ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72 and 75

[FRL–6007–8]

RIN 2060–AG46

Acid Rain Program; Continuous Emission Monitoring Rule Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed 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 proposed rule benefit the environment by preventing the serious, adverse effects of acidic deposition on natural resources, ecosystems, materials, visibility, and public health. The program does this by setting emissions limitations to reduce the acidic deposition precursor emissions of sulfur dioxide and nitrogen oxides. On January 11, 1993, the Agency promulgated final rules, including the final continuous emission monitoring (CEM) rule, under title IV. On May 17, 1995, the Agency published direct final and interim rules to make the implementation of the CEM rule simpler. Subsequently, on November 20, 1996, the Agency published a final rule in response to public comments received on the direct final and interim rules.

These proposed revisions to the CEM rule would make a number of further minor changes to make the implementation of the CEM rule simpler, more streamlined, and more efficient for both EPA and the facilities affected by the rule. Furthermore, the proposed revisions would provide reduced monitoring burdens for affected facility units with low mass emissions. In addition, the proposed revisions would establish quality assurance requirements for moisture monitoring systems and add a new flow monitor quality assurance test to assure the accuracy of data reported from these types of monitoring systems. Finally, the proposed revisions would create a new monitoring option, the F-factor/fuel flow method, for certain units.

DATES: *Comments.* All public comments must be received on or before July 20, 1998.

Public Hearing. Anyone requesting a public hearing must contact EPA no later than May 31, 1998. If a hearing is held, it will take place June 8, 1998, beginning at 10:00 a.m.

ADDRESSES: *Comments.* Comments must be mailed (in duplicate if possible) to: EPA Air Docket (6102), Attention: Docket No. A–97–35, Room M–1500, Waterside Mall, 401 M Street, SW, Washington, DC 20460.

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

Docket. Docket No. A–97–35, containing supporting information used to develop the proposal is available for public inspection and copying from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section at the above address.

FOR FURTHER INFORMATION CONTACT: Jennifer Macedonia, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460, telephone number (202) 564–9123 or the Acid Rain Hotline at (202) 564–9620. Electronic copies of this notice and technical support documents can be accessed through the Acid Rain Division website at http://www.epa.gov/acidrain.

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

I. Regulated Entities

Entities potentially 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, today's proposal could potentially affect other industries. The proposal includes 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 and turbines from a wide range of industries.

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 criteria in §§ 72.6, 72.7, and 72.8 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 the Proposed 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 3590–3766). Technical corrections were published on June 23, 1993 (58 FR 34126) and July 30, 1993 (58 FR 40746–40752). A notice of direct final rulemaking and of interim final rulemaking further amending the regulations was 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 59142–59166) .

The issues addressed by this proposed rule are: (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 of the applicability provisions in Part 72; (3) new excepted methodologies for units with low mass emissions; (4) new QA/QC requirements for moisture monitoring systems; (5) clarifying changes to the certification and recertification process; (6) substitute data requirements for CO_2 and heat input, as well as a prohibition against low data availability; (7) clarifying revisions to the petition provisions for alternatives to part 75 requirements; (8) NO_X mass monitoring provisions provided as a model for adoption by state, tribal, or federal NO_X mass reduction programs; (9) clarifying changes to span and range requirements; (10) clarifying revisions to general QA/QC requirements; (11) calibration gas concentrations for daily calibration error tests; (12) linearity test requirements; (13) a new flow-to-load QA test for flow monitors; (14) reductions in and/or clarifications to the relative accuracy test audit (RATA) and bias test requirements; (15) clarifying revisions to the procedures for CEM data validation; (16) clarifying revisions to the SO_2 emissions data protocol for gas-fired and oil-fired units (Appendix D); (17) determining CO_2 emissions (Appendix G, sections 2.1 and 5); (18) recordkeeping and reporting changes to reflect the proposed revisions; (19) a revised traceability protocol (Appendix H); and (20) a new optional F-factor/fuel flow method (Appendix I). In addition, the preamble also includes a discussion on potential provisions to allow for the use of predictive emissions modeling systems (PEMS) as an alternative to CEMS for certain units.

Many of the changes proposed today are minor technical revisions based on comments received from utilities following the initial implementation of part 75. Based on experience gained in the early years of the program, utilities have developed a number of suggestions that EPA believes would simplify and streamline the monitoring process without sacrificing data quality. In addition, the Agency is proposing to reduce the monitoring requirements for units with low mass emissions to reduce burdens on those types of units and to add new monitoring options for some units. The Agency has also proposed new quality assurance requirements based on gaps identified by EPA during evaluation of the initial implementation of part 75. Finally, several minor technical changes are also proposed in order to maintain uniformity within the rule itself and to clarify various provisions.

III. Detailed Discussion of Proposed Revisions

A. Use of Projections in the Definitions of Gas-Fired, Oil-Fired, and Peaking Unit

Background

Section 72.2 of the January 11, 1993 rule provides definitions for the terms ''gas-fired,'' ''oil-fired,'' and ''peaking unit.'' Each definition provides a limit on the fuel usage or capacity factor averaged over a three year period, as well as an individual limit on each of the three years, in order to qualify under the definition. The May 17, 1995 revisions to part 75 amended those definitions by adding provisions for how a unit would initially qualify to meet the definition. Each definition provides for the case where a unit has three years of historical data demonstrating qualification, as well as the case where a unit does not have data for one or more of the three previous years (e.g., a new unit or a unit that has been in an extended shutdown). In addition, the gas-fired definition provides for the case where a unit's fuel usage is projected to change on or before January 1, 1995 and the peaking unit definition provides for the case where a unit's capacity factor is projected to change on or before the certification deadline (either 1995 or 1996) for NO_X

monitoring in § 75.4. In each case where historical data does not exist or is not representative based on projected change, the amended definitions set provisions for allowing projections of unit operation to be used in place of historical data in order to meet the criteria of the respective definition. However, none of the three definitions provides for the case where a unit's fuel usage or capacity factor is expected to change after initial classification.

Under the existing rule, the importance of determining whether a unit qualifies under the definitions of gas-fired, oil-fired, and peaking unit, centers on the differences in regulatory requirements and options for different classifications of units. For example, under § 75.11(d)(2), a unit that qualifies as gas-fired or oil-fired has an additional option for monitoring SO_2 emissions using the excepted protocol of Appendix D, in lieu of an SO_2 CEMS and flow monitor. Additionally, under § 75.14(c), a unit that qualifies as gas-fired is exempt from opacity monitoring, and, under section 2.3 of Appendix G to part 75, a gas-fired unit has an additional option for determining CO_2 mass emissions in lieu of a CO_2 CEMS or using carbon sampling in conjunction with a fuel flowmeter. Qualifying under the definition of peaking unit also has the advantage of allowing additional regulatory options. For example, a peaking unit has the option of monitoring NO_X emission rate using the excepted protocol under Appendix E, in lieu of a NO_X CEMS. Further, under section 2.3.1 of Appendix B to part 75, a peaking unit is required to perform annual quality assurance flow monitor RATAs at a single load level instead of at three load levels.

Utility representatives have contacted EPA for guidance about how a change in the manner of operation of the unit after certification and initial classification of the unit affects the status of the unit with respect to the definitions of gas-fired, oil-fired, and peaking unit. For example, a utility representative contacted the Agency about a unit designed to burn gas and/or oil that historically had burned primarily oil and was classified as an oil-fired unit. The utility had decided to switch from oil to burn almost entirely gas at the unit and asked whether it was necessary to wait three years after the switch to gas in order to gather three years of historical data, to qualify for the additional regulatory options available only for gas-fired units. The utility requested permission to use projections of fuel usage certified by the designated representative, to demonstrate that the unit would meet the gas-fired definition after the switch to gas, so that the unit could be exempt from opacity monitoring and qualify to use equation G–4 to determine CO_2 mass emissions. The existing rule would require such a unit to wait three years after the change in operation in order to qualify as gas-fired. Based on EPA's experience of implementing the provisions of Parts 72 and 75, the definitions of the terms gas-fired, oil-fired, and peaking unit are not sufficiently detailed or flexible to address situations where a permanent change in the manner of operation after the initial classification (i.e, capacity factor or fuel usage) affects the gas-fired, oil-fired, or peaking unit status.

Discussion of Proposed Changes

Today's proposal would amend the definitions of the terms gas-fired, oil-fired, and peaking unit, to add provisions for an existing unit that does not presently qualify under the definition but that experiences a permanent change in operation (i.e., fuel usage for the gas-and oil-fired definitions and capacity factor for the peaking unit definition).

For the definition of gas-fired, the proposed revisions would allow an existing unit to qualify under the definition if the designated representative submits a minimum of 720 hours of unit operating data demonstrating that the unit meets the percentage criteria of a gas-fired unit (i.e., no less than 90.0 percent of the unit's heat input from the combustion of gaseous fuels with a total sulfur content no greater than natural gas and the remaining heat input from the combustion of fuel oil), accompanied by a certification statement from the designated representative. The designated representative statement would certify that the changed pattern of fuel usage, represented in the 720 hours of data, is considered permanent and is projected to continue for the foreseeable future.

The proposed definition of oil-fired unit would simplify the provisions for qualification, for purposes of part 75. The proposed definition would simply require that a unit burn only fuel oil and gaseous fuels with a total sulfur content no greater than natural gas and that the unit does not meet the definition of gas-fired, in order to qualify as oil-fired. With this simplification, a unit could qualify under any of the following circumstances: (1) a new unit projected to burn only fuel oil and gaseous fuels with a sulfur content no greater than natural gas but projected to burn too much oil to qualify as gas-fired; (2) an existing gas-fired unit, which burns only fuel oil and natural gas, but which exceeds the gas-fired annual limit of 15 percent of the annual heat input from fuel oil; and (3) an existing coal-fired unit that is converted to only burn fuel oil and/or gas but which projects it will burn too much oil to qualify as gas-fired.

The proposed definition of peaking unit would allow an existing unit whose capacity factor is projected to change, to qualify as a peaking unit if the designated representative submits a demonstration satisfactory to the Administrator that the unit will qualify as a peaking unit, using the three calendar years beginning with the first full year following the change in the unit's capacity factor as the three year period. This demonstration would need to show that the unit's capacity factor in the year following the permanent change in operation did not exceed 10.0 percent and that the projected average annual capacity factor for the unit in the three year period and the projected capacity for each of the two individual projected years will meet the definition of a peaking unit.

Additionally, under today's proposal, the gas-fired definition would be revised to clarify the requirements as they apply for the purposes of part 75 versus the requirements for the purposes of all other Parts under the Acid Rain Program. This proposed revision is merely editorial and would not change the intent of the existing regulation.

Rationale

The Agency proposes to allow projections of fuel usage or capacity factor in conjunction with some actual data to be used for the purpose of meeting the criteria of the gas- or oil-fired or peaking unit definitions, respectively. The Agency believes it is unnecessary to require three years to pass before a unit that the designated representative certifies has permanently changed its manner of operation is allowed to utilize the additional regulatory options allowed for units meeting the definitions of gas-fired, oil-fired, and peaking unit. The Agency believes it is sufficient to require the designated representative to submit representative data that the unit would qualify under the definition following the permanent change in operation or fuel usage (i.e., 720 hours for the gas-fired definition and a full year for the peaking unit definition) and to certify that the change in fuel usage or capacity factor is considered permanent and that the unit is expected to continue to meet the definition of gas-fired, oil-fired, or peaking unit, as applicable, into the foreseeable future.

Under the existing rule, the peaking unit definition does provide for the situation where a unit's operation is projected to change and the unit will meet the peaking unit definition with those projections. However, this provision is limited to the case where a unit's operation has changed by the certification deadline for NO_X monitoring. The existing rule does not provide for the scenario where a change to the unit's operation after the certification deadline would affect the peaking unit status and where the designated representative might want to take advantage of regulatory options that are available under this new status.

EPA believes that it is appropriate to allow a unit to use the regulatory options that are only allowed for peaking units, if a unit's operation permanently changes such that it meets the capacity factor definition with one year of actual data and two years of projections. If the projections are incorrect, the unit will lose its peaking unit status and will not be able to use projections again to qualify.

Similarly, under the existing rule, the gas-fired definition does provide for the situation where an existing unit that does not qualify under the gas-fired definition experiences a change in operations or fuel usage that would result in the unit qualifying as gas-fired in future years. However, this provision is limited to the case where a unit's operation has changed by the certification deadline for SO_2 and opacity monitoring, from 1995 through 1997. The existing rule does not provide for the scenario where a change to the unit's fuel usage after the certification deadline would affect the gas-fired status and that the designated representative might want to take advantage of regulatory options that are available under this new status.

However, EPA believes that it is appropriate to allow a unit to use the regulatory options that are only allowed for gas-fired units, if a unit's fuel usage permanently changes such that it meets the gas-fired definition with 720 hours of actual data and projections of fuel usage to make up the remainder of the three year period. If the projections are incorrect, the unit will lose its gas-fired status and will not be able to use projections again to qualify.

B. Wording Correction of the Applicability Provisions in Part 72

Background

Section 72.6(b)(1) currently includes, in the list of types of units that are unaffected units under the Acid Rain Program, ''[a] simple combustion turbine that commenced operation before November 15, 1990.'' 40 CFR 72.6(b)(1). Title IV actually provides, through statutory definitions and provisions setting emission limitations, that a simple combustion turbine that commenced *commercial* operation before the enactment of title IV, i.e., November 15, 1990, is an unaffected unit. A simple combustion turbine commencing commercial operation on or after November 15, 1990 is an affected unit (unless it is exempt under some other provision, e.g., the new units exemption under § 72.7).

