);

(2) Replace the primary element with another primary element, and demonstrate that the overall flowmeter accuracy meets the accuracy specification in section 2.1.5 of this appendix under the procedures of section 2.1.5.2 of this appendix; or

(3) Restore the damaged or corroded primary element to ''as new'' condition; determine the overall accuracy of the flowmeter, using either the specifications of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6); and retest the transmitters or transducers prior to providing quality assured data from the flowmeter.

(b) If the primary element size is changed, calibrate the transmitter or transducers consistent with the new primary element size. Data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed visual inspection and continuing until the date and hour when:

(1) The damaged or corroded primary element is replaced with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6);

(2) The damaged or corroded primary element is replaced, and the overall accuracy of the flowmeter is demonstrated to meet the accuracy specification in section 2.1.5 of this appendix under the procedures of section 2.1.5.2 of this appendix; or

(3) The restored primary element is installed to meet the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6) and its transmitters or transducers are retested to meet the accuracy specification in section 2.1.6.1 of this appendix.

(c) During this period, provide data from another fuel flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix.

2.1.7 Fuel Flow-to-Load Quality Assurance Testing for Certified Fuel Flowmeters

The procedures of this section may be used as an optional supplement to the quality assurance procedures in section 2.1.5.1, 2.1.5.2, 2.1.6.1, or 2.1.6.4 of this appendix when conducting periodic quality assurance testing of a certified fuel flowmeter. Note, however, that these procedures may not be used unless the 168-hour baseline data requirement of section 2.1.7.1 of this appendix has been met. If, following a flowmeter accuracy test or flowmeter transmitter test and primary element inspection, where applicable, the procedures of this section are performed during each subsequent fuel flowmeter QA operating quarter, as defined in § 72.2 of this chapter (excluding the quarter(s) in which the baseline data are collected), then these procedures may be used to meet the requirement for periodic quality assurance for a period of up to 20 calendar quarters from the previous periodic quality assurance procedure(s) performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 through 2.1.6.4 of this appendix. The procedures of this section are not required for any quarter in which a flowmeter accuracy test or a transmitter accuracy test and a primary element inspection, where applicable, are conducted. Notwithstanding the requirements of § 75.54(a) or § 75.57(a), as applicable, when using the procedures of this section, keep records of the test data and results from the previous flowmeter accuracy test under section 2.1.5.1 or 2.1.5.2 of this appendix, records of the test data and results from the previous transmitter or transducer accuracy test under section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters, and records of the previous visual inspection of the primary element required under section 2.1.6.4 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters until the next flowmeter accuracy test, transmitter accuracy test, or visual inspection is performed, even if the previous flowmeter accuracy test, transmitter accuracy test, or visual inspection was performed more than three years previously.

2.1.7.1 Baseline Flow Rate-to-Load Ratio or Heat Input-to-Load Ratio

(a) Determine R_{base}, the baseline value of the ratio of fuel flow rate to unit load, following each successful periodic quality assurance procedure performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 and 2.1.6.4 of this appendix. Establish a baseline period of data consisting, at a minimum, of 168 hours of quality assured fuel flowmeter data. Baseline data collection shall begin with the first hour of fuel flowmeter operation following completion of the most recent quality assurance procedure(s), during which only the fuel measured by the fuel flowmeter is combusted (i.e., only gas, only residual oil, or only diesel fuel is combusted by the unit). During the baseline data collection period, the owner or operator may exclude as non-representative any hour in which the unit is ''ramping'' up or down, (i.e., the load during the hour differs by more than 15.0 percent from the load in the previous or subsequent hour) and may exclude any hour in which the unit load is 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 this lower 25.0 percent of the range is considered normal for the unit). The baseline data must be obtained no later than the end of the fourth calendar quarter following the calendar quarter of the most recent quality assurance procedure for that fuel flowmeter. 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 of both the most recent transmitter or transducer test and the most recent primary element inspection for that fuel flowmeter. From these 168 (or more) hours of baseline data, calculate the baseline fuel flow rate-to-load ratio as follows:

$$R_{base} = \frac{Q_{base}}{L_{avg}} \qquad \text{(Eq. D-1b)}$$

where:

R_{base} = Value of the fuel flow rate-to-load ratio during the baseline period; 100 scfh/MWe or 100 scfh/klb per hour steam load for gas-firing; (lb/hr)/MWe or (lb/hr)/klb per hour steam load for oil-firing.

Q_{base} = Average fuel flow rate measured by the fuel flowmeter during the baseline period, 100 scfh for gas-firing and lb/hr for oil-firing.

L_{avg} = Average unit load during the baseline period, megawatts or 1000 lb/hr of steam.

(b) In Equation D–1b, for a common pipe header, L_{avg} is the sum of the operating loads of all units that receive fuel through the common pipe header. For a unit that receives its fuel through multiple pipes, Q_{base} is the sum of the fuel flow rates for a particular fuel (i.e., gas, diesel fuel, or residual oil) from each of the pipes. Round off the value of R_{base} to the nearest tenth.

(c) Alternatively, a baseline value of the gross heat rate (GHR) may be determined in lieu of R_{base}. The baseline value of the GHR, GHR_{base}, shall be determined as follows:

$$(GHR)_{base} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000 \qquad \text{(Eq. D-1c)}$$

Where:

$(GHR)_{base}$ = Baseline value of the gross heat rate during the baseline period, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_{avg}$ = Average (mean) hourly heat input rate recorded by the fuel flowmeter during the baseline period, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

L_{avg} = Average (mean) unit load during the baseline period, megawatts or 1000 lb/hr of steam.

(d) Report the current value of R_{base} (or GHR_{base}) and the completion date of the associated quality assurance procedure in each electronic quarterly report required under § 75.64.

2.1.7.2 Data Preparation and Analysis

(a) Evaluate the fuel flow rate-to-load ratio (or GHR) for each fuel flowmeter QA operating quarter, as defined in § 72.2 of this chapter. At the end of each fuel flowmeter QA operating quarter, use Equation D–1d in this appendix to calculate R_h, the hourly fuel flow-to-load ratio, for every quality assured hourly average fuel flow rate obtained with a certified fuel flowmeter.

$$R_h = \frac{Q_h}{L_h} \qquad \text{(Eq. D-1d)}$$

where:

R_h = Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, or (lb/hr)/1000 lb/hr of steam load.

Q_h = Hourly fuel flow rate, as measured by the fuel flowmeter, 100 scfh for gas-firing or lb/hr for oil-firing.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam.

(b) For a common pipe header, L_h shall be the sum of the hourly operating loads of all units that receive fuel through the common pipe header. For a unit that receives its fuel through multiple pipes, Q_h will be the sum of the fuel flow rates for a particular fuel (i.e., gas, diesel fuel, or residual oil) from each of the pipes. Round off each value of R_h to the nearest tenth.

(c) Alternatively, calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000 \qquad \text{(Eq. D-1e)}$$

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_h$ = Hourly heat input rate, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam.

(d) Evaluate the calculated flow rate-to-load ratios (or gross heat rates) as follows. Perform a separate data analysis for each fuel flowmeter following the procedures of this section. Base each analysis on a minimum of 168 hours of data. If, for a particular fuel flowmeter, fewer than 168 hourly flow-to-load ratios (or GHR values) are available, a flow-to-load (or GHR) evaluation is not required for that flowmeter for that calendar quarter.

(e) For each hourly flow-to-load ratio or GHR value, calculate the percentage difference (percent D_h) from the baseline fuel flow-to-load ratio using Equation D–1f.

$$\%D_h = \frac{\left|R_{base} - R_h\right|}{R_{base}} \times 100 \qquad \text{(Eq. D-1f)}$$

Where:

$\%D_h$ = Absolute value of the percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

R_h = The hourly fuel flow rate-to-load ratio (or GHR).

R_{base} = The value of the fuel flow rate-to-load ratio (or GHR) from the baseline period, determined in accordance with section 2.1.7.1 of this appendix.

(f) Consistently use R_{base} and R_h in Equation D–1f if the fuel flow-to-load ratio is being evaluated, and consistently use $(GHR)_{base}$ and $(GHR)_h$ in Equation D–1f if the gross heat rate is being evaluated.

(g) Next, determine the arithmetic average of all of the hourly percent difference (percent D_h) values using Equation D–1g, as follows:

$$E_f = \sum_{h=1}^{q} \frac{\%D_h}{q} \qquad \text{(Eq. D-1g)}$$

Where:

E_f = Quarterly average percentage difference between hourly flow rate-to-load ratios and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

$\%D_h$ = Percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

q = Number of hours used in fuel flow-to-load (or GHR) evaluation.

(h) When the quarterly average load value used in the data analysis is greater than 50 MWe (or 500 klb steam per hour), the results of a quarterly fuel flow rate-to-load (or GHR) evaluation are acceptable and no further action is required if the quarterly average percentage difference (E_f) is no greater than 10.0 percent. When the arithmetic average of the hourly load values used in the data analysis is ≤50 MWe (or 500 klb steam per hour), the results of the analysis are acceptable if the value of E_f is no greater than 15.0 percent.

2.1.7.3 Optional Data Exclusions

(a) If E_f is outside the limits in section 2.1.7.2 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 identify and exclude fuel flow-to-load ratios or GHR values for any non-representative fuel flow-to-load ratios or GHR values. Specifically, the R_h or $(GHR)_h$ values for the following hours may be considered non-representative: any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; or 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 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) After identifying and excluding all non-representative hourly fuel flow-to-load ratios or GHR values, analyze the quarterly fuel flow rate-to-load data a second time.

2.1.7.4 Consequences of Failed Fuel Flow-to-Load Ratio Test

(a) If E_f is outside the applicable limit in section 2.1.7.2 of this appendix (after analysis using any optional data exclusions under section 2.1.7.3 of this appendix), perform transmitter accuracy tests according to section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type flowmeters, or perform a fuel flowmeter accuracy test, in accordance with section 2.1.5.1 or 2.1.5.2 of this appendix, for each fuel flowmeter for which E_f is outside of the applicable limit. In addition, for an orifice-, nozzle-, or venturi-type fuel flowmeter, repeat the fuel flow-to-load ratio comparison of section 2.1.7.2 of this appendix using six to twelve hours of data following a passed transmitter accuracy test in order to verify that no significant corrosion has affected the primary element. If, for the abbreviated 6-to-12 hour test, the orifice-, nozzle-, or venturi-type fuel flowmeter is not able to meet the limit in section 2.1.7.2 of this appendix, then perform a visual inspection of the primary element according to section 2.1.6.4 of this appendix, and repair or replace the primary element, as necessary.

(b) Substitute for fuel flow rate, for any hour when that fuel is combusted, using the missing data procedures in section 2.4.2 of this appendix, beginning with the first hour of the calendar quarter following the quarter for which E_f was found to be outside the applicable limit and continuing until quality assured fuel flow data become available. Following a failed flow rate-to-load or GHR evaluation, data from the flowmeter shall not be considered quality assured until the hour in which all required flowmeter accuracy tests, transmitter accuracy tests, visual inspections and diagnostic tests have been passed. Additionally, a new value of R_{base} or $(GHR)_{base}$ shall be established no later than two flowmeter QA operating quarters after the quarter in which the required quality assurance tests are completed (note that for orifice-, nozzle-, or venturi-type fuel flowmeters, establish a new value of R_{base} or $(GHR)_{base}$ only if both a transmitter accuracy test and a primary element inspection have been performed).

2.1.7.5 Test Results

Report the results of each quarterly flow rate-to-load (or GHR) evaluation, as determined from Equation D–1g, in the electronic quarterly report required under § 75.64. Table D–3 is provided as a reference on the type of information to be recorded under § 75.59 and reported under § 75.64.

TABLE D–3.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST

Plant name:__________________State:_____ORIS code:__________________
Unit/pipe ID #:___________Fuel flowmeter component and system ID #s:_______-_______Calendar quarter (1st, 2nd, 3rd, 4th) and year:___________
Range of operation:___________ to ___________ MWe or klb steam/hr (indicate units)

Time period	
Baseline period	Quarter
Completion date and time of most recent primary element inspection (orifice-, nozzle-, and venturi-type flowmeters only). ____/____/____ ____:____	Number of hours excluded from quarterly average due to co-firing different fuels:_______ hrs.
Completion date and time of the most recent flowmeter or transmitter accuracy test ____/____/____ ____:____	Number of hours excluded from quarterly average due to ramping load: _______ hrs.
Beginning 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.
End date and time of baseline period ____/____/____ ____:____	Number of hours included in quarterly average: _______ hrs.
Average fuel flow rate__________________ (100 scfh for gas and lb/hr for oil)	Quarterly percentage difference between hourly ratios and baseline ratio: _______ percent.
Average load;__________________ (MWe or 1000 lb steam/hr) 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 ration or GHR: _______ hrs.	Test result: pass, fail.

2.2 Oil Sampling and Analysis

Perform sampling and analysis of oil to determine the following fuel properties for each type of oil combusted by a unit: percentage of sulfur by weight in the oil; gross calorific value (GCV) of the oil; and, if necessary, the density of the oil. Use the sulfur content, density, and gross calorific value, determined under the provisions of this section, to calculate SO_2 mass emission rate and heat input rate for each fuel using the applicable procedures of section 3 of this appendix. The designated representative may petition for reduced GCV and or density sampling under § 75.66 if the fuel combusted has a consistent and relatively non-variable GCV or density.

TABLE D–4.—OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations
Oil Sulfur Content	Daily manual sampling	1. Highest sulfur content from previous 30 daily samples; or 2. Actual daily value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year; or 3. Maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year; or 2. Maximum value allowed by contract.[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; or 3. Maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year; or 2. Maximum value allowed by contract.[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; or 3. Maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year; or 2. Maximum value allowed by contract.[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.

2.2.1 When combusting oil, use one of the following methods to sample the oil (see Table D–4): sample from the storage tank for the unit after each addition of oil to the storage tank, in accordance with section 2.2.4.2 of this appendix; or sample from the fuel lot in the shipment tank or container upon receipt of each oil delivery or from the fuel lot in the oil supplier's storage container, in accordance with section 2.2.4.3 of this appendix; or use the flow proportional sampling methodology in section 2.2.3 of this appendix; or use the daily manual sampling methodology in section 2.2.4.1 of this appendix. For purposes of this appendix, a fuel lot of oil is the mass or volume of product oil from one source (supplier or pretreatment facility), intended as one shipment or delivery (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through pipeline, etc.). A storage tank is a container at a plant holding oil that is actually combusted by the unit, such that no blending of any other fuel with the fuel in the storage tank occurs from the time that the fuel lot is transferred to the storage tank to the time when the fuel is combusted in the unit.

2.2.2 [Reserved]

2.2.3 Flow Proportional Sampling

Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177–82 (Reapproved 1990), ''Standard Practice for Automatic Sampling of Petroleum and Petroleum Products'' (incorporated by reference under § 75.6), every day the unit is combusting oil. Extract oil at least once every hour and blend into a composite sample. The sample compositing period may not exceed 7 calendar days (168 hrs). Use the actual sulfur content (and where density data are required, the actual density) from the composite sample to calculate the hourly SO_2 mass emission rates for each operating day represented by the composite sample. Calculate the hourly heat input rates for each operating day represented by the composite sample, using the actual gross calorific value from the composite sample.

2.2.4 Manual Sampling

2.2.4.1 Daily Samples

Representative oil samples may be taken from the storage tank or fuel flow line manually every day that the unit combusts oil according to ASTM D4057–88, ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products'' (incorporated by reference under § 75.6). Use either the actual daily sulfur content or the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples for the purpose of calculating SO_2 emissions under section 3 of this appendix. Use either the gross calorific value measured from that day's sample or the highest GCV from the previous 30 days' samples to calculate heat input. If oil supplies with different sulfur contents are combusted on the same day, sample the highest sulfur fuel combusted that day.

2.2.4.2 Sampling From a Unit's Storage Tank

Take a manual sample after each addition of oil to the storage tank. Do not blend additional fuel with the sampled fuel prior to combustion. Sample according to the single tank composite sampling procedure or all-levels sampling procedure in ASTM D4057–88, ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products'' (incorporated by reference under § 75.6). Use the sulfur content (and where required, the density) of either the most recent sample or one of the conservative assumed values described in section 2.2.4.3 of this appendix to calculate SO_2 mass emission rate. Calculate heat input rate using the gross calorific value from either:

(a) The most recent oil sample taken or

(b) One of the conservative assumed values described in section 2.2.4.3 of this appendix.

2.2.4.3 Sampling From Each Delivery

(a) Alternatively, an oil sample may be taken from—

(1) The shipment tank or container upon receipt of each lot of fuel oil or

(2) The supplier's storage container which holds the lot of fuel oil. (Note: a supplier need only sample the storage container once for sulfur content, GCV and, where required, the density so long as the fuel sulfur content and GCV do not change and no fuel is added to the supplier's storage container.)

(b) For the purpose of this section, a lot is defined as a shipment or delivery (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through a pipeline, etc.) of a single fuel.

(c) Oil sampling may be performed either by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that samples are representative and that sampling is performed according to either the single tank composite sampling procedure or the all-levels sampling procedure in ASTM D4057–88, ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products'' (incorporated by reference under § 75.6). Except as otherwise provided in this section, calculate SO_2 mass emission rate using the sulfur content (and where required, the density) from one of the two following values, and calculate heat input using the gross calorific value from one of the two following values:

(1) The highest value sampled during the previous calendar year (this option is allowed for any consistent fuel which comes from a single source whether or not the fuel is supplied under a contractual agreement) or

(2) The maximum value indicated in the contract with the fuel supplier. Continue to use this assumed contract value unless and until the actual sampled sulfur content, density, or gross calorific value of a delivery exceeds the assumed value.