To begin, the definition of ''existing unit'' in section 402(8) of the Act excludes existing simple combustion turbines (i.e., those that commenced commercial operation prior to November 15, 1990) and so excludes them from being affected units subject to an SO_2 emission limitation under section 405(a)(1). As stated in that section 402(8):

> ''existing unit'' means a unit * * * that commenced commercial operation before the date of enactment of the Clean Air Act Amendments of 1990 [i.e., November 15, 1990] * * * For purposes of this title, existing units shall not include simple combustion turbines * * * 42 U.S.C. 7651a(8).

In contrast, the statutory definition of ''new unit'' does not exclude any new simple combustion turbines, and under section 403(e), all new utility units are affected units subject to an SO_2 emission limitation. As stated in section 402(10):

> ''new unit'' means a unit that commences commercial operation on or after the date of enactment of the Clean Air Act Amendments of 1990 [i.e., November 15, 1990]. 42 U.S.C. 7651a(10).

A unit that commences commercial operation *after* November 15, 1990, and so does not meet the definition of ''existing unit'', is therefore a new unit and an affected unit subject to Acid Rain Program requirements.

While § 72.6(b)(1) states that a simple combustion turbine that ''commenced operation'' before November 15, 1990 is not an affected unit, EPA interprets this provision, consistent with the Act, to refer to commencement of commercial operation. However, in order to remove any ambiguity and any possibility of erroneous application of the statutory exemption for simple combustion turbines, EPA believes that the regulatory provision should be corrected.

Discussion of Proposed Changes

Today's proposal would revise the existing § 72.6(b)(1) in order to make it consistent with title IV of the Act. EPA proposes to revise the language of the provision to refer expressly to ''commercial operation,'' rather than simply ''operation,'' of a simple combustion turbine.

Rationale

EPA notes that the existing § 72.6(b)(1) was not intended to deviate from the provisions in the Act concerning simple combustion turbines. In proposing the applicability provisions that were finalized (with changes) as § 72.6, EPA explained that:

> simple combustion turbines would be subject to Acid Rain Program requirements in Phase II (as new units) if such units commenced commercial operation on or after November 15, 1990, because the statutory exemption for simple combustion turbines is only applicable to existing units. 56 FR 63002, 63008 (1991).

In noting that new simple combustion turbines are affected units, EPA requested comment on whether a ''*de minimis* exclusion should be included in the final rule'' for ''very small units'' from the Acid Rain Program. *Id.* In response to comments supporting an exemption for simple combustion turbines and other units, EPA established in the final rule an exemption for new units (including new simple combustion turbines) serving generators with total capacity of 25 MWe or less. 58 FR 3590, 3593–4 (1993); Response to Comment at P–22 and P–23 (1993). In the final rule preamble, EPA did not indicate any intention to make any other changes concerning the applicability of the Acid Rain Program to new simple combustion turbines.

C. Low Mass Emissions Excepted Methodology

Background

In the January 11, 1993 Acid Rain permitting rule, EPA provided for a conditional exemption from the emissions reduction, permitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05 percent by weight, because of the *de minimis* nature of their emissions (see 58 FR 3593–94 and 3645–46). Moreover, in the January 11, 1993 monitoring rule, EPA allowed gas-fired and oil-fired peaking units to use the provisions of Appendix E, instead of CEMS, to determine the NO_X emission rate, stating that this was a *de minimis* exception. EPA allowed this exception from the requirements of section 412 of the Clean Air Act because the NO_X emissions from these units would be extremely low, both collectively and individually, and because the cost of measuring a ton of NO_X with CEMS could be several hundred dollars per ton of NO_X monitored (see 58 FR 3644–45). One utility wrote to the Agency, suggesting that the Agency consider further regulatory relief for other units with extremely low emissions that do not fall under the categories of small new units burning fuels with a sulfur content less than or equal to 0.05 percent by weight or gas-fired and oil-fired peaking units (see Docket A–97–35, Item II–D–31). The utility specifically suggested that the Agency consider an exemption, the ability to use Appendix E, or some other simplified methods which are more cost effective.

In the process of implementing part 75, other utilities also have suggested to EPA that it provide regulatory relief to low mass emitting units (see Docket A–97–35, Items II–D–29, II–E–25). These units might be low mass emitting because they use a clean fuel, such as natural gas, and/or because they operate relatively infrequently. Some utilities stated that they spend a great deal of time reviewing the emissions data when preparing quarterly reports for these units. Others indicated that it would be important to reduce monitoring and quality assurance (QA) requirements in order to save time and money currently devoted to units with minimal emissions (see Docket A–97–35, Item II–E–25).

Discussion of Proposed Changes

Today's proposal would incorporate optional reduced monitoring, quality assurance, and reporting requirements into part 75 for units that burn only natural gas or fuel oil, emit no more than 25 tons of SO_2 and no more than 25 tons of NO_X annually, and have calculated annual SO_2 and NO_X emissions (reflecting their potential emissions during actual operation) that do not exceed such limits.

A unit would initially qualify for the reduced requirements by demonstrating to the Administrator's satisfaction that the unit meets the applicability criteria in proposed § 75.19(a). Proposed § 75.19(a) would require facilities to submit historical actual (or projections, as described below) and calculated emissions data from the previous three calendar years demonstrating that a unit falls below the 25-ton cutoffs for SO_2 and NO_X. The calculated emissions data for the previous three calendar years would be determined by applying the emission factors and maximum rated hourly heat input, under § 75.19(c), to the hours of operation and fuel burned during the previous three calendar years. The data demonstrating that a unit meets the applicability requirements of § 75.19(a) would be submitted in a certification application for approval by the Administrator to use the low mass emissions excepted methodology. The Agency requests comments on whether a unit that exceeded the 25-ton emissions cutoff for a part of the previous three years, but that has made a permanent change in the operation of the unit such that it would expect to meet the applicability criteria based on projections of future operation, should be allowed to use the excepted methodology.

For units that lack historical data for one or more of the previous three calendar years (including new units that lack any historical data), proposed § 75.19(a) would require the facility to provide (1) any historical emissions and operating data, beginning with the unit's first calendar year of commercial operation, that demonstrates that the unit falls under the 25-ton cutoffs for SO_2 and NO_X, both with actual emissions and with calculated emissions using the proposed methodology, as described above; and (2) a demonstration satisfactory to the Administrator that the unit will continue to emit below the tonnage cutoffs (e.g., for a new unit, applying the emission rates and hourly heat input, under § 75.19(c), to a projection of annual operation and fuel usage to determine the projected mass emissions).

For units with historical actual (or projections, as described above) emissions and calculated emissions falling below the tonnage cutoffs, facilities would be allowed to use the optional methodology in proposed § 75.19(c) in lieu of either CEMS or, where applicable, in lieu of the excepted methods under Appendix D, E, or G for the purpose of determining and reporting heat input, NO_X emission rate, and NO_X, SO_2, and CO_2 mass emissions. Under the optional methodology in proposed § 75.19(c), a facility would calculate and report hourly SO_2 and CO_2 mass emissions based on the unit's maximum rated hourly heat input and the appropriate emission factor, defined in § 75.19(c), Tables 1a and 1c, for the fuel burned that hour. Similarly, a facility would calculate and report hourly NO_X mass emissions as the product of the maximum rated hourly heat input and the appropriate fuel and boiler type NO_X emission rate located in proposed Table 1b. The facility would no longer be required to keep monitoring equipment installed on low mass emissions units, nor would it be required to meet the quality assurance test requirements or QA/QC program requirements of Appendix B to part 75. Moreover, emissions reporting requirements would be reduced by requiring only that the facility report the unit's hourly mass emissions of SO_2, CO_2, and NO_X, the unit's NO_X emission rate, and the fuel type burned for each hour of operation, and report the quarterly total and year-to-date cumulative mass emissions, heat input, and operating time, in addition to the unit's quarterly average and year-to-date average NO_X emission rate for each quarter. Facilities would continue to be required to monitor, record, and report opacity data for oil-fired units, as specified under §§ 75.14(a), 75.57(f), and 75.64(a)(iii) respectively. Under § 75.14(c) and (d), however, gas-fired, diesel-fired, and dual-fuel reciprocating engine units would continue to be exempt from opacity monitoring requirements.

If an initially qualified unit were subsequently to burn fuel other than natural gas or fuel oil, the unit would be disqualified from using the reduced requirements starting the first date on which the fuel (other than natural gas or fuel oil) was burned.

In addition, if an initially qualified unit were to subsequently exceed the 25-ton cutoff for either SO_2 or NO_X while using the proposed methodology, the facility would no longer be allowed to use the reduced requirements in proposed § 75.19(c) for determining the affected unit's heat input, NO_X emission rate, or SO_2, CO_2, and NO_X mass emissions. Proposed § 75.19(b) would allow the facility two quarters from the end of the quarter in which the exceedance of the relevant 25-ton cutoff(s) occurred to install, certify, and report SO_2, CO_2, and NO_X data from a monitoring system that meets the requirements of §§ 75.11, 75.12, and 75.13, respectively.

Rationale

In addressing concerns from utilities about the cost of monitoring, quality assurance testing, and reporting emissions from low-emitting sources, EPA considered how to establish reduced requirements. Utilities have indicated to EPA that it would be more helpful for the Agency to reduce testing requirements for monitoring equipment than it would be to reduce only reporting requirements (see Docket A–97–35, Item II–E–25). The Agency considered whether a reduction in monitoring or reporting requirements might have unintended adverse consequences for the environment. In order to minimize this possibility, but still make the program more cost effective for facilities, the Agency is proposing to allow an exception from full monitoring and reporting requirements for low mass emitting units. In proposing these reduced requirements, the Agency is exercising its discretion to allow *de minimis* exceptions from statutory requirements in administering the Clean Air Act (see, e.g., *Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360–61 (D.C. Cir. 1979); and 58 FR 3593–94 and 3645–46). The Agency, in exercising its discretion, believes that in light of the *de minimis* aggregate amount of emissions from low-emitting units as a group, little or no environmental benefit would be derived from continuing to require the additional accuracy of monitoring data from low-emitting units under the existing regulations, if such units are subjected instead to the proposed optional requirements. EPA also notes that any such benefit would be greatly outweighed by the cost of providing the more accurate data.

In drafting today's proposal, the Agency considered six relevant questions: (1) What parameters should the applicability criteria be based on? (2) How should estimated emissions be calculated? (3) What cutoff emission level should be used to determine applicability of the reduced requirements? (4) What should the on-going applicability requirements be? (5) What should the reduced monitoring and quality assurance requirements be for these units? and (6) What should the recordkeeping and reporting requirements be for these units?

1. Applicability Criteria

The Agency believes that the initial criteria for a unit to qualify for the excepted monitoring should be consistent with the on-going criteria for using such monitoring so that only units that can likely continue to use the methodology will qualify in the first place. With the reduced monitoring requirements under this exception, a unit will not need to install monitors. Consequently, the Agency believes that the on-going applicability criteria should not depend on measurements from emissions monitoring equipment and that actual emissions data or actual heat input data, which are measured by the monitoring equipment, would not be appropriate as the primary applicability criteria for initial qualification for the exception or as the criteria for on-going qualification.

The Agency considered what criteria, other than actual measurements, should be used as a basis for determining applicability to use the reduced monitoring and reporting exception. EPA considered various parameters to use in the applicability criteria, including: estimated emissions or heat input, the fuel burned, the unit capacity factor, and annual generation measured in MW-hr. Because the Agency's objectives for the exception include ensuring that the total emissions from the group of units that would qualify under the exception are *de minimis* and allowing more cost effective monitoring for units in such a group, the Agency believes it would be preferable to base the applicability on estimated emissions. While it may be simpler to base qualification for reduced monitoring *solely* on the fuel burned, the unit capacity factor, or the annual generation than to estimate the emissions, the Agency believes that it would be more difficult under that approach to ensure that total emissions that qualify under the exception were *de minimis*. The Agency further believes that using any of the other parameters, while attempting to ensure that the total emissions from the group are *de minimis,* might exclude some units that actually have low emissions. For example, a unit that burns mostly natural gas with emergency oil would be excluded from an exception limited to units that burn only natural gas. The Agency believes that an applicability criteria based on emissions would relate more directly to the objectives behind the optional exception than would other operating factors that might serve as a proxy for emissions.

2. Method for Determining Emissions

The Agency considered several methods for determining the estimated emissions as the basis for applicability of the reduced monitoring and reporting excepted methodology. For each of the methods considered, rather than using actual measured sulfur and carbon values, CO_2, SO_2, and flow CEM readings, NO_X CEM readings, or NO_X values from an Appendix E NO_X-versus-heat input correlation, a facility would calculate the unit's emissions based on an emission rate factor and default heat input. Since the units that would qualify for the excepted methodology would still be accountable for reporting emissions to the Agency and surrendering allowances based on those emissions, where applicable, the emissions estimations would not just be used to determine if the unit qualifies under the exception; the reported estimations would also be used to determine compliance. The Agency considered its goals for emissions accounting in order to establish the emission rate factors and default heat input. The Agency maintains that it would be inappropriate to select values that would potentially underestimate emissions, thereby undermining the Agency's ability to determine compliance and achieve emission reductions under title IV or any other regulatory program involving SO_2, CO_2, or NO_X. Some industry representatives suggested that facilities would be willing to use a conservative emission estimate, such as a maximum potential emission rate times the maximum heat input, if it would allow them to save time and money currently spent on monitoring and quality assurance (see Docket A–97–35, Items II–D–30, II–D–43, II–D–45, II–E–13, and II–E–25).