(d) 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 use the actual sampled value for sulfur content, gross calorific value, or density of fuel to calculate SO_2 mass emission rate or heat input rate as the new assumed sulfur content, gross calorific value, or density. Continue to use this new assumed value to calculate SO_2 mass emission rate or heat input rate unless and until: it is superseded by a higher value from an oil sample; or 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.

* * * * *

2.2.6 Where the flowmeter records volumetric flow rate rather than mass flow rate, analyze oil samples to determine the density or specific gravity of the oil. * * *

* * * * *

2.2.8 Results from the oil sample analysis must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results of the analysis be available as soon as practicable, and no later than 5 business days after receipt of a request from the Administrator.

2.3 SO_2 Emissions From Combustion of Gaseous Fuels

(a) Account for the hourly SO_2 mass emissions due to combustion of gaseous fuels for each hour when gaseous fuels are combusted by the unit using the procedures in this section.

(b) The procedures in sections 2.3.1 and 2.3.2 of this appendix, respectively, may be used to determine SO_2 mass emissions from combustion of pipeline natural gas and natural gas, as defined in § 72.2 of this chapter. The procedures in section 2.3.3 of this appendix may be used to account for SO_2 mass emissions from any gaseous fuel combusted by a unit. For each type of gaseous fuel, the appropriate sampling frequency and the sulfur content and GCV values used for calculations of SO_2 mass emission rates are summarized in the following Table D–5.

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
Gas Sulfur Content	Pipeline Natural Gas with H_2S content less than or equal to 0.3 grains/100scf when using the provisions of section 2.3.1 to determine SO_2 mass emissions.	0.0006 lb/mmBtu.
	Natural Gas with H_2S content less than or equal to 1.0 grain/100scf when using the provisions of section 2.3.2 to determine SO_2 mass emissions.	Default SO_2 emission rate calculated from Eq. D–1h, using either the fuel contract maximum H_2S or the maximum H_2S from historical sampling data.
	Any gaseous fuel delivered in shipments or lots—Sample each lot or shipment.	Actual % sulfur from most recent shipment *or* 1. Highest % sulfur from previous year's samples [1]; or 2. Maximum % sulfur value allowed by contract [1].
	Any gaseous fuel transmitted by pipeline and having a demonstrated ''low sulfur variability'' using the provisions of section 2.3.6—Sample daily.	Actual % sulfur from daily sample; or Highest % sulfur from previous 30 daily samples.
	Any gaseous fuel—Sample hourly	Actual hourly sulfur content of the gas.
Gas GCV	Pipeline Natural Gas—Sample monthly	1. GCV from most recent monthly sample (with $\geq$ 48 operating hours in the month); or 2. Maximum GCV from contract [1]; *or* 3. Highest GCV from previous year's samples.[1]
	Natural Gas—Sample monthly	1. GCV from most recent monthly sample (with $\geq$ 48 operating hours in the month); or 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.	Actual GCV from most recent shipment or lot *or* 1. Highest GCV from previous year's samples1; or 2. Maximum GCV value allowed by contract.[1]
	Any gaseous fuel transmitted by pipeline and having a demonstrated ''low GCV variability'' using the provisions of section 2.3.5—Sample monthly.	1. GCV from most recent monthly sample (with $\geq$ 48 operating hours in the month); or 2. Highest GCV from previous year's samples.[1]
	Any other gaseous fuel not having a ''low GCV variability''—Sample at least daily. (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.

2.3.1 Pipeline Natural Gas Combustion

The owner or operator may determine the SO_2 mass emissions from the combustion of a fuel that meets the definition of pipeline natural gas, in § 72.2 of this chapter, using the procedures of this section.

2.3.1.1 SO_2 Emission Rate

For a fuel that meets the definition of pipeline natural gas under § 72.2 of this chapter, the owner or operator may determine the SO_2 mass emissions using either a default SO_2 emission rate of 0.0006 lb/mmBtu and the procedures of this section, the procedures in section 2.3.2 for natural gas, or the procedures of section 2.3.3 for any gaseous fuel. For each affected unit using the default rate of 0.0006 lb/mmBtu, the owner or operator must document that the fuel combusted is actually pipeline natural gas, using the procedures in section 2.3.1.4 of this appendix.

2.3.1.2 Hourly Heat Input Rate

Calculate hourly heat input rate, in mmBtu/hr, for a unit combusting pipeline natural gas, using the procedures of section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.1 of this appendix in the calculations.

2.3.1.3 SO_2 Hourly Mass Emission Rate and Hourly Mass Emissions

For pipeline natural gas combustion, calculate the SO2 mass emission rate, in lb/hr, using Equation D–5 in section 3.3.2 of this appendix (when the default SO_2 emission rate is used). Then, use the calculated SO_2 mass emission rate and the unit operating time to determine the hourly SO_2 mass emissions from pipeline natural gas combustion, in lb, using Equation D–12 in section 3.5.1 of this appendix.

2.3.1.4 Documentation That a Fuel Is Pipeline Natural Gas

(a) For pipeline natural gas, provide information 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 has a hydrogen sulfide content of less than 0.3 grain/100scf. The demonstration must be made using one of the following sources of information:

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

(2) A certification of the gas vendor, based on routine vendor sampling and analysis (minimum of one year of data with samples taken monthly or more frequently);

(3) At least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently;

(4) For fuels delivered in shipments or lots, the sulfur content from all shipments or lots received in a one year period; or

(5) Data from a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

(b) When a 720-hour test is used for initial qualification as pipeline natural gas, the owner or operator is required to continue sampling the fuel for hydrogen sulfide at least once per month for one year after the initial qualification period. The use of the default natural gas SO_2 emission rate under 2.3.1.1 is not allowed if any sample during the one year period has a hydrogen sulfide content greater than 0.3 gr/100 scf.

2.3.2 Natural Gas Combustion

The owner or operator may determine the SO_2 mass emissions from the combustion of a fuel that meets the definition of natural gas, in § 72.2 of this chapter, using the procedures of this section.

2.3.2.1 SO_2 Emission Rate

The owner or operator may account for SO_2 emissions either by using a default SO_2 emission rate, as determined under section 2.3.2.1.1 of this appendix, or by daily sampling of the gas sulfur content using the procedures of section 2.3.3 of this appendix. For each affected unit using a default SO_2 emission rate, the owner or operator must provide documentation that the fuel combusted is actually natural gas according to the procedures in section 2.3.2.4 of this appendix.

2.3.2.1.1 In lieu of daily sampling of the sulfur content of the natural gas, an SO_2 default emission rate may be determined using Equation D–1h. Round off the calculated SO_2 default emission rate to the nearest 0.0001 lb/mmBtu.

$$ER = H_2S \times 0.0026 \qquad \text{(Eq. D-1h)}$$

Where:

ER = Default SO_2 emission rate for natural gas combustion, lb/mmBtu.

H_2S = Hydrogen sulfide content of the natural gas, gr/100scf.

2.3.2.1.2 The hydrogen sulfide value used in Equation D–1h may be obtained from one of the following sources of information:

(a) The highest hydrogen sulfide content specified by a purchase contract or by a pipeline transportation contract;

(b) The highest hydrogen sulfide content from a certification of the gas vendor, based on routine vendor sampling and analysis (minimum of one year of data with samples taken monthly or more frequently);

(c) The highest hydrogen sulfide content from at least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently;

(d) For fuels delivered in shipments or lots, the highest hydrogen sulfide content from all shipments or lots received in a one year period; or (5) the highest hydrogen sulfide content measured during a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

2.3.2.2 Hourly Heat Input Rate

Calculate hourly heat input rate for natural gas combustion, in mmBtu/hr, using the procedures in section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.2 of this appendix in the calculations.

2.3.2.3 SO_2 Mass Emission Rate and Hourly Mass Emissions

For natural gas combustion, calculate the SO_2 mass emission rate, in lb/hr, using Equation D–5 in section 3.3.2 of this appendix, when the default SO_2 emission rate is used. Then, use the calculated SO_2 mass emission rate and the unit operating time to determine the hourly SO_2 mass emissions from natural gas combustion, in lb, using Equation D–12 in section 3.5.1 of this appendix.

2.3.2.4 Documentation that a Fuel Is Natural Gas

(a) For natural gas, provide information 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 has a hydrogen sulfide content of less than 1.0 grain/100 scf. This demonstration must be made using one of the following sources of information:

(1) The gas quality characteristics specified by a purchase contract or by a transportation contract;

(2) A certification of the gas vendor, based on routine vendor sampling and analysis (minimum of one year of data with samples taken monthly or more frequently);

(3) At least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently;

(4) For fuels delivered in shipments or lots, sulfur content from all shipments or lots received in a one year period; or

(5) Data from a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

(b) When a 720-hour test is used for initial qualification as natural gas, the owner or operator shall continue sampling the fuel for hydrogen sulfide at least once per month for one year after the initial qualification period. The use of the default natural gas SO_2 emission rate under 2.3.2.1.1 is not allowed if any sample during the one year period has a hydrogen sulfide content greater than 1.0 grain/100 scf.

2.3.3 SO_2 Mass Emissions From Any Gaseous Fuel

The owner or operator of a unit may determine SO_2 mass emissions using this section for any gaseous fuel (including fuels such as refinery gas, landfill gas, digester gas, coke oven gas, blast furnace gas, coal-derived gas, producer gas or any other gas which may have a variable sulfur content).

2.3.3.1 Sulfur Content Determination

2.3.3.1.1 Analyze the total sulfur content of the gaseous fuel in grain/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, if a demonstration is provided under section 2.3.6 of this appendix showing that the gaseous fuel has a ''low sulfur variability,'' determine the sulfur content daily using either manual sampling or a gas chromatograph; and for all other gaseous fuels, determine the sulfur content on an hourly basis using a gas chromatograph.

2.3.3.1.2 Use one of the following methods when using manual sampling (as applicable to the type of gas combusted) to determine the sulfur content of the fuel: ASTM D1072–90, ''Standard Test Method for Total Sulfur in Fuel Gases'', ASTM D4468–85 (Reapproved 1989) ''Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Radiometric Colorimetry,'' ASTM D5504–94 ''Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence,'' or ASTM D3246–81 (Reapproved 1987) ''Standard Test Method for Sulfur in Petroleum Gas By Oxidative Microcoulometry'' (incorporated by reference under § 75.6).

2.3.3.1.3 The sampling and analysis of daily manual samples may be performed by the owner or operator, an outside laboratory, or the gas supplier. If hourly sampling with a gas chromatograph is required, or a source chooses to use an online gas chromatograph to determine daily fuel sulfur content, the owner or operator shall develop and implement a program to quality assure the data from the gas chromatograph, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.3.3.1.4 Results of all sample analyses must be available no later than thirty calendar days after the sample is taken.

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 in section 3.3.1 of this appendix. Use the appropriate sulfur content, in equation D–4, as specified in Table D–5 of this appendix. That is, for fuels delivered by pipeline which demonstrate a low sulfur variability (under section 2.3.6 of this appendix) use either the daily value or the highest value in the previous 30 days or for fuels requiring hourly sulfur content sampling with a gas chromatograph use the actual hourly sulfur content).

2.3.3.3 Hourly Heat Input Rate

Calculate the hourly heat input rate for combustion of the gaseous fuel, using the provisions in section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.3 of this appendix in the calculations.

2.3.4 Gross Calorific Values for Gaseous Fuels

Determine the GCV of each gaseous fuel at the frequency specified in this section, using one of the following methods: ASTM D1826–88, ASTM D3588–91, ASTM D4891–89, GPA Standard 2172–86 ''Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis,'' or GPA Standard 2261–90 ''Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography'' (incorporated by reference under § 75.6 of this part). Use the appropriate GCV value, as specified in section 2.3.4.1, 2.3.4.2 or 2.3.4.3 of this appendix, in the calculation of unit hourly heat input rates.

2.3.4.1 GCV of Pipeline Natural Gas

Determine the GCV of fuel that is pipeline natural gas, as defined in § 72.2 of this chapter, at least once per calendar month. For GCV used in calculations use the specifications in Table D–5: either the value from the most recent monthly sample, the highest value specified in a contract or tariff sheet, or the highest value from the previous year. The fuel GCV value from the most recent monthly sample shall be used for any month in which that value is higher than a contract limit. If a unit combusts pipeline natural gas for less than 48 hours during a calendar month, the sampling and analysis requirement for GCV is waived for that calendar month. The preceding waiver is limited by the condition that at least one analysis for GCV must be performed for each quarter the unit operates for any amount of time.

2.3.4.2 GCV of Natural Gas

Determine the GCV of fuel that is natural gas, as defined in § 72.2 of this chapter, on a monthly basis, in the same manner as described for pipeline natural gas in section 2.3.4.1 of this appendix.

2.3.4.3 GCV of Other Gaseous Fuels

For gaseous fuels other than natural gas or pipeline natural gas, determine the GCV as specified in section 2.3.4.3.1, 2.3.4.3.2 or 2.3.4.3.3, as applicable. 2.3.4.3.1 For a gaseous fuel that is delivered in discrete shipments or lots, determine the GCV for each shipment or lot. The determination may be made by sampling each delivery or by sampling the supply tank after each delivery. For sampling of each delivery, use the highest GCV in the previous year's samples. For sampling from the tank after each delivery, use either the most recent GCV sample or the highest GCV in the previous year. 2.3.4.3.2 For any gaseous fuel that does not qualify as pipeline natural gas or natural gas and which is not delivered in shipments or lots which performs the required 720 hour test under section 2.3.5 of this appendix, and the results of the test demonstrate that the gaseous fuel has a low GCV variability, determine the GCV at least monthly. In calculations of hourly heat input for a unit, use either the most recent monthly sample or the highest fuel GCV from the previous year's samples. 2.3.4.3.3 For any other gaseous fuel, determine the GCV at least daily and use the actual fuel GCV in calculations of unit hourly heat input. If an online gas chromatograph or on-line calorimeter is used to determine fuel GCV each day, the owner or operator shall develop and implement a program to quality assure the data from the gas chromatograph or on-line calorimeter, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.3.5 Demonstration of Fuel GCV Variability

(a) This demonstration is required of 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 shall be used to determine whether daily or monthly sampling of the GCV of the gaseous fuel or blend is required.

(b) To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the GCV of the gaseous fuel or blend (in Btu/100 scf). The demonstration data shall be obtained using either: hourly sampling and analysis using the methods in section 2.3.4 to determine GCV of the fuel; an on-line gas chromatograph capable of determining fuel GCV on an hourly basis; or an on-line calorimeter. For gaseous fuel produced by a variable process, the data shall be representative of and include all process operating conditions including seasonal and yearly variations in process which may affect fuel GCV.

(c) The data shall be reduced to hourly averages. The mean GCV value and the standard deviation from the mean shall be calculated from the hourly averages. Specifically, the gaseous fuel is considered to have a low GCV variability, and monthly gas sampling for GCV may be used, if the mean value of the GCV multiplied by 1.075 is less than the sum of the mean value and one standard deviation. If the gaseous fuel or blend does not meet this requirement, then daily fuel sampling and analysis for GCV, using manual sampling, a gas chromatograph or an on-line calorimeter is required.

2.3.6 Demonstration of Fuel Sulfur Variability

(a) This demonstration is required for any fuel which does not qualify as pipeline natural gas or natural gas and is not delivered in shipments or lots. The results of the demonstration will be used to determine whether daily or hourly sampling for sulfur in the fuel is required. To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content (and hydrogen sulfide content, if needed to define a fuel as either pipeline natural gas or natural gas) of the gaseous fuel or blend (in gr/100 scf). The demonstration data shall be obtained using either manual hourly sampling or an on-line gas chromatograph capable of determining fuel total sulfur content (and, if applicable, H_2S content) on an hourly basis. For gaseous fuel produced by a variable process, additional data shall be provided which is representative of all process operating conditions including seasonal or annual variations which may affect fuel sulfur content.

(b) Reduce the data to hourly averages of the total sulfur content (and hydrogen sulfide content, if applicable) of the fuel. Then, calculate the mean value of the total sulfur content and standard deviation in order to determine whether daily sampling of the sulfur content of the gaseous fuel or blend is sufficient or whether hourly sampling with a gas chromatograph is required. Specifically, daily gas sampling and analysis for total sulfur content, using either manual sampling or an online gas chromatograph, shall be sufficient, provided that the standard deviation of the hourly average values from the mean value does not exceed 5.0 grains per 100 scf. If the gaseous fuel or blend does not meet this requirement, then hourly sampling of the fuel with a gas chromatograph and hourly reporting of the average sulfur content of the fuel is required.

2.4 * * *

2.4.1 Missing Data for Oil and Gas Samples

When fuel sulfur content, gross calorific value or, when necessary, density data are missing or invalid for an oil or gas sample taken according to the procedures in section 2.2.3, 2.2.4.1, 2.2.4.2, 2.2.4.3, 2.2.5, 2.2.6, 2.2.7, 2.3.3.1, 2.3.3.1.2, or 2.3.4 of this appendix, then substitute the maximum potential sulfur content, density, or gross calorific value of that fuel from Table D–6 of this appendix. Irrespective of which reporting option is selected (i.e., actual value, contract value or highest value from the previous year, 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. The substitute data value(s) shall be used until the next valid sample for the missing parameter(s) is obtained. Note that only actual sample results shall be used to determine the ''highest value from the previous year'' when that reporting option is used; missing data values shall not be used in the determination.

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 Sulfur Content	0.3 gr/100 scf for pipeline natural gas, or 1.0 gr/100 scf for natural gas, or Twice the highest total sulfur content value recorded in the previous 30 days when sampling gaseous fuel daily or hourly.
Gas GCV/Heat Content	1100 Btu/scf for pipeline natural gas, natural gas or landfill gas, or 1500 for butane or refinery gas. 2100 Btu/scf for propane or any other gaseous fuel.

2.4.2 Whenever data are missing from any fuel flowmeter that is part of an excepted monitoring system under appendix D or E to this part, where the fuel flowmeter data are required to determine the amount of fuel combusted by the unit, 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. In addition, a fuel flowmeter used for measuring fuel combusted by a peaking unit may use the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix.