The Agency explored basing the estimated emissions on a unit's maximum potential emissions, i.e., converting the unit's nameplate capacity (which assumes maximum possible operation) to a maximum annual heat input for the unit and multiplying by the unit's maximum emission rate (which assumes the highest emission rate of all fuels capable of being burned at the unit). This option would have several advantages. It would ensure that emissions are not underestimated, would allow for reduced monitoring requirements, and would ensure that a unit that initially qualifies for the exception would continue to qualify without having to reevaluate the unit's emissions each year (unless some modification was made to the unit to increase its nameplate capacity or allow a higher emitting fuel to be burned). This approach, however, would likely disqualify gas-fired units that sometimes burn oil or peaking units that operate infrequently, since maximum potential emissions would be substantially higher than their actual emissions and would likely exceed the applicability criteria limit. Using this method to estimate emissions for purposes of an applicability cutoff would greatly diminish the usefulness of the reduced requirements and would fail to fully meet the intended purpose of today's proposal.

In place of using a heat input derived from maximum possible operation (i.e., nameplate capacity), the Agency considered estimating heat input by multiplying the actual operating hours times a maximum rated hourly heat input for the unit. While this would require re-evaluation of a unit's eligibility each year, this would allow an infrequently operated peaking unit to qualify if its emissions are low, which EPA believes is worth the additional burden of annual re-evaluation. Therefore, the Agency is proposing to use maximum rated hourly heat input as the heat input in the emissions estimation. Maximum rated hourly heat input would be defined, in § 72.2, as a unit-specific maximum hourly heat input (mmBtu) based on the manufacturer's rating of the unit or, if that value has been exceeded in practice, based on the highest observed hourly heat input. In addition, there would be provisions for a lower maximum hourly heat input to be used if the unit has undergone modifications which permanently limit its capacity.

The Agency also considered what emission rate(s) to apply, instead of using the highest emission rate of all fuels capable of being burned at the unit, in order to avoid underestimation and to allow a unit that primarily burns gas but has the ability to burn oil to qualify for the reduced requirements. The Agency believes that it would be appropriate to use emission rates based on uncontrolled emissions for the actual fuel burned in any given hour to estimate emissions for purposes of the initial and on-going applicability cutoffs to qualify to use the low mass emissions excepted methodology and for purposes of emissions reporting, allowance accounting, and compliance. This approach would avoid disqualifying gas-fired units simply because of their occasional use of oil and would also avoid underestimating emissions.

For determining SO_2 mass emissions using the low mass emissions methodology, EPA proposes the use of emission factors in lb/mmBtu based on its AP–42 air pollution emission rate factors, which are established from the sulfur content and gross calorific value of the fuel being burned (see Docket A–97–35, Items II–A–11, II–I–1). Since the SO_2 emissions are directly proportional to the amount of sulfur in the fuel and in light of the limited variability in the sulfur content of natural gas and oil, the proposed SO_2 mass emission factors should be fairly representative of uncontrolled, actual emissions. Because of the relatively low sulfur content of natural gas or oil, it is doubtful that any of such units have SO_2 controls. The proposed factors fall within the typical range of sulfur content and gross calorific value for each fuel, although somewhat on the conservative side for sulfur content of diesel fuel and natural gas other than pipeline natural gas.

For determining NO_X mass emissions and emission rate, EPA proposes using the fuel- and unit-type-specific NO_X emission rate factors based on 90th percentile emission rate data reported under part 75 generally for uncontrolled units (see Docket A–97–35, Item II–A–9). While attempting to develop an accounting approach for NO_X emissions from low mass emission units, EPA encountered several issues. The first issue involves the use of AP–42 factors. During the finalization of the core part 75 monitoring rule, EPA considered allowing peaking units with negligible emissions both individually and collectively to estimate NO_X emissions using AP–42 emission rate factors. EPA rejected this approach in the January 11, 1993 final rule preamble at 58 FR 3644–45 because the AP–42 emission rate factors are derived from industry-wide average estimates of emissions for different fuel and boiler types and are not based on actual historical operating experience of the units to which the estimates would be applied. Applying AP–42 factors could result in underestimation of NO_X emissions because actual NO_X emissions can vary significantly from unit to unit. The formation of NO_X from the combustion of fossil fuels is dependent on the amount of nitrogen in the fuel being combusted and on the mix of nitrogen and oxygen in combustion air. Further, the NO_X formation process depends on unit-specific factors of combustion gas temperature and stoichiometry of fuel and air local to the flame. Consequently, there can be significant variations in the level of NO_X emissions from unit to unit due to variations in combustion conditions. Therefore, EPA is not proposing the use of AP–42 factors to estimate NO_X emissions from low mass emissions units. Instead, now that three years of actual historical operating data collected under part 75 are available, it was possible to develop the default NO_X emission rate factors being proposed today. Although the default NO_X emission rate factors in today's proposal are generic factors, they should not underestimate NO_X emissions because they are based on the 90th percentile of actual annual average emission rates reported generally from uncontrolled units under part 75.

The Agency also considered using site-specific NO_X emission rate factors based on historical emission data or emissions testing data for the unit. For example, a facility might use the maximum value ever recorded by the CEM for the unit, or it might use the highest NO_X emission rate value calculated from the unit's most recent Appendix E NO_X test, or it might use site-specific values similar to those discussed in the guidance manual for implementing the NO_X budget program in the OTR (see Docket A–97–35, Item II–I–7). The application of site-specific NO_X emission factors for low mass emission units raises several issues. First, for units with pollution controls where the emission factor is based on controlled emissions, the site-specific emission factor could underestimate actual emissions if the controls are not operating properly. EPA considered only allowing site-specific NO_X emission factors with units that do not utilize NO_X emission controls; however, EPA realizes that many units employ at least some form of NO_X emission controls (e.g., water or steam injection). EPA also considered allowing a source with controls to use a site-specific emission factor only if it could demonstrate that the pollution controls are operating properly. However, this would involve extensive, additional recordkeeping and tracking to verify the proper operation of pollution controls and ensure that emissions are not underestimated; this would run contrary to the general approach under the exception of reducing monitoring and reporting requirements. A second issue involves verifying that the site-specific NO_X emission factor is still representative over time or after unit modifications. This would require future NO_X emission rate testing. Therefore, for purposes of creating a methodology that is simple to implement and in order to reduce future testing requirements for facilities with low mass emitting units, the Agency proposes instead using NO_X emission rate factors based on fuel and unit type and reflecting uncontrolled emissions. EPA requests comments on this approach, whether other approaches should be used, and especially whether there are any additional boiler types not represented in today's proposed rule for which NO_X emission rates should be provided.

For determining CO_2 mass emissions, today's rule proposes to use CO_2 emission rate factors in tons/mmBtu. The CO_2 emission rate factors are derived based on ideal gas theory and standard Agency F_c factors for estimating the volume of CO_2 to be emitted when a certain heat input of a particular fuel is burned (see Docket A–97–35, Item II–A–11). This resembles the approach currently used in Equation G–4 of Appendix G for gas-fired units.

Therefore, the Agency believes that an appropriate method of estimating emissions for the purposes of qualifying for a reduced monitoring and reporting exception and for purposes of emissions accounting and compliance for units under the exception is to calculate emissions based on the actual number of operating hours and the actual fuel burned using maximum rated hourly heat input and fuel-based and, for NO_X unit-type-based, emission factors. The Agency requests comments on this approach and on whether an alternate approach should be used. While the Agency believes that the resulting emissions estimates will in most, if not all, cases be conservative and result in an overestimation of emissions, it would be possible, however unlikely, that the estimate could underestimate the actual emissions for some types of units. Therefore, for existing units with historical emissions data available, the proposal would require that in addition to meeting the applicability criteria using the emissions estimates calculated as described above, the unit would have to meet the cutoffs for initial qualification for the exception using the actual annual emissions monitored during the three years prior to applying to use the exception.

3. Cutoff Limit for Applicability

EPA began developing applicability criteria by first considering the level of projected aggregate emissions determined to be *de minimis* for purposes of developing the new unit exemption promulgated in the January 11, 1993 Acid Rain permitting rule (*see* 58 FR 3593–94 and 3645–46). Aggregate emissions projected for units under the exemption were approximately 138 cumulative tons of SO_2 and 1934 cumulative tons of NO_X emitted per year. The Agency then conducted a study of actual emissions data from 1996 quarterly reports under part 75 and evaluated potential tonnage cutoffs for SO_2 and NO_X. The Agency compared the cumulative mass emissions from groups of units emitting less than various specified amounts to the total emissions reported under the Acid Rain program during the year (see Docket A–97–35, Item II-A–10). For example, the study shows what proportion of total SO_2 was emitted by units with both actual and potential [1] emissions of 25 tons or less per year, 50 tons or less per year, 60 tons or less per year, and 75 tons or less per year. From these analyses, EPA also estimated how many units might be eligible for reduced requirements for determining emissions and how much of an impact the new emissions accounting option would have on nationwide emissions accounting.

EPA is proposing cutoff values of 25 tons per year of SO_2 and 25 tons per year of NO_X. In order to qualify as a low mass emissions unit, a unit would have to demonstrate that both actual historical emissions and potential emissions (calculated with maximum hourly heat input, emission factors and either, for existing units, actual historical number of operating hours or, for new units, projections of future annual operating hours) do not exceed 25 tons each for SO_2 and NO_X on an annual basis. Based upon its analyses (see Docket A–97–35, Item II-A–10), EPA estimates that this tonnage cutoff level would mean that the group of units subject to the proposed reduced requirements, even after Acid Rain Program emission reductions are considered, would have total annual emissions of about 16 tons of SO_2 and 90 tons of NO_X (less than a thousandth of a percent of total annual SO_2 emissions and about 0.002 percent of total annual NO_X emissions for all affected units). Both amounts, 16 tons of SO_2 and 90 tons of NO_X, are less than the total number of tons of those pollutants determined to be *de minimis* for purposes of the new unit exemption. Today's proposal to treat low mass emission units as *de minimis* is consistent with the *de minimis* conclusions reached for new units.

While the reduced requirements are somewhat less accurate than the methodologies under the existing regulations, the reduced requirements are intended to yield emissions data that are conservative and that, to the extent they are inaccurate, are likely to overstate emissions. Moreover, EPA believes that the level of inaccuracy (i.e., overstatement of emissions) would similarly be extremely low (i.e., less than a thousandth of a percent). Both the total emissions subject to the reduced requirements and the potential amount of overstatement of emissions are *de minimis*. Moreover, any overstatement of regulated emissions would have the effect of tightening emission limits (e.g., by requiring surrender of more allowances for SO_2 than otherwise). Any overstatement of other emissions would be too small to affect adversely the air quality related activities (e.g., air quality modeling) for which the emissions data would be used.

EPA would, however, be concerned about extending today's proposed reductions in monitoring, quality assurance, and reporting requirements to units that exceed the 25-ton cutoffs for actual or potential emissions. Section 412 of the CAA requires all affected units to monitor SO_2, volumetric flow, NO_X, and opacity using continuous emission monitoring systems or an alternative monitoring system approved by the Administrator as having the same precision, reliability, accessibility, and timeliness. In addition, section 412 of the Act requires that emissions data be quality-assured. Section 821 of the Clean Air Act Amendments of 1990 provides that, through regulations issued by the Administrator, all affected units must be required to monitor CO_2 emissions in the same manner and to the same extent as SO_2 and NO_X are monitored under section 412. Part 75 of EPA's rules requires monitoring of SO_2, NO_X, and CO_2 and allows certain exceptions to the statutory requirement for CEMS or CEMS-equivalent alternative monitoring: in Appendix D because, *inter alia,* the information gathered using the Appendix D methods is as precise, reliable, accessible, and useful as that from CEMS, and compares acceptably with regard to timeliness; and in Appendix E because the emissions from all units eligible to use Appendix E are negligible and such units do not have emission limitations for NO_X under the Acid Rain Program (see 58 FR 3641–45). The proposed reduced monitoring and reporting requirements for low mass emissions units would not yield information equivalent to that from CEMS. EPA must balance the benefits of reduced monitoring, quality assurance, and reporting requirements for units against the intent of the statute that monitoring with CEMS or their equivalent be required so as to obtain reliable, precise, timely, and readily accessible information on emissions. EPA solicits comment on whether 25 tons is the appropriate cutoff level for applicability of the low mass emission excepted methodology.

In particular, EPA is concerned that extending the proposed reduction in requirements to units with more than this *de minimis* level of emissions could have a negative impact on the environment. Emissions data from the Acid Rain Program are being used for a variety of efforts, including emissions modeling and establishing baseline emissions information (prior to any emission reductions) for new air pollution control programs. Using less accurate methods to monitor more than a *de minimis* amount of emissions could potentially undermine efforts to establish baseline emissions and to assess what emission reductions have already taken place and how much further emissions must be reduced in order to meet air quality standards.

Furthermore, with regard to coal-fired units, such units account for the largest proportion of all emissions, tend to be operated more frequently, and generally have much higher emission rates in lb/mmBtu for SO_2, NO_X and CO_2, and the majority of the units have emission limitations and emission reduction

[1] The terms ''potential emissions'' used in this section of the preamble have a different meaning than the terms ''potential to emit'' used elsewhere by the Agency.

requirements for SO_2 and NO_X. In addition, the sulfur content in coal and gaseous fuels other than natural gas is much more variable than for natural gas and oil, and the emission factors for coal or gaseous fuels other than natural gas, particularly an SO_2 emission factor, are therefore less reliable and much more likely to understate, rather than overstate, emissions. Based on these considerations, the proposed rule would restrict the use of the reduced requirements to gas-fired units and oil-fired units that burn natural gas and/or fuel oil.