2.4.2.1 Simplified Fuel Flow Missing Data 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 flowmeter can measure (i.e, upper range value of flowmeter leading to a unit).

2.4.2.2 * * *

2.4.2.3 For hours where two or more fuels are combusted, substitute the maximum hourly fuel flow rate measured and recorded by the flowmeter (or flowmeters, where fuel is recirculated) for the fuel for which data are missing at the corresponding load range recorded for each missing hour during the previous 720 hours when the unit combusted that fuel with any other fuel. For hours where no previous recorded fuel flow rate data are available for that fuel during the missing data period, calculate and substitute the maximum potential flow rate of that fuel for the unit as defined in section 2.4.2.2 of this appendix.

2.4.3 * * *

66. Appendix D to part 75 is further amended by:

a. Revising sections 3 through 3.2.1 and 3.2.3;

b. Removing section 3.2.4;

c. Revising sections 3.3 through 3.3.3;

d. Redesignating section 3.4 as 3.6 and revising the first sentence; and

e. Adding new sections 3.4 through 3.4.3 and sections 3.5 through 3.5.6 to read as follows:

3. Calculations

Calculate hourly SO_2 mass emission rate from combustion of oil fuel using the procedures in section 3.1 of this appendix. Calculate hourly SO_2 mass emission rate from combustion of gaseous fuel using the procedures in section 3.3 of this appendix. (Note: the SO_2 mass emission rates in sections 3.1 and 3.3 are calculated such that the rate, when multiplied by unit operating time, yields the hourly SO_2 mass emissions for a particular fuel for the unit.) Calculate hourly heat input rate for both oil and gaseous fuels using the procedures in section 3.4 of this appendix. Calculate total SO_2 mass emissions and heat input for each hour, each quarter and the year to date using the procedures under section 3.5 of this appendix. Where an oil flowmeter records volumetric flow rate, use the calculation procedures in section 3.2 of this appendix to calculate the mass flow rate of oil.

3.1 SO_2 Mass Emission Rate Calculation for Oil

3.1.1 Use Equation D–2 to calculate SO_2 mass emission rate per hour (lb/hr):

$$SO2_{rate\text{-}oil} = 2.0 \times OIL_{rate} \times \frac{\%S_{oil}}{100.0} \qquad \text{(Eq. D-2)}$$

Where:

$SO_{2rate\text{-}oil}$ = Hourly mass emission rate of SO_2 emitted from combustion of oil, lb/hr.

OIL_{rate} = Mass rate of oil consumed per hr during combustion, lb/hr.

$\%S_{oil}$ = Percentage of sulfur by weight measured in the sample.

2.0 = Ratio of lb SO_2/lb S.

3.1.2 Record the SO_2 mass emission rate from oil for each hour that oil is combusted.

3.2 Mass Flow Rate Calculation for Volumetric Oil Flowmeters

3.2.1 Where the oil flowmeter records volumetric flow rate rather than mass flow rate, calculate and record the oil mass flow rate for each hourly period using hourly oil flow rate measurements and the density or specific gravity of the oil sample.

* * * * *

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.6 of this appendix, use Equation D–3 to calculate the rate of the mass of oil consumed (in lb/hr):

$$OIL_{rate} = V_{oil\text{-}rate} \times D_{oil} \qquad \text{(Eq. D-3)}$$

Where:

OIL_{rate} = Mass rate of oil consumed per hr, lb/hr.

$V_{oil\text{-}rate}$ = Volume rate of oil consumed per hr, measured in scf/hr, gal/hr, barrels/hr, or m^3/hr.

D_{oil} = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m^3.

3.3 SO_2 Mass Emission Rate Calculation for Gaseous Fuels

3.3.1 Use Equation D–4 to calculate the SO_2 mass emission rate when using the optional gas sampling and analysis procedures in sections 2.3.1 and 2.3.2 of this appendix, or the required gas sampling and analysis procedures in section 2.3.3 of this appendix. Total sulfur content of a fuel must be determined using the procedures of 2.3.3.1.2 of this appendix:

$$SO2_{\text{rate-gas}} = \left(\frac{2}{7000}\right) \times GAS_{\text{rate}} \times S_{\text{gas}} \qquad \text{(Eq. D-4)}$$

Where:

$SO_{2\text{rate-gas}}$ = Hourly mass rate of SO_2 emitted due to combustion of gaseous fuel, lb/hr.
GAS_{rate} = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.
S_{gas} = 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.

3.3.2 Use Equation D–5 to calculate the SO_2 mass emission rate when using a default emission rate from section 2.3.1.1 or 2.3.2.1.1 of this appendix:

$$SO2_{\text{rate}} = ER \times HI_{\text{rate}} \qquad \text{(Eq. D-5)}$$

where:

$SO_{2\text{rate}}$ = Hourly mass emission rate of SO_2 from combustion of a gaseous fuel, lb/hr.
ER = SO_2 emission rate from section 2.3.1.1 or 2.3.2.1.1, of this appendix, lb/mmBtu.
HI_{rate} = Hourly heat input rate of a gaseous fuel, calculated using procedures in section 3.4.1 of this appendix, in mmBtu/hr.

3.3.3 Record the SO_2 mass emission rate for each hour when the unit combusts a gaseous fuel.

3.4 Calculation of Heat Input Rate

3.4.1 Heat Input Rate for Gaseous Fuels

(a) Determine total hourly gas flow or average hourly gas flow rate with a fuel flowmeter in accordance with the requirements of section 2.1 of this appendix and the fuel GCV in accordance with the requirements of section 2.3.4 of this appendix. If necessary perform the 720-hour test under section 2.3.5 to determine the appropriate fuel GCV sampling frequency.

(b) Then, use Equation D–6 to calculate heat input rate from gaseous fuels for each hour.

$$HI_{\text{rate-gas}} = \frac{GAS_{\text{rate}} \times GCV_{\text{gas}}}{10^6} \qquad \text{(Eq. D-6)}$$

Where:

$HI_{\text{rate-gas}}$ = Hourly heat input rate from combustion of the gaseous fuel, mmBtu/hr.
GAS_{rate} = Average volumetric flow rate of fuel, for the portion of the hour in which the unit operated, 100 scf/hr.
GCV_{gas} = Gross calorific value of gaseous fuel, Btu/hr.
10^6 = Conversion of Btu to mmBtu.

(c) Note that when fuel flow is measured on an hourly totalized basis (e.g. a fuel flowmeter reports totalized fuel flow for each hour), before Equation D–6 can be used, the total hourly fuel usage must be converted from units of 100 scf to units of 100 scf/hr using Equation D–7:

$$GAS_{\text{rate}} = \frac{GAS_{\text{unit}}}{t} \qquad \text{(Eq. D-7)}$$

Where:

GAS_{rate} = Average volumetric flow rate of fuel for the portion of the hour in which the unit operated, 100 scf/hr.
GAS_{unit} = Total fuel combusted during the hour, 100 scf.
t = 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).

3.4.2 Heat Input Rate From the Combustion of Oil

(a) Determine total hourly oil flow or average hourly oil flow rate with a fuel flowmeter, in accordance with the requirements of section 2.1 of this appendix. Determine oil GCV according to the requirements of section 2.2 of this appendix.

Then, use Equation D–8 to calculate hourly heat input rate from oil for each hour:

$$HI_{\text{rate-oil}} = OIL_{\text{rate}} \frac{GCV_{\text{oil}}}{10^6} \qquad \text{(Eq. D-8)}$$

Where:

$HI_{\text{rate-oil}}$ = Hourly heat input rate from combustion of oil, mmBtu/hr.
OIL_{rate} = Mass rate of oil consumed per hour, as determined using procedures in section 3.2.3 of this appendix, in lb/hr, tons/hr, or kg/hr.
GCV_{oil} = Gross calorific value of oil, Btu/lb, Btu/ton, Btu/kg.
10^6 = Conversion of Btu to mmBtu.

(b) Note that when fuel flow is measured on an hourly totalized basis (e.g., a fuel flowmeter reports totalized fuel flow for each hour), before equation D–8 can be used, the total hourly fuel usage must be converted from units of lb to units of lb/hr, using equation D–9:

$$OIL_{\text{rate}} = \frac{OIL_{\text{unit}}}{t} \qquad \text{(Eq. D-9)}$$

Where:

OIL_{rate} = Average fuel flow rate for the portion of the hour which the unit operated in lb/hr.

OIL_{unit} = Total fuel combusted during the hour, lb.
t = 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).

3.4.3 Apportioning Heat Input Rate to Multiple Units

(a) Use the procedure in this section to apportion hourly heat input rate to two or more units using a single fuel flowmeter which supplies fuel to the units. (This procedure is not applicable to units calculating NO_X mass emissions using the provisions of subpart H of this part.) The designated representative may also petition the Administrator under § 75.66 to use this apportionment procedure to calculate SO_2 and CO_2 mass emissions.