In order to qualify for the proposed low mass emissions excepted methodology, the proposed applicability criteria would require a unit to meet annual tonnage cutoffs of 25 tons each for SO_2 and NO_X. EPA considered whether the excepted methodology should be available on a pollutant specific level so that, for example, a unit which falls below the tonnage cutoff for SO_2 but not for NO_X could use the proposed excepted methodology under § 75.19 to measure SO_2 emissions but use a NO_X CEM or the excepted methodology under Appendix E, where applicable, to measure NO_X emissions. EPA believes this approach would not be appropriate because some of the same monitoring equipment and reporting software is necessary for measuring and reporting both of the pollutants. One of the prime benefits of the low mass emissions excepted methodology would be the simplified reporting which would require less time and a less sophisticated Data Acquisition and Handling System. In particular, the need for a DAHS that could calculate substitute data using the missing data algorithms would be removed because there are no missing data algorithms for the low mass emissions excepted methodology. If the excepted methodology is only applied to one of the pollutants, much of the benefit would be negated because the DAHS would still need to be capable of calculating substitute data for the measured pollutant and close to the full quarterly report would still be required. Another prime benefit of the proposed low mass emissions excepted methodology would be the removal of monitoring and quality assurance requirements. However, EPA believes that almost all units that would qualify for a 25-ton cutoff for only one pollutant would meet the cutoff for SO_2, not NO_X, and would already be using Appendices D and E. A unit using a fuel flowmeter to determine SO_2 mass emissions under Appendix D likely uses the same fuel flowmeter to determine CO_2 emissions and heat input. Additionally, the same fuel flowmeter is used to determine NO_X emissions under Appendix E. Even if the unit were allowed to use the proposed low mass emissions excepted methodology for SO_2 in lieu of Appendix D, the unit would still have to install, certify, operate, maintain, quality assure, and report from a fuel flowmeter to determine NO_X emission rate and heat input. Accurate heat input is important since heat input is used to calculate NO_X mass emissions. In short, the cost of operation, maintenance, and quality assurance of the fuel flowmeter would not be removed simply by removing the requirement to monitor SO_2. Even if a unit that qualified under the low mass emissions excepted methodology for SO_2 but not for NO_X was currently monitoring with Appendix D, for SO_2 and heat input, and using a NO_X CEM, for NO_X emission rate, using the excepted methodology for SO_2 but not for NO_X would have little benefit since the installation, certification, and quality assurance testing of the fuel flowmeter would still be required to determine heat input. Therefore, today's proposed low mass emissions excepted methodology would be provided as an option only if the unit has low mass emissions of both SO_2 and NO_X. EPA solicits comment on this approach and on whether any benefit of allowing the excepted methodology for one pollutant only would outweigh the added complexity in the excepted methodology.

EPA also considered whether a tonnage cutoff for CO_2 emissions was appropriate as part of the proposed applicability criteria for low mass emissions units. However, the proposed excepted methodology under § 75.19 would require the use of a standard emission factor (in lb of NO_X/mmBtu) for NO_X to determine eligibility for the exception. This would effectively establish an upper limit on the annual heat input for a given fuel and boiler type at the level that would allow the unit to meet the tonnage cutoff applicability requirements. Because CO_2 emissions are directly proportional to heat input, there would be a built-in annual CO_2 emissions cutoff inherent in the methodology.

4. Continuing Applicability Criteria

In drafting today's proposal, EPA also considered how to ensure that after individual units initially qualified to use the reduced monitoring exception, they could continue to use the exception only if they continued to have *de minimis* emissions. Many of the units that would qualify as low mass emissions units under the proposal have low emissions either because they use pipeline natural gas and/or because they operate infrequently. In both of these situations, it is conceivable that a unit's emissions could become significant if the unit's fuel or hours of operation were to change. Most gas-fired units are capable of burning oil, but generally do so only when pipeline natural gas is not available. However, if the prices of gas and oil were to change such that oil became far more economical than gas, some gas-fired units might switch to burning high sulfur oil. Similarly, increases in demand for electricity could cause some peaking units to operate more frequently, thereby generating more emissions. Therefore, EPA is proposing that in order to ensure that emissions from units using the reduced requirements would remain *de minimis*, units would have to continue to meet the applicability criteria in order to qualify as low mass emissions units. Because of the conservative heat input and in some cases, conservative emission factors, the Agency believes that meeting the applicability criteria of less than 25 tons of both SO_2 and NO_X when calculating the emissions using the low mass emissions excepted methodology, will ensure that the actual emissions of the low mass emission units will be below those levels. Therefore, once the methodology is implemented, the on-going applicability would only require that the limits be met with the calculated mass emissions, i.e., the facilities would be required to continue to meet the 25-ton cutoffs on an annual basis, as determined using the emission calculation procedures in proposed § 75.19.

It would, therefore, be necessary for low mass emissions units to report NO_X mass emissions, in addition to the required SO_2 mass emissions and NO_X emission rate, in order to determine continuing applicability. A continuing applicability provision of this nature would prevent a unit from continuing to use the reduced requirements when its emissions were no longer negligible. If a unit initially met the applicability criteria but failed to meet one or both of the annual 25-ton cutoffs in a future year, the unit would become disqualified from using the exception. Sufficient time would be necessary to purchase, install, and certify CEMS or the equipment necessary for monitoring under Appendices D and/or E. Therefore, a unit would not be disqualified until two calendar quarters after the quarter in which the 25-ton cutoff is exceeded and would not be required to certify and report from monitoring systems until then. If that unit changes, or is projected to change, its fuel or amount of operation in the future so that it would again meet the 25-ton SO_2 and NO_X cutoffs, the unit could again qualify as a low mass emissions unit. However, if the unit initially qualified based on projected operating hours and fuel usage and then was disqualified the unit could not use projected data to qualify again. The unit would need to monitor using CEMS, an approved alternative monitoring system, or an optional protocol under Appendices D and/or E, where applicable, for at least an additional three years in order to accumulate three years of actual data.

5. Reduced Monitoring and Quality Assurance Requirements

As discussed above, today's proposed rule would allow facilities to use a maximum rated hourly heat input value and an emission rate factor to determine the mass emissions from a low-emitting unit for each hour of actual operation. This approach would involve no actual emissions monitoring and no quality assurance activities. Instead, the facility would only need to keep track of whether the unit combusted any fuel for a particular hour and what type of fuel was combusted. In this way, the proposed revisions would significantly reduce the burden on affected facilities, while still ensuring that emissions are not underreported.

6. Reduced Reporting Requirements

Some utilities have mentioned that they find it troublesome to spend as much time or more reviewing quarterly report submissions for small, infrequently operating gas-fired units as they spend reviewing quarterly report submissions for large coal-fired units (see Docket A–97–35, Items II–D–75, II–E–25). EPA agrees that facility environmental personnel should be able to spend a greater percentage of their time focusing on units with higher emissions than on low mass emissions units, which, as discussed above, account for such a small portion of total emissions. Thus, today's proposed rule would simplify the reporting requirements for low-emitting units so that facilities could spend less of their environmental department resources on units with negligible emissions. For units that rely on the procedures in proposed § 75.19(c), the owner or operator would have no requirements related to records or reports of certification testing and would be exempt from all of the specific recordkeeping requirements in §§ 75.54(b) through (e) or 75.57(b) through (e) relating to operating parameter and emissions records. Instead, the rule would require only that an initial certification application, containing data supporting the applicability demonstration, and a monitoring plan be submitted and that limited hourly, quarterly, and year-to-date cumulative data be reported on a quarterly basis. The hourly record would only be reported for hours of unit operation, and an hour in which the unit combusted fuel for any portion of the hour would be considered a full hour, for simplicity.

One utility has suggested that it would be less burdensome if it could simply report its quarterly cumulative emissions, without reporting any supporting hourly data; other utility representatives have indicated that it would be no more burdensome to report an hourly default emission value if the utility were already reporting hourly operating information (see Docket A–97–35, Item II–E–25). For purposes of modeling air quality, the Agency considers hourly operating information far more valuable (e.g., for modeling discrete periods of ozone exceedance) than just a quarterly emission value with no time or date mentioned. Furthermore, because facilities already keep track of the operation of their units for business purposes, keeping track of and reporting hourly operating information should not be a substantial burden. According to industry representatives, however, allowing facilities to record and report default emission values instead of hourly measured values would significantly speed up their review of quarterly reports prior to submission to the Agency (see Docket A–97–35, Item II–E–25). Thus, requiring facilities to report hourly operational data and the default emissions data for the fuel burned that hour, but not hourly measured emissions or heat input in additional record types, would preserve the Agency's ability to model air quality while imposing far less burden upon facilities than the current part 75 requirements. Furthermore, because hourly default values would be employed, the need for missing data procedures would be eliminated and the Data Acquisition and Handling System (DAHS) could be greatly simplified. In fact, the reporting requirements for a low mass emissions unit could most likely be fulfilled with the use of a commercially available spreadsheet software package. EPA has incorporated this approach into today's proposed rule.

D. Quality Assurance Requirements for Moisture Monitoring Systems

Background

Section 75.11(b) of the original 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 (see §§ 75.13(c), 75.16(e), and Equations F–14b, F–16, F–17 and F–18 in Appendix F) or when determining NO_X emission rate in lb/mmBtu (see section 3.2 in Appendix F, and Equations 19–3 through 19–5, 19–8, and 19–9 in Method 19 of Appendix A to part 60).

As presently codified, part 75 does not specify any quality assurance requirements for moisture measurement devices. Implementation has shown this to be an unfortunate omission in the rule, since 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. The Agency does not know the extent of inaccuracy that currently exists in the measurement of moisture by affected units but believes it is important to require certification and quality assurance of moisture monitors—just as is required for other CEMS used under part 75—because the success of the SO_2 trading system depends on accurate monitoring.

Discussion of Proposed Changes

Today's proposal would incorporate into part 75 quality assurance requirements for moisture monitoring systems. Section 75.11(b) would be revised to require the owner or operator to install, maintain, operate, and *quality assure* a moisture monitoring system. Proposed § 75.11(b) also specifies that a moisture monitoring system may either consist of: (1) a continuous moisture sensor; (2) an oxygen 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 DAHS component capable of determining moisture from a lookup table, i.e., a psychrometric chart (this third option would apply only to saturated gas streams following wet scrubbers). Corresponding changes would be made to §§ 75.12, 75.13(c) and 75.16(e) to require that a quality assured moisture monitoring system be used whenever moisture corrections are needed to accurately account for NO_X emissions, CO_2 emissions, or heat input.

Requirements for the initial certification of moisture monitoring systems are proposed in three new sections, §§ 75.20(c)(5), (c)(6), and (c)(7). To make room for the new sections, existing § 75.20(c)(3) would be deleted; existing §§ 75.20(c)(4) and (c)(5) would be redesignated as §§ 75.20(c)(3) and (c)(4); and existing §§ 75.20(c)(6), (c)(7), and (c)(8) would be redesignated, respectively, as §§ 75.20(c)(8), (c)(9), and (c)(10). The certification requirements for continuous moisture sensors are found in proposed § 75.20(c)(6) and include a 7-day calibration error test and a relative accuracy test audit (RATA). For moisture monitoring systems consisting of one or more wet- and dry-basis oxygen analyzers, the proposed certification requirements are found in § 75.20(c)(5) and include 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. Corresponding revisions to § 75.22(a)(4) are proposed, specifying that EPA Method 4 (either the standard procedure or the midget impinger procedure) would be used as the reference method for the moisture RATAs. For saturated gas streams, if a lookup table is used to determine the hourly stack gas moisture content, the certification requirement in proposed § 75.20(c)(7) would consist of a DAHS verification. At a minimum, the DAHS verification would have to demonstrate, at three temperatures covering the normal range of stack temperatures, that the software extracts the proper moisture value from the lookup table and applies it correctly to the emission calculations. In today's proposal, a new § 75.4(i) would also be added, requiring owners or operators to complete all of the applicable moisture monitoring system certification tests specified in proposed §§ 75.20(c)(5), (c)(6), and (c)(7) no later than January 1, 2000.

Proposed performance specifications for moisture monitoring systems are found in sections 3.1, 3.2, 3.3, and 3.5 of Appendix A to part 75. These specifications would apply to continuous moisture sensors and to wet- and dry-basis oxygen analyzers. The proposed calibration error specification in section 3.1 for continuous moisture sensors is 3.0 percent of span. A new section, 2.1.5, would be added to Appendix A, defining the span of a moisture sensor as equal to the full-scale range of the instrument and requiring that the range be consistent with section 2.1 of Appendix A. 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 in sections 2.1.3, 3.1, 3.2, and 3.5 of Appendix A would be the same as the current specifications for O_2 monitors. The proposed relative accuracy (RA) specification for moisture monitoring systems is found in a new section, 3.3.6, in Appendix A and would be equal to 10.0 percent. An alternative RA specification would also be provided in section 3.3.6, i.e., the relative accuracy would also be acceptable if the difference between the mean difference of the reference method measurements and the moisture monitoring system measurements is within ± 1.0 percent H_2O. A relative accuracy specification of 10.0 percent is being proposed in order to maintain consistency with the relative accuracy requirements for the other program monitors (SO_2, NO_X, flow rate, and CO_2). The Agency notes that moisture RATAs have not previously been required by any other EPA continuous monitoring regulation, and therefore there is no relative accuracy database upon which to draw. However, moisture data are sometimes collected using EPA Method 4 during each run of a part 75 gas monitor RATA to convert the gas reference method readings from a dry basis to a wet basis. Therefore, some part 75 sources that currently account for moisture using wet- and dry-basis oxygen analyzers or a moisture sensor should be able to construct moisture RATAs from previous test data by comparing the Method 4 moisture data from the gas monitor RATAs against the readings recorded by the moisture sensor or O_2 analyzers at the time of the gas RATAs. EPA encourages those facilities that currently make moisture corrections in their emission equations to perform this type of data analysis, if possible, and to provide comment on the appropriateness of the proposed moisture relative accuracy specification.

On-going QA requirements for moisture monitoring systems are also proposed in sections 2.1.1, 2.1.4, 2.2.1, 2.3.1.1, and 2.3.1.2 of Appendix B to part 75. Proposed section 2.1.1 of Appendix B would require daily calibrations of moisture monitoring systems. Continuous moisture sensors would be calibrated in accordance with the manufacturers' recommended procedures. Proposed section 2.1.4 would give control limits for the daily calibrations (i.e., ± 1.0 percent O_2 for oxygen analyzers and ± 6.0 percent of span for continuous moisture sensors). Proposed section 2.2.1 would require quarterly linearity checks of wet- and dry-basis oxygen analyzer(s). Proposed section 2.3.1.1 would require semiannual RATAs of moisture monitoring systems, and proposed section 2.3.1.2 would specify that if a moisture monitoring system achieves a relative accuracy of ≤ 7.5 percent or if the mean difference between the CEMS and reference method values is within ± 0.7 percent H_2O, the system qualifies for an annual, rather than semiannual RATA frequency.

Missing data procedures for moisture are included in today's proposal in a new section, § 75.37. The proposed missing moisture data procedures are as follows:

(1) Begin by using the following ''initial'' missing data procedures as of the date and time of provisional certification of the moisture monitoring system or as of January 1, 2000 (whichever is earlier). Substitute 0.0 percent moisture for each hour of missing data if no prior quality assured data exist, and for the first 720 hours of quality assured monitor operating data, substitute, for each hour of each missing data period, the average of the ''hour before'' and ''hour after'' moisture values.

(2) After 720 hours of quality assured data have been obtained, provided that the moisture data availability is ≥ 90.0 percent, substitute the average of the ''hour before'' and ''hour after'' values for each hour of the missing data period.

(3) When the percent data availability for moisture is below 90.0 percent, substitute 0.0 percent moisture for each hour of the missing data period.

These proposed missing data procedures are considerably simpler than the corresponding procedures for SO_2, NO_X, CO_2, and flow rate, in that they do not include the concepts of lookback periods, 90th, or 95th percentile values. However, the procedures are also somewhat less representative than the missing data procedures for SO_2, NO_X, CO_2, and flow rate, because the most conservative possible value (0.0 percent moisture) is substituted when the moisture monitor data availability drops below 90.0 percent. The Agency solicits comment on whether the simpler (but less accurate) missing data procedures or the more complex (but more representative) procedures are more appropriate.

Finally, §§ 75.57(c) and 75.59(a) (revised versions of §§ 75.54(c) and 75.56(a)) would be added in today's proposal to require that records be kept of the following: (1) Component-system identification code for the moisture monitoring system; (2) hourly average moisture readings (including, if applicable, hourly averages from each wet- and dry-basis O_2 analyzer); (3) percent data availability for the moisture monitoring system; (4) daily and 7-day calibrations of moisture monitoring systems; (5) linearity tests of each wet and dry oxygen analyzer used to determine moisture; and (6) relative accuracy tests of moisture monitoring systems.

In summary, EPA is proposing quality assurance (QA) procedures for moisture monitoring systems because the Agency believes that continuous, quality assured, direct measurement of the stack gas moisture content or continuous measurement of surrogate parameters, such as wet- and dry-basis oxygen concentrations, is the best way to ensure the accuracy of the reported emission data when moisture corrections must be applied. However, the Agency is willing to consider and solicits comment on simpler alternative methods of accounting for the stack gas moisture content, such as using a conservative default moisture value. Any proposed alternative methodology submitted to the Agency for consideration would have to provide a comparable level of accuracy and would have to ensure that emissions and heat input are not under-reported.

E. Certification/Recertification Procedural Changes

Background

Currently, § 75.20 lays out the process for certifying monitoring systems. Section 75.20(a) specifies the requirements for initial certification, including the contents of a certification application, when the application must be submitted and the process for reviewing and acting on an application. Sections 75.20(a)(3) and (4) of the existing rule establish a certification application review period of 120 days (after receipt of a complete application) for EPA to review an application and issue an approval or disapproval. For a continuous emission monitor (CEM), initial certification includes the following tests: relative accuracy, bias, linearity (pollutant monitors only), 7-day calibration error, cycle response time (pollutant monitors only), missing data, and formula verification. All of these tests must be passed for a CEM to be certified and produce valid quality assured data. Once a CEMS is certified, § 75.20(b) specifies that if something changes that significantly affects the ability of the CEM to accurately measure concentration or volumetric flow, the affected monitoring system(s) must be recertified. Recertification includes one or more of the initial certification tests. All required recertification tests must be passed, and a recertification application must be submitted in order for a CEM to be recertified. Section 75.20(b)(5) of the existing rule establishes a 60 day review period for recertification applications. Separate but similar certification and recertification test requirements apply for a monitoring system other than a CEM, i.e., an excepted monitoring system under Appendix D or E, an alternative monitoring system under subpart E, or a system under proposed Appendix I.

Submittal requirements for certification and recertification applications are included in §§ 75.60 and 75.63 of the current part 75. Generally, these provisions require submittal of certification test results in electronic formats, with some information required to be submitted in hardcopy format. Certification or recertification test results also must be submitted electronically in quarterly reports under § 75.64. Finally, § 75.61 requires the designated representative to provide advance notice to the applicable state or local agency and EPA Regional Office of certification and recertification testing.

In many respects, monitoring plan requirements are tied to the certification/recertification process because a modification to the monitoring system that requires a recertification application also usually requires a monitoring plan update. In addition, because it contains the information about what type of equipment is located where, the monitoring plan is an essential tool in the review of a certification or recertification application. Section 75.53 specifies the content of monitoring plans and when changes to the plan are required. Section 75.62(a) specifies the submission requirements for monitoring plans.

Based on EPA's initial experience with part 75 implementation and the numerous questions and problems encountered in the review of certification and recertification applications and monitoring plans, the Agency believes that the certification and recertification provisions and the related sections of the rule are possibly neither sufficiently detailed nor clear. Therefore, in today's rulemaking, EPA is proposing to revise those provisions and sections in order to improve the certification/recertification process. The issues addressed in today's proposed rule include the following: (1) whether a particular provision applies to initial certification, recertification, or both; (2) the scope of events that require submittal of a recertification application; (3) the review period lengths for initial certification and recertification applications; (4) the criteria governing disapproval of an incomplete certification or recertification application; (5) the format (electronic or hardcopy) in which test notifications, certification and recertification applications, and monitoring plans are to be submitted; (6) which EPA Regional Offices and state and local agency offices must receive test notifications, certification and recertification applications, and monitoring plans, and whether the submittal and notice requirements can be waived; and (7) when a monitoring plan needs to be revised. The proposed revisions on these topics and the rationale for the changes are discussed below.

The Agency notes that today's package of proposed revisions to part 75 includes other substantive revisions to the certification and recertification provisions in part 75. These are discussed elsewhere in this preamble. The provisions of most significance are related to certain proposed QA/QC revisions, back-up monitoring systems, CEM data validation issues, and the new Appendix I procedures. See sections III.D, O, R and T of this preamble for further discussion.

Discussion of Proposed Changes

The proposed revisions discussed in this section affect § 75.20 generally, as well as specific aspects of §§ 75.20(a)(4), (b)(1), (b)(5), and (g)(6); 75.21(e)(1); 75.53(b); new § 75.53(e) and (f); 75.60(b); 75.61(a); 75.62(a); 75.63(a) and (b); 75.64(a), (b) and (d) and the addition of § 75.59 as a revised version of § 75.56. Proposed revisions to § 75.20 would clarify which provisions apply to initial certification, recertification, or both. Proposed revisions to § 75.20(b)(1) and (g)(6) would provide a narrow definition of recertification events, thereby significantly reducing the number of monitoring system changes, configuration changes or changes in the manner of operation that would require submission of a recertification application. Proposed revisions to § 75.20(b)(5) would make the lengths of the review periods the same for initial certification and recertification applications. Proposed revisions to § 75.20(a)(4) would clarify what constitutes a complete certification or recertification application and also would more clearly define EPA's authority to disapprove an incomplete application.

Proposed revisions to § 75.53(b) would expand the universe of monitoring system changes that require monitoring plan revisions to include any change that would make the information in the current plan inaccurate (currently, only changes that require recertification require monitoring plan changes). Sections 75.53(e) and (f), which are revised versions of existing § 75.53(c) and (d), would clarify which elements of a monitoring plan must be submitted in electronic format and which elements must be submitted in hardcopy format. Section 75.53(e) would revise existing § 75.53(c) so that after January 1, 2000 an owner or operator would have to report the unit stack height in the monitoring plan. Section 75.59 (a revised version of § 75.56) would specify the minimum required content (as of January 1, 2000) for the hardcopy portion of a certification or recertification application. Section 75.60(b) would more clearly define the general requirements for submittal of reports and petitions. Section 75.61(a) would allow for certification and recertification test notices to be sent in various alternative media and would allow for EPA or a State or local agency to waive test notices in some circumstances. Section 75.62(a) would be revised to clarify when monitoring plans are to be submitted and to whom elements of the monitoring plan must be submitted. Similarly, § 75.63(a) would be revised to detail which elements of a certification or recertification application are to be submitted electronically, which elements are to be submitted in hard copy, and to whom the various elements would be submitted. Section 75.63(b) would clarify when and how failed tests are to be reported in a certification or recertification application. Finally, § 75.64(a) would specify that the hardcopy monitoring plan is not to be submitted with a quarterly report. The rationale for these changes is discussed below.

Rationale

1. Initial Certification Versus Recertification

Several provisions in the current rule refer either to certifications or to certification applications; however, it is not always clear whether these provisions apply solely to initial certifications or whether they also apply to recertifications. Therefore, today's proposed revisions would make a number of minor text edits throughout § 75.20 for clarification. There are, however, some events that do not fit neatly under the definition of initial certification or recertification (e.g., construction of a new stack with a new CEM at an existing unit when a scrubber is installed). This element of subjectivity in classifying an event as a certification or recertification makes it desirable for the certification and recertification processes to be as similar as possible. Having one general process with one set of rules rather than having two separate processes also makes program implementation easier. Currently, the main differences between initial certifications and recertifications are the types of tests required and the lengths of the application review periods. Today's proposed rule revisions would attempt to minimize these differences to the extent possible in order to bring greater uniformity and consistency to the certification and recertification process.

(a) *Scope of Recertification Events.* The proposed revisions would narrow the scope of the types of changes to a monitoring system that would be classified as ''recertification events'' and would require submittal of a recertification application. Sections 75.20(b)(1) and (g)(6) would define a recertification event as any change that requires the performance of an accuracy test of a monitoring system, i.e., either a relative accuracy test audit (RATA) of a CEMS, an accuracy test of a fuel flowmeter, or a retest to develop the Appendix E NO_X correlation curve. For changes to a monitoring system or process that do not require a system accuracy test but require one or more of the other (lesser) quality assurance tests to be performed (e.g., linearity test or 7-day calibration error test), those other required tests would be classified as diagnostic tests rather than as recertification tests in § 75.20(b)(1) of the proposal. For instance, a source would be required to conduct a linearity check after replacing a capillary tube in a gas analyzer with a tube from a like model and manufacturer (see Docket A–97–35, Item II–I–9, Policy Manual, Question 13.13). However, because this change to the CEMS does not require a RATA, it would not be considered a recertification event. Therefore, no recertification application would be required, and the linearity test would be considered a diagnostic test. Note that even though diagnostic tests would not be classified as recertifications, the recertification data validation procedures in proposed § 75.20(b)(3) of today's rule would apply to these tests. EPA believes that the proposed narrowing of the definition of a recertification event will significantly reduce the number of required recertification applications and will make the submittal requirements for initial certifications and recertifications more consistent.

(b) *Recertification Review Period.* Consistent with the proposed narrowing of the definition of a recertification event, EPA also proposes to revise § 75.20(b)(5) by increasing the recertification application review period from 60 days to 120 days to make it the same as the review period for initial certifications. The advantage of making the two review periods consistent is that there would be no need to distinguish which requirements are applicable to which events. Some events combine aspects of initial certification and of recertification. For example, the certification of a new CEMS on a new stack at an existing unit when a scrubber is installed can be thought of as initial certification because it is an entirely new system in a new location; however, this event also involves aspects of recertification because it is an existing unit which has been reporting emissions from certified systems. Therefore, the Agency believes that making the review periods the same would reduce confusion and case-by-case determination of how long the review period should be for a given application. The Agency believes that it would be more effective to establish consistent procedural requirements for both initial certification and recertification events, rather than attempting to classify each event as an initial certification or recertification.

In making the review periods consistent, EPA considered reducing the length of the review period for initial certifications. EPA considered both the time it takes to complete a thorough technical review of an application and the time it takes to resolve issues raised during that technical review. The resolution of issues raised during a review can take a significant amount of time because it involves coordination between the source submitting the application, the applicable state and/or local air agency, the applicable EPA Regional Office, and the Acid Rain Division at EPA headquarters. Therefore, even though EPA would anticipate receiving fewer recertification applications under today's proposed revisions, EPA believes that a 120-day review period is necessary for recertifications (which, according to today's proposed definition of a recertification event, would involve the review of monitoring system accuracy tests) in order to coordinate resolution of issues raised during the technical review of an application.

EPA recognizes that there are concerns with increasing the recertification review period to longer than 60 days, as more hours of data could be invalidated if an application were disapproved. However, EPA believes that the criteria for approval of monitoring system certification tests are clear and that when an application is submitted, the owner/operator should know whether or not the performance specifications of part 75 have been met. In EPA's experience of four years of implementation, disapprovals are rarely issued; in fact, less than 2 percent of all monitoring system applications submitted between 1993 and September 1997 were disapproved (see Docket A–97–35, Item II–A–4). In most cases where applications have been disapproved, the owner or operator should have been aware of the deficiencies before the application was submitted. Additionally, EPA has found that a longer review period has allowed more time to resolve minor deficiencies which could have served as grounds for disapproval, but which, given sufficient time, were often resolved without issuing a notice of disapproval and without invalidating any hourly emissions data.