(b) Determine total hourly fuel flow or flow rate through the fuel flowmeter supplying gas or oil fuel to the units. Convert fuel flow rates to units of 100 scf for gaseous fuels or to lb for oil, using the procedures of this appendix. Apportion the fuel to each unit separately based on hourly output of the unit in MW_e or 1000 lb of steam/hr (klb/hr) using Equation D–10 or D–11, as applicable:

$$GAS_{\text{unit}} = GAS_{\text{meter}} \left(\frac{U_{\text{output}}}{\sum_{\text{all-units}} U_{\text{output}}} \right) \qquad \text{(Eq. D-10)}$$

Where:

GAS_{unit} = Gas flow apportioned to a unit, 100 scf.
GAS_{meter} = Total gas flow through the fuel flowmeter, 100 scf.
U_{output} = Total unit output, MW or klb/hr.

$$OIL_{unit} = OIL_{meter}\left(\frac{U_{output}}{\sum_{all\text{-}units} U_{output}}\right) \quad \text{(Eq. D-11)}$$

Where:

OIL_{unit} = Oil flow apportioned to a unit, lb.

OIL_{meter} = Total oil flow through the fuel flowmeter, lb.

U_{output} = Total unit output in either MW_e or klb/hr.

(c) Use the total apportioned fuel flow calculated from Equation D–10 or D–11 to calculate the hourly unit heat input rate, using Equations D–6 and D–7 (for gas) or Equations D–8 and D–9 (for oil).

3.5 Conversion of Hourly Rates to Hourly, Quarterly and Year to Date Totals

3.5.1 Hourly SO_2 Mass Emissions From the Combustion of All Fuels

Determine the total mass emissions for each hour from the combustion of all fuels using Equation D–12:

$$M_{SO2\text{-}hr} = \sum_{all\text{-}fuels} SO2_{rate\text{-}i}\, t_i \quad \text{(Eq. D-12)}$$

Where:

$M_{SO2\text{-}hr}$ = Total mass of SO_2 emissions from all fuels combusted during the hour, lb.

$SO_{2rate\text{-}i}$ = SO_2 mass emission rate for each type of gas or oil fuel combusted during the hour, lb/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).

3.5.2 Quarterly Total SO_2 Mass Emissions

Sum the hourly SO_2 mass emissions in lb as determined from Equation D–12 for all hours in a quarter using Equation D–13:

$$M_{SO2\text{-}qtr} = \frac{1}{2000}\sum_{all\text{-}hours\text{-}in\text{-}qtr} M_{SO2\text{-}hr} \quad \text{(Eq. D-13)}$$

Where:

$M_{SO2\text{-}qtr}$ = Total mass of SO_2 emissions from all fuels combusted during the quarter, tons.

$M_{SO2\text{-}hr}$ = Hourly SO_2 mass emissions determined using Equation D–12, lb.

2000= Conversion factor from lb to tons.

3.5.3 Year to Date SO_2 Mass Emissions

Calculate and record SO_2 mass emissions in the year to date using Equation D–14:

$$M_{SO2\text{-}YTD} = \sum_{q=1}^{current\text{-}quarter} M_{SO2\text{-}qtr} \quad \text{(Eq. D-14)}$$

Where:

$M_{SO2\text{-}YTD}$ = Total SO_2 mass emissions for the year to date, tons.

$M_{SO2\text{-}qtr}$ = Total SO_2 mass emissions for the quarter, tons.

3.5.4 Hourly Total Heat Input from the Combustion of all Fuels

Determine the total heat input in mmBtu for each hour from the combustion of all fuels using Equation D–15:

$$HI_{hr} = \sum_{all\text{-}fuels} HI_{rate\text{-}i}\, t_i \quad \text{(Eq. D-15)}$$

Where:

HI_{hr} = Total heat input from all fuels combusted during the hour, mmBtu.

$HI_{rate\text{-}i}$ =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).

3.5.5 Quarterly Heat Input

Sum the hourly heat input values determined from equation D–15 for all hours in a quarter using Equation D–16:

$$HI_{qtr} = \frac{1}{2000}\sum_{all\text{-}hours\text{-}in\text{-}qtr} HI_{hr} \quad \text{(Eq. D-16)}$$

Where:

HI_{qtr} = Total heat input from all fuels combusted during the quarter, mmBtu.

HI_{hr} = Hourly heat input determined using Equation D–15, mmBtu.

3.5.6 Year-to-Date Heat Input

Calculate and record the total heat input in the year to date using Equation D–17.

$$HI_{YTD} = \sum_{q=1}^{current\text{-}quarter} HI_{qtr} \quad \text{(Eq. D-17)}$$

HI_{YTD} = Total heat input for the year to date, mmBtu.

HI_{qtr} = Total heat input for the quarter, mmBtu.

3.6 Records and Reports

Calculate and record quarterly and cumulative SO_2 mass emissions and heat input for each calendar quarter using the procedures and equations of section 3.5 of this appendix. * * *

67. Appendix E to part 75 is amended by revising sections 2.4.2, 2.4.3, 2.4.4, 2.5.4 and 2.5.5 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

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2. Procedure

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2.4 Procedures for Determining Hourly NO_X Emission Rate

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2.4.2 Use the graph of the baseline correlation results (appropriate for the fuel or fuel combination) to determine the NO_X emissions rate (lb/mmBtu) corresponding to the heat input rate (mmBtu/hr). Input this correlation into the data acquisition and handling system for the unit. Linearly interpolate to 0.1 mmBtu/hr heat input rate and 0.01 lb/mmBtu NO_X (0.001 lb/mmBtu NO_X after April 1, 2000). For each type of fuel, calculate NO_X emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

2.4.3 To determine the NO_X emission rate for a unit co-firing fuels that has not been tested for that combination of fuels, interpolate between the NO_X emission rate for each fuel as follows. Determine the heat input rate for the hour (in mmBtu/hr) for each fuel and select the corresponding NO_X emission rate for each fuel on the appropriate graph. (When a fuel is combusted for a partial hour, determine the fuel usage time for each fuel and determine the heat input rate from each fuel as if that fuel were combusted at that rate for the entire hour in order to select the corresponding NO_X emission rate.) Calculate the total heat input to the unit in mmBtu for the hour from all fuel combusted using Equation E–1. Calculate a Btu-weighted average of the emission rates for all fuels using Equation E–2 of this appendix. For each type of fuel, calculate NO_X emission rate using the baseline correlation results from the most recent test with that fuel, beginning with the date and hour of the completion of the most recent test.

2.4.4 For each hour, record the critical quality assurance parameters, as identified in the monitoring plan, and as required by section 2.3 of this appendix from the date and hour of the completion of the most recent test for each type of fuel.

2.5 Missing Data Procedures

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2.5.4 Substitute missing data from a fuel flowmeter using the procedures in section 2.4.2 of appendix D to this part.

2.5.5 Substitute missing data for gross calorific value of fuel using the procedures in sections 2.4.1 of appendix D to this part.

68. Appendix E to part 75 is further amended by revising sections 3.1, 3.3.1, and 3.3.4 to read as follows:

3. Calculations

3.1 Heat Input

Calculate the total heat input by summing the product of heat input rate and fuel usage time of each fuel, as in the following equation:

$$H_T = HI_{fuel1}t_1 + HI_{fuel2}t_2 + HI_{fuel3}t_3 + \ldots + HI_{lastfuel}t_{last} \qquad \text{(Eq. E-1)}$$

Where:

H_T = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.

$HI_{fuel\ 1,2,3,\ldots last}$ = Heat input rate from each fuel, in mmBtu/hr as determined using Equation F–19 or F–20 in section 5.5 of appendix F to this part, mmBtu/hr.

$t_{1,2,3,\ldots last}$ = Fuel usage time for each fuel (rounded up to the nearest 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)).

* * * * *

3.3 * * *

3.3.1 Conversion from Concentration to Emission Rate

Convert the NO_X concentrations (ppm) and O_2 concentrations to NO_X emission rates (to the nearest 0.01 lb/mmBtu for tests performed prior to April 1, 2000, or to the nearest 0.001 lb/mmBtu for tests performed on and after April 1, 2000), according to the appropriate one of the following equations: F–5 in appendix F to this part for dry basis concentration measurements or 19–3 in Method 19 of appendix A to part 60 of this chapter for wet basis concentration measurements.

* * * * *

3.3.4 Average NO_X Emission Rate During Co-firing of Fuels

$$E_h = \frac{\sum_{f=1}^{\text{all fuels}} \left(E_f \times HI_f t_f\right)}{H_T} \qquad \text{(Eq. E-2)}$$

Where:

E_h = NO_X emission rate for the unit for the hour, lb/mmBtu.

E_f = NO_X emission rate for the unit for a given fuel at heat input rate HI_f, lb/mmBtu.

HI_f = Heat input rate for the hour for a given fuel, during the fuel usage time, as determined using Equation F–19 or F–20 in section 5.5 of appendix F to this part, mmBtu/hr.

H_T = Total heat input for all fuels for the hour from Equation E–1.

t_f = Fuel usage time for each fuel (rounded up to the nearest 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)).

Note: For hours where a fuel is combusted for only part of the hour, use the fuel flow rate or mass flow rate during the fuel usage time, instead of the total fuel flow or mass flow during the hour, when calculating heat input rate using Equation F–19 or F–20.

69. Appendix F to part 75 is amended by revising sections 2, 2.1, 2.2, 2.3, and 2.4 to read as follows:

Appendix F to Part 75—Conversion Procedures

* * * * *

2. Procedures for SO_2 Emissions

Use the following procedures to compute hourly SO_2 mass emission rate (in lb/hr) and quarterly and annual SO_2 total mass emissions (in tons). Use the procedures in Method 19 in appendix A to part 60 of this chapter to compute hourly SO_2 emission rates (in lb/mmBtu) for qualifying Phase I technologies. When computing hourly SO_2 emission rate in lb/mmBtu, a minimum concentration of 5.0 percent CO_2 and a maximum concentration of 14.0 percent O_2 may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO_2 is less than 5.0 percent CO_2 or the hourly average concentration of O_2 is greater than 14.0 percent O_2.

2.1 When measurements of SO_2 concentration and flow rate are on a wet basis, use the following equation to compute hourly SO_2 mass emission rate (in lb/hr):

$$E_h = KC_hQ_h \qquad \text{(Eq. F-1)}$$

Where:

E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.

$K = 1.660 \times 10^{-7}$ for SO_2, (lb/scf)/ppm.

C_h = Hourly average SO_2 concentration during unit operation, stack moisture basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, stack moisture basis, scfh.

2.2 When measurements by the SO_2 pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO_2 mass emission rate (in lb/hr):

$$E_h = K\,C_{hp}Q_{hs}\frac{\left(100 - \%H_2O\right)}{100} \qquad \text{(Eq. F-2)}$$

where:

E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.

$K = 1.660 \times 10^{-7}$ for SO_2, (lb/scf)/ppm.

C_{hp} = Hourly average SO_2 concentration during unit operation, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

2.3 Use the following equations to calculate total SO_2 mass emissions for each calendar quarter (Equation F–3) and for each calendar year (Equation F–4), in tons:

$$E_q = \frac{\sum_{h=i}^{n} E_h t_h}{2000} \qquad \text{(Eq. F-3)}$$

Where:

E_q = Quarterly total SO_2 mass emissions, tons.

E_h = Hourly SO_2 mass emission rate, lb/hr.

t_h = 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).
n = Number of hourly SO_2 emissions values during calendar quarter.
2000 = Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^{4} E_q \qquad \text{(Eq. F-4)}$$

Where:

E_a = Annual total SO_2 mass emissions, tons.
E_q = Quarterly SO_2 mass emissions, tons.
q = Quarters for which E_q are available during calendar year.

2.4 Round all SO_2 mass emission rates and totals to the nearest tenth.

70. Appendix F to part 75 is further amended by revising sections 3.3.2, 3.3.3, 3.3.4, 3.4, and 3.5 to read as follows:

3. Procedures for NO_X Emission Rate

* * * * *

3.3 * * *

3.3.2 E = Pollutant emissions during unit operation, lb/mmBtu.
3.3.3 C_h = Hourly average pollutant concentration during unit operation, ppm.
3.3.4 $\%O_2$, $\%CO_2$ = Oxygen or carbon dioxide volume during unit operation (expressed as percent O_2 or CO_2). A minimum concentration of 5.0 percent CO_2 and a maximum concentration of 14.0 percent O_2 may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO_2 is < 5.0 percent CO_2 or the hourly average concentration of O_2 is > 14.0 percent O_2. A minimum concentration of 1.0 percent CO_2 and a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values at stationary gas turbines during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2 or the hourly average concentration of O_2 is > 19.0 percent O_2.

* * * * *

3.4 Use the following equations to calculate the average NO_X emission rate for each calendar quarter (Equation F–9) and the average emission rate for the calendar year (Equation F–10), in lb/mmBtu:

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n} \qquad \text{(Eq. F-9)}$$

Where:

E_q = Quarterly average NO_X emission rate, lb/mmBtu.
E_i = Hourly average NO_X emission rate during unit operation, lb/mmBtu.
n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^{m} \frac{E_i}{m} \qquad \text{(Eq. F-10)}$$

Where:

E_a = Average NO_X emission rate for the calendar year, lb/mmBtu.
E_i = Hourly average NO_X emission rate during unit operation, lb/mmBtu.
m = Number of hourly rates for which E_i is available in the calendar year.

3.5 Round all NO_X emission rates to the nearest 0.01 lb/mmBtu prior to April 1, 2000, and to the nearest 0.001 lb/mmBtu on and after April 1, 2000.

71. Appendix F to part 75 is further amended by revising sections 4.1, 4.2, 4.3, 4.4, and 4.4.1 to read as follows:

4. Procedures for CO_2 Mass Emissions

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4.1 When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr):

$$E_h = KC_hQ_h \qquad \text{(Eq. F-11)}$$

Where:

E_h = Hourly CO_2 mass emission rate during unit operation, tons/hr.
K = 5.7×10^{-7} for CO_2, (tons/scf) /$\%CO_2$.
C_h = Hourly average CO_2 concentration during unit operation, wet basis, percent CO_2. For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of heat input for that hour.
Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

4.2 When CO_2 concentration is measured on a dry basis, use Equation F–2 to calculate the hourly CO_2 mass emission rate (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf) percent CO_2, where E_h = hourly CO_2 mass emission rate, tons/hr and C_{hp} = hourly average CO_2 concentration in flue, dry basis, percent CO_2.

4.3 Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation F–12) and for each calendar year (Equation F–13):

$$E_{CO_2q} = \sum_{h=1}^{H_R} E_h t_h \qquad \text{(Eq. F-12)}$$

Where:

E_{CO2q} = Quarterly total CO_2 mass emissions, tons.
E_h = Hourly CO_2 mass emission rate, tons/hr.
t_h=Unit operating time, 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).
H_R = Number of hourly CO_2 mass emission rates available during calendar quarter.

$$E_{CO_2a} = \sum_{q=1}^{4} E_{CO_2q} \qquad \text{(Eq. F-13)}$$

Where:

E_{CO2a} = Annual total CO_2 mass emission,
E_{CO2q} = Quarterly total CO_2 mass emissions, tons.
q = Quarters for which E_{CO2q} are available during calendar year.

4.4 For an affected unit, when the owner or operator is continuously monitoring O_2 concentration (in percent by volume) of flue gases using an O_2 monitor, use the equations and procedures in section 4.4.1 and 4.4.2 of this appendix to determine hourly CO_2 mass emissions (in tons).

4.4.1 Use appropriate F and F_c factors from section 3.3.5 of this appendix in one of the following equations (as applicable) to determine hourly average CO_2 concentration of flue gases (in percent by volume):

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9} \qquad \text{(Eq. F-14a)}$$

CO_{2d} = Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.
F, F_c = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.
20.9 = Percentage of O_2 in ambient air.
O_{2d} = Hourly average O_2 concentration during unit operation, percent by volume, dry basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2, provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2, provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of heat input for that hour.

$$CO_{2w} = \frac{100}{20.9}\,\frac{F_c}{F}\left[20.9\left(\frac{100-\%H_2O}{100}\right)-O_{2w}\right] \qquad \text{(Eq. F-14b)}$$

Where:
CO_{2w} = Hourly average CO_2 concentration during unit operation, percent by volume, wet basis.
O_{2w} = Hourly average O_2 concentration during unit operation, percent by volume, wet basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2, provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2, provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of heat input for that hour.
F, F_c = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.
20.9 = Percentage of O_2 in ambient air.
$\%H_2O$ = Moisture content of gas in the stack, percent.

* * * * *

72. Appendix F to part 75 is amended by revising sections 5 through 5.2.4; adding sections 5.3 through 5.3.2; revising sections 5.5, 5.5.1 and 5.5.2; and by adding new sections 5.6 through 5.6.2 and 5.7 and by removing and revising section 5.4 to read as follows:

5. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided in sections 5.5 through 5.5.7. The owner or operator may choose to use the provisions specified in § 75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided in sections 5.6 through 5.6.2 to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

5.2.1 When measurements of CO_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w\,\frac{1}{F_c}\,\frac{\%CO_{2w}}{100} \qquad \text{(Eq. F-15)}$$

Where:
HI = Hourly heat input rate during unit operation, mmBtu/hr.
Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.
F_c = Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.
$\%CO_{2w}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 wet basis. For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour.

5.2.2 When measurements of CO_2 concentration are on a dry basis, use the following equation:

$$HI = Q_h\left[\frac{(100-\%H_2O)}{100F_c}\right]\left(\frac{\%CO_{2d}}{100}\right) \qquad \text{(Eq. F-16)}$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-Factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 dry basis. For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour.

$\%H_2O$ = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{\left[(20.9/100)(100 - \%H_2O) - \%O_{2w}\right]}{20.9} \qquad \text{(Eq. F-17)}$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

$\%O_{2w}$ = Hourly concentration of O_2 during unit operation, percent O_2 wet basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2, provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2, provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour.