2. Disapproval of an Incomplete Application

Section 75.20(a)(4) of the existing rule requires EPA to issue a "notice of approval or disapproval of the certification application within 120 days of receipt of the complete certification application." This provision implies that an application must be complete in order to issue a disapproval. In attempting to implement this provision, EPA has encountered the problem of incomplete applications. The Agency has, in most of these instances, issued a notice of incompleteness to the source. However, affected sources have not always complied with the incomplete notices and have sometimes failed to submit the information requested to complete the application in a timely manner. Therefore, EPA proposes to clarify that EPA may disapprove an incomplete certification or recertification application if the submittal deadline is passed. Before a disapproval would be issued for an incomplete application, the designated representative would receive a notice of insufficiency and be given a reasonable period of time to complete the application. If the complete application was not received by this extended deadline, EPA could issue a notice of monitoring system disapproval. The Agency believes that this provision will result in faster resolution of incomplete certification or recertification applications, thereby eliminating extended periods of uncertainty about data validation status.

3. Submittal Requirements for Certification and Recertification Applications

The current rule requires the owner or operator to submit certification and recertification applications to the Administrator (i.e., the Acid Rain Division of EPA) and to the appropriate EPA Regional Office and state or local air agency. Hardcopy test results must be submitted, as well as an updated monitoring plan and electronic test results. The electronic test results must also be submitted to the Administrator as part of the next quarterly report.

Sections 75.20(a)(4)(ii), 75.59, and 75.63 of today's proposal would revise and clarify the completeness, format, and submittal requirements for certification and recertification applications. For a certification or recertification application to be considered complete, the appropriate information specified in proposed § 75.63 would be sent to the Administrator, to the EPA Regional Office, and to the state and local air agency. Under proposed § 75.63, the Administrator would receive only a hardcopy application form and would not receive any hardcopy test results, unless specifically requested. The Administrator would, however, receive certification and recertification test results electronically in the quarterly report. In most cases, the electronic test results would be submitted in the quarter in which the testing is completed. However, there may be occasional exceptions to this, for initial certification testing and for recertification testing, when a series of tests spans two consecutive calendar quarters.

The local and State agencies, as well as the EPA Regional Office would receive a hardcopy application form, electronic test results, and hardcopy test results. For recertification tests, today's proposal would allow the EPA Regional Office or the state or local air agency to waive the requirement for a hardcopy recertification test report for their respective offices. The EPA Regional Office or the state or local agency could also reinstate that requirement at a later date. EPA Regional Offices and state and local agencies have historically received hardcopy certification and recertification reports with varying contents and formats. Section 75.59(a)(10) would specify the minimum content for hardcopy certification and recertification reports for gas and stack flow CEMS. Section 75.63(a)(2)(iii) would limit the amount of reporting for "non-recertification events" that require diagnostic tests. For a diagnostic test, the only reporting requirement would be to submit the applicable electronic test results in the next quarterly report. For DAHS verifications, no reporting would be required; instead, records of the tests would be maintained on-site in a manner suitable for inspection.

This series of revisions is intended both to clarify the elements of a complete application, and to clarify how and to whom the essential information should be submitted. By not requiring hardcopy test reports to be sent to the Administrator and by allowing the EPA Regional Office or state or local agencies to waive hardcopy recertification test reports, the Agency believes that unnecessary hardcopy reporting to offices that do not intend to review the reports will be eliminated.

Finally, § 75.63(b) would clarify that for failed certification or recertification tests, only tests that affect data validation would need to be reported. For example, if the ordinary rules of data validation, rather than the retrospective validation procedures, were applied and a test failure occurred during the initial certification testing for a new unit, only the passed test would be reported if the test was subsequently repeated and passed. However, if the conditional data validation procedures set forth in § 75.20(b)(3) of today's proposal had been utilized during that same initial certification, the failed test would have to be reported because it would affect the data validation of hourly emissions.

4. Decertification Applicability

The proposed revisions to § 75.21(e)(1) would clarify that excepted monitoring systems under Appendix D, E, or I or an alternative monitoring system under subpart E may be decertified in accordance with § 75.21(e)(1). The proposed revisions would also clarify that decertification would apply to both an initial certification and a recertification. EPA believes that logic and consistency dictate the need for these changes.

5. Recertification Test Notice

Section 75.61(a) would be revised to reduce the burdens associated with submitting notices of recertification tests. The proposed revisions would allow EPA or the state agency to waive notification requirements for recertification tests. Currently, a designated representative must notify EPA and the state agency prior to commencing certification or recertification testing so that EPA or a state representative has an opportunity to observe the testing. Allowing the recertification notification requirement to be waived and providing more media options for notifications will help conserve paper, reduce the reporting burden, and provide more flexibility to facilities when scheduling tests. In addition, the Agency solicits comment on whether § 75.61 should be revised to state that the requirement for written notification could be satisfied by mail, facsimile, or e-mail, subject to approval by the agency receiving the notification.

6. Monitoring Plans

In §§ 75.53(e) and (f), which are revised versions of § 75.53(c) and (d), and § 75.62, today's proposal clarifies completeness and formatting requirements for monitoring plans. In § 75.53(e), the existing provisions would be separated into two separate paragraphs (e)(1) and (e)(2) to clarify which parts of the monitoring plan must be submitted in electronic format and which elements must be submitted in hardcopy format. In addition, a number of minor changes would be made to clarify the actual required content of the plan. Similarly, in § 75.53(f), the same type of revisions would be made to clarify the electronic versus hardcopy elements of monitoring plans for specific situations (Appendix D, E, and I units, units claiming an opacity exemption, and units with add-on emission controls). These proposed revisions are generally consistent with existing implementation of the monitoring plan reporting requirements and primarily would serve to clarify possibly ambiguous elements of the current rule. The revisions reflected in § 75.53(e) would add a requirement to electronically report in the monitoring plan the unit stack height above ground level and the stack base elevation above sea level. EPA understands that these data are readily available to unit owners and operators. EPA collects stack heights for some units, e.g., for new or modified sources subject to 40 CFR § 51.166. However, stack height data is not currently collected for all of the units affected under title IV of the Act. Moreover, the stack height data that the Agency has is inconsistent, i.e., some of the data are for stack height above sea level, some are for above ground level, and some are undefined. Stack height data is necessary to improve the modeling of plume height and transport of sulfates and nitrates as part of acidic deposition and other atmospheric modeling. EPA conducts atmospheric modeling as part of the congressionally-mandated program of air pollution monitoring, analysis, modeling, and inventory research under section 103 of the Act. Such modeling is also used to analyze the impact of the Act on the public health, economy, and environment, pursuant to section 312 of the Act. (See also, e.g., *Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments* at 3–6 through 3–11 (EPA, 1995)). EPA is also proposing to collect the Energy Information Administration (EIA) flue identification numbers associated with each unit. While this data is already reported to EIA, it is difficult to correlate it with the unit and stack level data reported to EPA. By having sources specify for each unit and stack the corresponding flue identification number reported to EIA, it will be easier to correlate the emissions data reported to EPA to other data that is reported to EIA and is used for atmospheric modeling purposes, such as stack exit temperature and velocity.

Section 75.62 would be revised to clarify which parts of the monitoring plan must be submitted to the EPA Regional Office and state and local agencies, and when such submittals are required. The Administrator would receive an electronic monitoring plan at the following times: (1) no later than 45 days prior to the initial certification application; (2) at the time of a recertification application, if a change in the hardcopy monitoring plan information is associated with the recertification event; and (3) in each electronic quarterly report. The EPA Regional Office and state and local agency would receive the required hardcopy monitoring plan 45 days prior to an initial certification. Thereafter, hardcopy monitoring plan information (changed portions, only) would be submitted as follows: (1) with a recertification application, if a change in the hardcopy monitoring plan information is associated with the recertification event; and (2) within 30 days of any other event with which a hardcopy monitoring plan change is associated. Finally, today's proposed rule would require a complete monitoring plan to be kept on-site in a form suitable for inspection (this could include an electronic portion which could be printed out for inspection). These revisions are intended to clarify the monitoring plan format and submission requirements, but are generally consistent with existing practices.

Today's proposal would also clarify when revisions must be made to the monitoring plan. Currently, only changes that require recertification require monitoring plan revisions. The EPA recognizes, however, that many changes affecting the information in a monitoring plan would not require recertification. Therefore, § 75.53(b) would be revised to require that the owner or operator update a monitoring plan whenever information in the monitoring plan changes (e.g., a change to a serial number for a component of a monitoring system), and § 75.62 would require submission of the revised monitoring plan in the next quarterly report or, for hardcopy portions, within 30 days of the change. This revision would assure that the monitoring plan does not contain outdated, erroneous information.

Section 75.64(a) would clarify that no hardcopy monitoring plan is to be submitted with a quarterly report.

7. Submittal Requirements for Petitions and Other Correspondence

Section 75.60(b)(5) would clarify what hardcopy information is sent to the Administrator for petitions and other communications. These revisions would clarify the existing rule, but would not represent a significant change in the requirements for these types of submittals.

F. Substitute Data

1. Missing Data Procedures for CO_2 and Heat Input

Background

In the May 17, 1995 rule, two new sections, §§ 75.35 and 75.36, were added to part 75. These two new sections provided, respectively, missing data procedures for CO_2 and heat input, which were not provided in the original January 11, 1993 rule. Section 75.35 specifies that for CO_2, the initial missing data procedures of § 75.31 are to be followed for the first 720 quality assured monitor operating hours following initial certification. Thereafter, provided that the CO_2 data availability (as of the last hour of the previous quarter) is maintained above 90.0 percent and provided that the length of any CO_2 missing data period does not exceed 72 consecutive hours, a simple average of the ''hour before'' and ''hour after'' CO_2 concentrations is used to fill in missing data periods. However, if the monitor availability as of the last hour in the previous quarter is below 90.0 percent or if a CO_2 missing data period exceeds 72 consecutive hours in length (regardless of the percent monitor availability), then the fuel sampling procedures of Appendix G must be used to provide substitute CO_2 data.

Section 75.36 has a parallel structure to § 75.35. For units that determine unit heat input by using a flow monitor and a diluent (CO_2 or O_2) monitor, the initial missing data procedures of § 75.31 are to be followed for the first 720 quality assured monitor operating hours (for the diluent monitor) and for the first 2,160 quality assured monitor operating hours (for the flow monitor), following initial certification. Thereafter, the standard missing data procedures of § 75.33 are to be followed for the flow monitor. For the diluent monitor, the on-going missing data provisions of § 75.36 are nearly identical to those for CO_2 in § 75.35 (i.e., use an ''hour before hour after'' missing data algorithm, provided that the monitor availability is $\geq$ 90.0 percent and the missing data period length is $\leq$ 72 hours). However, when the diluent monitor availability is < 90.0 percent or when the diluent missing data period exceeds 72 hours, § 75.36 specifies that the owner or operator must use the procedures in section 5.5 of Appendix F to determine the hourly heat input.

Utility representatives have asked EPA to consider revising the missing data procedures for CO_2 and heat input (see, e.g., Docket A–97–35, Items II–D–20, II–D–30, II–E–13, and II–E–14). The utilities object to several elements of the current procedures. They suggest that the Appendix G procedures are burdensome and that the missing data procedures are considerably different from the standard missing data procedures for SO_2, NO_X, and flow rate, which are based solely on historical data and monitor availability and require no additional procedures such as fuel sampling.

Discussion of Proposed Changes

EPA has reconsidered the provisions of §§ 75.35 and 75.36 in light of the concerns raised by the regulated community, and is proposing revisions to the diluent gas missing data procedures for CO_2 and for heat input determinations. The Agency proposes that the same missing data routines prescribed in § 75.33(b) for SO_2 pollutant concentration monitors also be applied to the CO_2 and O_2 data streams that are used to determine CO_2 emissions and heat input. The diluent gas substitute data values would therefore be determined in a purely mathematical way, based on historical data and the percent monitor data availability; no fuel sampling procedures would be required.

Note that these proposed revisions would require the percent monitor data availability to be known on an hourly basis. This would require the percent availability for CO_2 and O_2 monitors to be updated hourly within the data acquisition system. EPA realizes that this would involve software modifications, and in cases where the unit heat input is determined using a flow monitor and an O_2 diluent monitor in accordance with Equation F–17 or F–18, some new recordkeeping provisions would also be required. The necessary recordkeeping provisions have been proposed in § 75.57(g). To allow time for software revisions to be made, the revised missing data procedures in §§ 75.35 and 75.36 would not take effect until January 1, 2000. The owner or operator could, however, opt to use the new procedures prior to January 1, 2000.

EPA believes that today's proposed revisions to the missing data procedures for CO_2 and heat input determinations would be relatively easy to implement because the missing data routines for SO_2 monitors are well-established and are familiar to both the regulated community and to software vendors. The Agency believes that the proposed revised missing data procedures would ensure that data availability remains high and would, over time, reduce the cost of compliance with the requirements of part 75.

2. Prohibition Against Low Monitor Data Availability

Background

Under the current rule, when a unit uses SO_2, flow rate, and NO_X monitoring systems to account for its emissions, for each clock hour in which a CEMS fails to provide quality assured data, a substitute data value must be reported to EPA in accordance with the standard missing data procedures of § 75.33. The method required for determining the appropriate substitute data values under § 75.33 depends on several factors, such as the overall monitor data availability and the length of the missing data period. For monitor data availabilities $\geq$ 90.0 percent, the substitute data value (which is reported for each clock hour of the missing data period) will normally be the arithmetic average of the readings from the hour before and the hour after the missing data period. At other times, it will be the 90th (or 95th) percentile value from a lookback period of 720 (for SO_2) or 2,160 (for NO_X and flow rate) quality assured monitor operating hours. When the data availability drops below 90.0 percent, the substitute data value for SO_2 will be the maximum concentration recorded in the last 720 quality assured monitor operating hours, and for flow rate and NO_X, the substitute data value will be the maximum flow rate or NO_X emission rate recorded in the last 2,160 quality assured monitor operating hours at the corresponding load range.