$\%H_2O$ = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2 concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100\ F}\right]\left[\frac{(20.9 - \%O_{2d})}{20.9}\right] \qquad \text{(Eq. F-18)}$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

$\%H_2O$ = Moisture content of the stack gas, percent.

$\%O_{2d}$ = Hourly concentration of O_2 during unit operation, percent O_2 dry basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2, provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2, provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour.

5.3 *Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)*

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{hour=1}^{n} HI_i t_i \qquad \text{(Eq. F-18a)}$$

Where:

HI_q = Total heat input for the quarter, mmBtu.

HI_i = Hourly heat input rate during unit operation, using Equation F–15, F–16, F–17, or F–18, mmBtu/hr.

t_i = Hourly operating time for the unit or common stack, 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).

5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q \qquad \text{(Eq. F-18b)}$$

Where:

HI_c = Total heat input for the year to date, mmBtu.

HI_q = Total heat input for the quarter, mmBtu.

5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2 emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_X mass emissions under a State or federal NO_X mass emission reduction program.

5.5.1(a) When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

$$HI_o = M_o \frac{GCV_o}{10^6} \qquad \text{(Eq. F-19)}$$

Where:

HI_o = Hourly heat input rate from oil, mmBtu/hr.

M_o = Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o = Gross calorific value of oil, as measured by ASTM D240–87 (Reapproved 1991), ASTM D2015–91, or ASTM D2382–88 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (incorporated by reference under § 75.6).

10^6 = Conversion of Btu to mmBtu.

(b) When performing oil sampling and analysis solely for the purpose of the missing data procedures in § 75.36, oil samples for measuring GCV may be taken weekly, and the procedures specified in appendix D to this part for determining the mass rate of oil consumed per hour are optional.

5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input rate from gaseous fuels for each hour:

$$HI_g = \frac{\left(Q_g \times GCV_g\right)}{10^6} \qquad \text{(Eq. F-20)}$$

Where:

HIg = Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q_g = Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet.

GCV_g = Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826–88, ASTM D3588–91, ASTM D4891–89, GPA Standard 2172–86 ''Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis,'' or GPA Standard 2261–90 ''Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,'' Btu/100 scf (incorporated by reference under § 75.6).

10^6 = Conversion of Btu to mmBtu.

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5.6 *Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe*

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts should apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{MW_i t_i}{\sum_{i=1}^{n} MW_i t_i}\right] \qquad \text{(Eq. F-21a)}$$

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{cs} = Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i = Gross electrical output, MWe.

t_i = Operating time at a particular unit, 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_{CS} = Operating time at common stack, 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 stack.

i = Designation of a particular unit.

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load should apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i t_i}{\sum_{i=1}^{n} SF_i t_i}\right] \qquad \text{(Eq. F-21b)}$$

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.
HI_{CS} = Heat input rate at the common stack or pipe, mmBtu/hr.
SF = Gross steam load, lb/hr.
t_i = Operating time at a particular unit, 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_{CS} = Operating time at common stack, 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 stack.
i = Designation of a particular unit.

5.7 *Heat Input Rate Summation for Units with Multiple Stacks or Pipes*

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes should sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^{n} HI_s t_s}{t_{Unit}} \qquad \text{(Eq. F-21c)}$$

Where:

HI_{Unit} = Heat input rate for a unit, mmBtu/hr.
HI_s = Heat input rate for each stack or duct leading from the unit, mmBtu/hr.
t_{Unit} = Operating time for the unit, 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 during which the unit is exhausting through the stack or duct, 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).

73. Appendix F is further amended by revising 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

The owner or operator shall use the following equation to calculate hourly SO_2 mass emissions as allowed for units with SO_2 continuous emission monitoring systems if, during the combustion of gaseous fuel that meets the definition of pipeline natural gas or natural gas in § 72.2 of this chapter, SO_2 emissions are determined in accordance with § 75.11(e)(1).

$$E_h = (ER)\ (HI) \qquad \text{(Eq. F-23)}$$

Where:

E_h = Hourly SO_2 mass emissions, lb/hr.
ER = Applicable SO_2 default emission rate from section 2.3.1.1 or 2.3.2.1.1 of appendix D to this part, lb/mmBtu.
HI = Hourly heat input, as determined using the procedures of section 5.2 of this appendix.

74. Appendix F is further amended by correcting section 8 to read as follows:

8. Procedures for NO_X Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_X mass emissions under a State or federal NO_X mass emission reduction program must use the procedures in section 8.1, 8.2, or 8.3, as applicable, to account for hourly NO_X mass emissions, and the procedures in section 8.4 to account for quarterly, seasonal, and annual NO_X mass emissions to the extent that the provisions of subpart H of this part are adopted as requirements under such a program.

75. Appendix G to part 75 is amended by revising the paragraph defining the term ''W_c'' that follows Equation G–1 and by revising the paragraph defining the term ''Fc'' that follows Equation G–4 to read as follows:

Appendix G to Part 75—Determination of CO_2 Emissions

* * * * *

2. Procedures for Estimating CO_2 Emissions From Combustion

* * * * *

2.1 * * *

(Eq. G–1)

Where:

* * * * *

W_c = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates. Collect at least one fuel sample during each week that the unit combusts coal, one sample per each shipment or delivery for oil and diesel fuel, one fuel sample for each delivery for gaseous fuel in lots, one sample per day or per hour (as applicable) for each gaseous fuel that is required to be sampled daily or hourly for gross calorific value under section 2.3.5.6 of appendix D to this part, and one sample per month for each gaseous fuel that is required to be sampled monthly for gross calorific value under section 2.3.4.1 or 2.3.4.2 of appendix D to this part. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week. Determine the carbon content of each fuel sampling using one of the following methods: ASTM D3178–89 or ASTM D5373–93 for coal; ASTM D5291–92 ''Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants,'' ultimate analysis of oil, or computations based upon ASTM D3238–90 and either ASTM D2502–87 or ASTM D2503–82 (Reapproved 1987) for oil; and computations based on ASTM D1945–91 or ASTM D1946–90 for gas. Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. (All ASTM methods are incorporated by reference under § 75.6.) Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

* * * * *

2.3 * * *

(Eq. G–4)

Where:

* * * * *

F_c = Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1,240 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.

* * * * *

76. Appendix G to part 75 is amended by adding new sections 5 through 5.3 to read as follows:

5. Missing Data Substitution Procedures for Fuel Analytical Data

Use the following procedures to substitute for missing fuel analytical data used to calculate CO_2 mass emissions under this appendix.

5.1 *Missing Carbon Content Data Prior to 4/1/2000*

Prior to April 1, 2000, follow either the procedures of this section or the procedures of section 5.2 of this appendix to substitute for missing carbon content data. On and after April 1, 2000, use the procedures of section 5.2 of this appendix to substitute for missing carbon content data, not the procedures of this section.

5.1.1 Most Recent Previous Data

Substitute the most recent, previous carbon content value available for that fuel type (gas, oil, or coal) of the same grade (for oil) or rank (for coal). To the extent practicable, use a carbon content value from the same fuel supply. Where no previous carbon content data are available for a particular fuel type or rank of coal, substitute the default carbon content from Table G–1 of this appendix.

5.1.2 [Reserved]

5.2 Missing Carbon Content Data On and After 4/1/2000

Prior to April 1, 2000, follow either the procedures of this section or the procedures of section 5.1 of this appendix to substitute for missing carbon content data. On and after April 1, 2000, use the procedures of this section to substitute for missing carbon content data.

5.2.1 In all cases (i.e., for weekly coal samples or composite oil samples from continuous sampling, for oil samples taken from the storage tank after transfer of a new delivery of fuel, for as-delivered samples of oil, diesel fuel, or gaseous fuel delivered in lots, and for gaseous fuel that is supplied by a pipeline and sampled monthly, daily or hourly for gross calorific value) when carbon content data is missing, report the appropriate default value from Table G–1.

5.2.2 The missing data values in Table G–1 shall be reported whenever the results of a required sample of fuel carbon content are either missing or invalid. The substitute data value shall be used until the next valid carbon content sample is obtained.

TABLE G–1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Sampling technique/frequency	Missing data value
Oil and coal carbon content	All oil and coal samples, prior to April 1, 2000	Most recent, previous carbon content value available for that grade of oil, or default value, in this table.
Gas carbon content	All gaseous fuel samples, prior to April 1, 2000.	Most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this table.
Default coal carbon content	All, on and after April 1, 2000	Anthracite: 90.0 percent. Bituminous: 85.0 percent. Subbituminous/Lignite: 75.0 percent.
Default oil carbon content	All, on and after April 1, 2000	90.0 percent.
Default gas carbon content	All, on and after April 1, 2000	Natural gas: 75.0 percent. Other gaseous fuels: 90.0 percent.

5.3 Gross Calorific Value Data

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO_2 emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of appendix D to this part.

Appendix H to Part 75—Revised Traceability Protocol No. 1

77. Appendix H to part 75 is removed and reserved.

Appendix J to Part 75—Compliance Dates for Revised Recordkeeping Requirements and Missing Data Procedures

78. Appendix J to part 75 is removed and reserved.

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