Based on four years of program implementation, EPA believes that the standard missing data procedures need to be strengthened. As presently written, the missing data algorithms lack a safeguard which will ensure that high monitor data availability continues to be maintained in future years. In the current version of § 75.33, no distinction is made between data availabilities of 89.0 percent, 50.0 percent or 10.0 percent. For all three of these data availability percentages, the substitute data value is the same (i.e., the maximum value in a lookback period of 720 or 2,160 quality-assured monitor operating hours). This has potentially serious consequences. For example, if the substitute data value from the lookback period is non-punitive or perhaps is even favorable to the facility (e.g., if a low-sulfur fuel was burned during the lookback period), there would be little incentive to repair a malfunctioning CEMS in a timely manner and emissions could possibly be under-reported for a long period of time. Currently, part 75 does not specifically address this ''gaming activity.''

Discussion of Proposed Changes

In order to maintain the credibility of the SO_2 allowance accounting system and to ensure that affected units continue to comply with their part 76 NO_X emission limits, monitor data availability must not be allowed to deteriorate indefinitely without clear and significant consequence to the facility. Therefore, in today's rulemaking, EPA is proposing to add a safeguard to part 75 to ensure that this does not happen. A new paragraph 75.33(d) would be added, which would make it a violation of the primary measurement requirement of § 75.10(a) to allow the annual monitor data availability to drop below 80.0 percent for SO_2, NO_X, flow rate, or CO_2. Based on an analysis conducted on data availability information for the third quarter of 1996, EPA believes that affected facilities will easily be able to comply with the 80.0 percent data availability criterion (see analyses in Docket A–97–35, Item II–B–16). The results of that analysis indicated a mean percent monitor data availability of 96.9 percent for SO_2, 95.0 percent for NO_X, and 96.6 percent for flow rate. Although there were 13 (out of 995 total) SO_2 monitors, 21 (out of 997 total) flow monitors, and 46 (out of 1365 total) NO_X monitoring systems with percent monitor availabilities below 80.0 percent in the 4th quarter of 1996, the Agency expects that many of these systems would be exempt from the prohibition based on a limited number of operating hours in the previous year (see Docket A–97–35, Item II–A–8).

The proposed prohibition would not apply to units that have only a limited number of operating hours (less than 3000 hours of operation in the previous 12 calendar quarters) because such units can have a low data availability percentage without necessarily having extended monitor downtime incidents. In addition, no violation would occur if the low monitor availability is caused by a sudden and reasonably unforeseeable event beyond the control of the owner or operator (such as destruction of monitoring equipment by fire or flood). The owner or operator would, however, be required to notify the Administrator, in writing, within 7 days of the occurrence of such catastrophic events and also to provide notification to the EPA Regional Office and to the appropriate State agency. The owner or operator would be further required to submit a corrective action plan, including an implementation schedule. Thus, this proposed prohibition should not result in violations of part 75, except for situations involving poor operation and maintenance practices, which are clearly *not* beyond the control of the owner or operator.

Another option considered by the Agency was to modify the standard missing data algorithms for SO_2, NO_X, and flow rate as follows. Under this option, the algorithms for monitor data availabilities of 90.0 percent to 100.0 percent would remain unchanged. The algorithms currently used for *all* monitor data availabilities below 90.0 percent would be retained, but these would apply only to data availabilities between 80.0 percent and 89.9 percent. Finally, a new algorithm would be added for monitor data availabilities below 80.0 percent. When the data availability drops below 80.0 percent, the appropriate *maximum* substitute data value would have to be used (i.e., the maximum potential concentration for SO_2 or CO_2, the maximum NO_X emission rate, or the maximum potential flow rate). EPA believes that requiring maximum values to be reported when the data availability drops below 80.0 percent would provide incentive to the affected sources to keep their monitors well-maintained. Because any changes to the standard missing data algorithms would require software modifications, this option, if adopted, would not take effect until January 1, 2000. The Agency has not proposed this option because it would require software changes for all affected units even though very few units have data availabilities that fall below 80.0 percent. The Agency seeks comment, however, on whether this option should be used instead of the proposed prohibition given that it is more consistent with the structure of the missing data requirements in part 75 and would be self-implementing without any need to initiate enforcement actions to achieve the desired result of continued high data availabilities that assure accurate reporting of emissions.

The Agency also emphasizes that the required data availability for the Acid Rain Program would remain at 100.0 percent even if the proposed prohibition is adopted, meaning that substitute data would have to be supplied for any periods in which data from a certified monitoring system are not available. This approach is in sharp contrast to most other CEMS programs that do not rely on substitute data. In those programs, the Agency, as well as State and local agencies, expect and often require much higher data availabilities than 80.0 percent. Based on the number of units with data availability higher than 95.0 percent under the Acid Rain Program, CEMS data availability less than 95.0 percent may well indicate a failure to properly operate and maintain a CEMS. Many agencies rely on that 95.0 percent availability level to target systems for inspection and other compliance-related follow-up actions. In addition, agencies have adopted various required minimum data availabilities for CEMS that far exceed the 80.0 percent level selected for the prohibition proposed in today's rulemaking.

It is also important to note that monitor availability under part 75 and monitor downtime under other programs are not always the same. Under part 75, a source may have actual monitoring data that are suspect, based on an evaluation of various quality assurance activities. In this situation, the owner or operator may, as a conservative measure, report substitute data rather than the actual data. In contrast, this type of missing data substitution does not occur under most other programs. In most programs, the suspect data would simply be invalidated and no emission data would be reported for those hours.

Therefore, because of the structure of the missing data provisions in the Acid Rain Program and the generally applicable economic incentive to achieve high data availabilities under part 75, it would be improper to equate the proposed prohibition in today's rulemaking with a required minimum data availability requirement established for other programs that do not have the same features. The Agency does not intend that this proposed provision should serve as a precedent for evaluating the appropriate achievable data availability for other programs. Consistent with current practices, the Agency would continue to expect CEMS to achieve high data availability and that, generally, monitor downtime in excess of 5.0 percent may warrant appropriate investigation and follow-up activities.

G. General Authority to Grant Petitions Under Part 75

Background

Section 75.66(a) provides generally that a designated representative of a unit subject to part 75 may submit a petition to the Administrator. Sections 75.66(b) through (h) address petitions to the Administrator on the specified topics of alternative flow monitoring methods, alternatives to standards incorporated by reference, alternative monitoring systems, parametric monitoring procedures, missing data for units with add-on emission controls, emission or heat input apportionments, and the partial recertification process. Each of these subsections set forth the items which must be included with a particular type of petition. In addition, § 75.66(i) states that, for any other petition to the Administrator under part 75, the designated representative for an affected unit shall include sufficient information for the evaluation of such petition.

Discussion of Proposed Changes

Today's proposal would revise § 75.66(a) to state clearly that the designated representative of an affected unit may petition the Administrator for authorization to apply an alternative to any requirement under part 75 or incorporated by reference in part 75, regardless of whether another section of part 75 explicitly allows such a petition concerning the particular requirement. EPA views this change as a clarification to the general authority already provided by §§ 75.66(a) and (i). The proposed rule would also be amended to include new paragraphs (i) through (l), which would set forth the specific requirements for other petitions that are explicitly allowed by other sections of the rule but which are not currently included in this section. In addition, the proposed rule, at § 75.66(m), would also indicate the appropriate documentation to be submitted for petitions under subsection (a), except those under subsections (b) through (l), where the required documentation is already specified. The required documentation in subsection (m) would be: (1) Identification of the unit; (2) information explaining why the proposed alternative should be used instead of the existing part 75 provision; (3) descriptions and, if applicable, diagrams of the equipment and procedures to be used in the proposed alternative; and (4) information demonstrating that the proposed alternative is consistent with the purposes of the provision for which an alternative is requested and is consistent with the purposes of part 75 and of section 412 of the Act.

Rationale

As presently codified, EPA is concerned that the rule does not state clearly what types of petitions may be submitted under § 75.66. In particular, existing subsection (i) could be interpreted as referring only to petitions that are mentioned in other sections of part 75 and that are not specifically listed in § 75.66(b) through (h). EPA has not interpreted § 75.66(i) in this manner. In administering the Act, EPA has inherent discretion to grant *de minimis* exceptions from statutory or regulatory requirements, where EPA determines that holding the regulated entity to the applicable requirement would yield a gain of trivial or no benefit, provided Congress has not unambiguously demonstrated its intent to foreclose such exceptions. *See, e.g., Public Citizen* v. *Young,* 831 F.2d 1108, 113 (D.C. Cir. 1987); *Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360–61 (D.C. Cir. 1979). Since the issuance of part 75 in 1993, EPA has accepted, and, in some cases exercised its discretion and granted, petitions under § 75.66 that requested exceptions and that were not specifically referenced in § 75.66(b) through (h) or elsewhere in part 75 (see Docket A–97–35, Item II–B–17). Such petitions have included, for example, a request to set a CO_2 span lower than that required by part 75 in order to more accurately quality assure the CO_2 monitor. Another petition requested an alternative to the requirement to perform an annual RATA on a unit that was scheduled to shutdown, prior to the deadline for performing the RATA, in order to install a scrubber, construct a new stack, and install and certify new CEMS. A petition was also submitted for permission to use a propane sampling frequency as specified in the State operating permit and to then calculate SO_2 emissions by using the highest sulfur content recorded during the previous 365 days and report these data in quarterly reports. These petitions were submitted for the purpose of requesting alternatives to various requirements of part 75, even though the ability to petition the Agency on these issues was not referenced explicitly in other sections of part 75 or in § 75.66(b) through (h). In most cases, the circumstances leading to the request for an alternative to a part 75 requirement were not anticipated during the drafting of part 75 regulations. In fact, today's proposal revises several part 75 requirements to allow for alternatives that were originally requested and approved through the petition process set forth in § 75.66. The Agency continues to believe that the general provision allowing petitions for alternatives to part 75 requirements is necessary to enable EPA to address circumstances that were not foreseen during the development of such requirements. This is important since circumstances can sometimes vary significantly from boiler to boiler. While the response to comment document for the January 11, 1993 rule (see Docket A–91–69, Item V–C–1, Issue # M–8.8.2) might be read to bar petitions for exceptions from any provision of part 75, EPA maintains that such a reading would be inconsistent with the regulatory language of §§ 75.66(a) and (i) that allow such petitions, and with the established practice of the Agency in administering part 75.

The existing § 75.66(i) states that for petitions other than § 75.66(b) through (h) petitions submitted under the section, the designated representative should include sufficient information for the evaluation of the petition. No other information is provided concerning the contents of such petitions. As §§ 75.66(b) through (h) all provide a list of the type of information that should be included in petitions submitted under the respective sections, the Agency believes that, in addition to amending § 75.66(a) to clarify that petitions may be submitted for circumstances that may not be covered by other sections authorizing petitions to the Administrator, it is appropriate to provide units with a list of the type of information that should be included with the petition. Similarly, EPA believes that it is appropriate to add to the section provisions setting forth the information requirements for those petitions that are explicitly allowed under other sections of part 75 but that are not listed in the existing § 75.66. All these revisions would make the petition process more uniform and minimize confusion regarding what information EPA would require in order to accept and consider any petition for an alternative to a part 75 requirement.

H. NO_X Mass Monitoring Provisions for Adoption by NO_X Mass Reduction Programs

Background

Part 75 contains requirements for monitoring NO_X emissions with a continuous emission monitoring system or other approved method. Owners and operators are required to calculate hourly, quarterly average, and annual average NO_X emission rates (in lb/mmBtu). Part 75, however, currently contains no requirements for reporting NO_X mass emissions (in tons). Other NO_X emission reduction programs being developed pursuant to title I of the Act (such as the NO_X Budget Program in the Ozone Transport Region) are expected to require reporting of NO_X mass emissions from many of the units affected under the Acid Rain Program. To streamline reporting burdens under multiple programs and to allow for the administration of multi-state NO_X mass trading programs, the Agency believes it appropriate to amend part 75 to include provisions for monitoring, recording, and reporting NO_X mass emissions that could apply to such trading programs. These provisions would provide standard procedures—resulting in precise, reliable, accessible, and timely emissions data—that could be adopted under a state or federal NO_X mass emission reduction program. To the extent that these standard provisions are adopted, the burden on industry would be reduced and the administration of the programs would be facilitated, in that the Agency or implementing states would not need to develop NO_X mass monitoring provisions anew and industry would not need to become familiar with multiple approaches to NO_X mass monitoring.

Discussion of Proposed Changes

The proposed NO_X mass emissions provisions would apply only where EPA, states, or groups of states incorporate them and mandate their use through a separate regulatory action. The proposed amendments would make changes to §§ 75.1, 75.2, 75.4, 75.16, 75.17, Appendix D, section 2.1.2.2, and Appendix F, section 5.5. They would also add a new subpart H containing new §§ 75.70, through 75.73 and a new section 8 in Appendix F containing sections 8.1, 8.1.1, 8.1.2, 8.1.3, 8.1.4, 8.2, 8.3, 8.3.1, and 8.3.2.

Section 75.1, the purpose and scope section, would be amended to broaden the scope by adding that part 75 will also set forth provisions for monitoring and reporting NO_X mass emissions that EPA, states, or groups of states may require sources to use to demonstrate compliance with a NO_X mass emission reduction program. Section 75.2 would be amended to add that the provisions of part 75 may also apply to sources subject to a state or federal NO_X mass emission reduction program.

The compliance date section, § 75.4(a), would be altered to state that the provisions relating to monitoring and reporting of NO_X mass emissions become applicable on the deadlines specified in the applicable state or federal NO_X mass emission reduction program requiring the use of part 75 to monitor and report NO_X mass emissions.

Section 75.16 would be amended to state that title IV affected units using the provisions of part 75 to monitor and report NO_X mass emissions under a state or federal NO_X mass emission reduction program would have to meet the heat input monitoring and determination requirements in both § 75.16 and in subpart H, §§ 75.71 and 75.72. Section 75.17 would be amended to state that title IV affected units using the provisions of part 75 to monitor and report NO_X mass emissions under such a program would have to meet the NO_X emission monitoring and determination requirements in both § 75.17 and subpart H, §§ 75.71 and 75.72.

The applicable procedures for the monitoring and determination of NO_X mass emissions would be added in proposed subpart H, §§ 75.70, 75.71, and 75.72 and corresponding recordkeeping and reporting requirements would be set forth in § 75.73.

Section 75.70 would set forth the general requirements including: definitions, compliance dates, incorporation by reference, initial certification and recertification procedures, quality assurance and quality control requirements, substitute data requirements, and requirements regarding petitions. In general these provisions for monitoring NO_X mass would mirror the provisions for monitoring of SO_2, NO_X, and CO_2 for compliance with title IV. However, because the program would be a state program, rather than a federal program, there would be some differences in the administrative requirements. These differences would be most pronounced for units that were not subject to Acid Rain emission limitations and were not already subject to the provisions of part 75. The major differences in administrative requirements would involve the process for petitioning under § 75.66 and the process for certifying and recertifying monitors. Under the existing Acid Rain Program, the Administrator must approve all petitions under § 75.66. Under this proposal, petitions for units that were only subject to the provisions of part 75 because they were subject to a state or federal NO_X mass emission reduction program, would have to be approved by both the permitting authority for the applicable NO_X mass program and the Administrator. The permitting authority would also be responsible for reviewing and approving or disapproving certification and recertification applications for such units.

Section 75.71 sets forth the general monitoring methodologies that would be allowed for different types of units. The proposal would require units to determine hourly NO_X mass emissions (in lb) by monitoring NO_X emission rate (in lbs/mmBtu) and heat input (in mmBtu/hr) on an hourly basis and by multiplying those two values and the hourly unit operating time (in hour or fraction of an hour) together. Coal units and other units that burn solid fuel and that are covered by subpart H would be required to measure NO_X emission rate using a NO_X emission rate CEM consisting of a NO_X concentration CEM and a diluent CEM (CO_2 or O_2 CEM) and to measure heat input using a diluent CEM and a continuous volumetric flow monitor. All gas- and oil-fired units covered by subpart H would be allowed to use that approach or, alternatively, could measure NO_X emission rate using a NO_X emission rate CEM and heat input by using a fuel flowmeter and performing fuel sampling and analysis. This alternative for determining heat input from gas- and oil-fired units is set forth in Appendix D of part 75. Gas and oil units that qualify as either peaking units or low mass emission units under part 75 would also have additional lower cost monitoring methodologies available to them. Peaking units, for example, would have the option to do source testing to create heat input versus NO_X emission rate correlation curves. Then, based on hourly measurement of heat input from a fuel flowmeter and fuel sampling and analysis using the provisions in Appendix D to part 75, the heat input vs NO_X emission rate correlation curves would be used to estimate the hourly NO_X emission rate. This rate would be used in conjunction with hourly measured heat input to determine NO_X mass. A unit that qualifies as a low mass emission unit would have the option to use a fuel-type and boiler-type specific default NO_X emission rate and the unit's maximum rated hourly heat input to determine NO_X mass emissions. The low mass emissions unit provisions are in proposed § 75.19.

Section 75.72 sets forth the specific requirements for monitoring emissions at units that share common stacks and/or common pipes, for units that emit to multiple stacks and for units that receive fuel from multiple pipes. These provisions mirror similar provisions in § 75.16 for monitoring SO_2 mass emissions from similar units and groups of units.

Appendix D, section 2.1.2.2 would indicate that the heat input apportionment procedures of that section would not be applicable for units whose compliance with this part is required under a NO_X mass emissions reduction program. Instead, the unit would have to meet the heat input monitoring and determination requirements in subpart H, §§ 75.71 and 75.72.

The applicable procedures for calculating NO_X mass emissions would be added in proposed section 8 of Appendix F. Section 8.1 of Appendix F contains proposed equations for determining hourly NO_X mass emissions, section 8.2 contains proposed equations for determining quarterly, cumulative annual and ozone season NO_X mass emissions, and section 8.3 contains specific provisions for monitoring NO_X emissions from a common stack. Additionally, revisions to section 5.5 of Appendix F would indicate that the heat input calculation procedures of section 5.5.3 would not be applicable for units whose compliance with this part is required under a NO_X mass emissions reduction program.

Rationale

(a) *Authority to Propose NO_X Mass Provisions.* The authority for the proposed NO_X mass provisions rests in two separate portions of the Act. First, section 412(a) states that the owner or operator of an affected source under title IV must monitor and quality assure data for sulfur dioxide and nitrogen oxide for each affected unit at the source. 42 U.S.C. 7651k(a). This section does not limit the nitrogen oxide data requirement to emission rate data in lb/mmBtu or to data necessary for compliance with emission limits established under title IV. Indeed, oil- and gas-fired units have been required to report NO_X emission rate data under part 75 even though only existing coal units are subject to NO_X emission limits under title IV. (*See* 58 FR 3590, 3644, January 11, 1993). Thus, the Agency believes that providing for reporting NO_X mass emissions under part 75 is an appropriate exercise of the authority under section 412, particularly since NO_X mass emissions reporting may be required under a separate applicable requirement.

Second, independently of the authority granted by section 412, section 114(a) of the Act gives the Administrator broad authority to collect data for ''the purpose of developing or assisting in the development of any implementation plan under section 110 or 111(d)'', ''of determining whether any person is in violation of any such standard or a requirement of such a plan'', or ''carrying out any other provision of [the] Act'' (except certain provisions of title II concerning mobile sources). Section 114 is, of course, not limited to sources that are affected units under title IV. Moreover, section 301(a)(1) authorizes the Administrator ''to prescribe such regulations as are necessary to carry out his functions'' under the Act, including the functions specified in section 114. Thus, EPA maintains that the Agency is authorized to adopt provisions in part 75 that could govern monitoring of NO_X mass emissions, especially where such information is expected to support States' efforts to attain ambient air quality standards.

From a policy perspective, now is the appropriate and most efficient time to adopt these changes. In July 1997, EPA Administrator Carol Browner announced a series of initiatives to reform environmental data management and collection (see Docket A–97–35, Item II–I–21). The new initiatives are intended to streamline reporting requirements and increase coordination across different programs that affect the same sources. There are a number of examples of ongoing efforts to streamline the reporting of emissions for utility units. One example is a proposal to revise the NSPS NO_X standards for utility and industrial boilers subject to reporting under 40 CFR part 60. That proposal would allow facilities to submit NSPS reports through part 75 reporting (see 62 FR 36948, July 9, 1997). Another example is the Ozone Transport Commission's NO_X Budget program. That program is expected to require utility sources and certain industrial sources in the northeast to reduce emissions of NO_X through a trading program similar to the Acid Rain SO_2 trading program. On January 31, 1996, the OTC released the Model Rule which outlines procedures for the monitoring and reporting of NO_X mass emissions; these procedures are based on the monitoring and reporting requirements set forth in part 75 (see Docket A–97–35, Items II–I–7 and II–I–22). Today's proposal would facilitate the coordination of reporting under the Acid Rain Program and NO_X mass programs like the OTC NO_X Budget Program.

In addition, the Agency believes it is appropriate to include these requirements in the current proposal because the Acid Rain affected units may be undertaking DAHS software changes to respond to the other proposed revisions to part 75 if they are adopted. The Agency would enable facilities to coordinate the necessary software changes by proposing the revised reporting requirements to allow for NO_X mass emission reporting at this time along with the other part 75 revisions. Although EPA is proposing this requirement now to facilitate software changes, the requirement to actually record and report NO_X mass emission data under part 75 generally would not become effective for any unit unless and until a program requiring such recording and reporting is implemented for that particular unit (EPA notes that, as discussed elsewhere in Section III.C.4. of this preamble, a limited group of title IV affected units (i.e., low mass emissions units) would be required to record and report NO_X mass emissions for purposes of the Acid Rain Program.) In addition, if a state elected to require the use of these requirements to support a state NO_X mass emission monitoring and reporting requirement, these requirements would not become federally enforceable until those requirements were approved by EPA as part of the SIP.

(b) *Monitoring Methodology.* The proposed requirement would require sources to determine NO_X mass as a function of hourly average NO_X emission rates, heat input rates, and unit operating time. EPA is proposing this approach because it accurately accounts for NO_X mass emissions without requiring any changes to the current missing data routines and quality assurance requirements in part 75. An alternative to this approach, not included in today's proposal, would be to measure total mass emissions using a NO_X pollutant concentration monitor, a volumetric flow monitor and unit operating time, analogous to the approach taken currently for SO_2 emissions. This methodology would have two advantages: first, there would be less missing data from a NO_X pollutant concentration monitor than from a NO_X CEMS which (under the existing and proposed rule) contains both a NO_X pollutant concentration monitor and a diluent monitor; and second, it would avoid possible overestimation from a bias adjustment factor applied to the NO_X system to correct bias in the diluent monitor (see Docket A–97–35, Item II–D–96).

However, this methodology would also have a number of disadvantages. In order to monitor NO_X as total mass emissions using a NO_X pollutant concentration monitor and a volumetric flow monitor, several major changes would need to be made to part 75. The entire concept of a NO_X CEMS—and the quality assurance tests and missing data procedures associated with the NO_X CEMS—might need to be revised, to include either a NO_X CEMS with only a NO_X pollutant concentration monitor and a DAHS (in which case, a separate flow monitoring system would also be required in order to determine NO_X mass), or a NO_X CEMS with a NO_X pollutant concentration monitor, a volumetric flow monitor, and a DAHS. Since the relative accuracy standard currently in part 75 for NO_X systems is in lb/mmBtu, it would be necessary to establish a new relative accuracy standard for NO_X concentration in ppm if the NO_X/flow method described above were incorporated into the final rule. Bias adjustment would also have to occur on the newly defined NO_X CEMS. It would also be necessary to create a missing data procedure either for NO_X concentration in ppm or for hourly NO_X mass emission rate in lb/hr. Hourly NO_X mass emission rate would be calculated using the same formula as for SO_2 mass emission rate (Equation F–1 or F–2), only using a constant of 1.194 x 10^{-7}(lb/scf)/ppm NO_X. In addition, this methodology would not easily support the monitoring and reporting of NO_X emission rate data in lb/mmBtu.

Therefore, in order to meet the emission rate reporting requirements, affected sources under title IV would still be required to maintain a diluent CEMS and the current NO_X emission rate missing data procedures. The Agency has not proposed this approach because it does not believe that the benefits of slightly reduced amounts of missing data for NO_X mass and removal of the bias adjustment factor for the diluent monitor justify the complication of having two separate procedures for monitoring NO_X emissions from a given unit. Nevertheless, the Agency requests comment on whether this approach to measuring mass emissions should be used in lieu of the proposed heat input and emission rate approach for sources required to report NO_X mass.

(c) *Common Stack and Pipe Monitoring.* The Agency notes that the proposed procedures for monitoring NO_X emission rate at a common stack to determine NO_X mass emissions under the proposed § 75.72 procedures are different than the procedures currently allowed for monitoring NO_X emission rate in § 75.17. The Agency is concerned that the § 75.17 provisions would be too imprecise for measuring NO_X mass emissions because the two values used to determine NO_X mass emissions (NO_X emission rate and heat input) are not required to be measured at the same location. In the existing rule, NO_X emission rate may be monitored at the unit level in the duct leading to the common stack and heat input can be determined from measurements at the common stack and then apportioned to the individual units using unit load. While this heat input apportionment method has been allowed for Acid Rain purposes, it is not accurate in all cases because it does not account for different heat rates from the units exhausting to the common stack and does not account for differences in operating time at the units. It has been allowed by the Agency for Acid Rain purposes because apportioned heat input determined under § 75.16 (e) had only a limited effect on emissions trading (i.e., on the SO_2 allowance program). Although apportioned heat input determined under § 75.16(e) is used to determine compliance with the reduced utilization provisions of the Acid Rain Program, the apportioned heat input estimate was deemed accurate enough for that purpose and for the relatively small number of units and short period involved. Determinations of reduced utilization are required only for Phase I units during 1995–1999 and for opt-in units. However, for purposes of a NO_X mass trading program, the heat input value would be used in the calculation to determine NO_X mass, and an imprecise unit level heat input value could cause the NO_X mass emissions from some units to be underestimated. The NO_X mass trading program could be undermined by the lack of a consistent emissions value for each NO_X allowance. Therefore, the proposed provisions for monitoring heat input and NO_X emission rate from units in a NO_X mass trading program would be similar to the provisions that are currently used for monitoring SO_2 mass emissions at a common stack at § 75.16. The provisions for monitoring SO_2 mass emissions require that the two values needed to determine SO_2 mass emissions, stack flow rate and SO_2 concentration, be monitored at the same location. The Agency is proposing that, for purposes of determining NO_X mass emissions, a facility could use the same location options currently available for SO_2: the facility could either monitor both NO_X emission rate and heat input at the common stack level or monitor them both at the unit level. The Agency is also proposing a third option: heat input could be monitored at the unit level and summed to the common stack level, while NO_X emission rate could be monitored at the common stack level. Even though this option would allow NO_X emission rate and heat input to be measured at different locations, it does not have the inherent inaccuracies described above because it does not require heat input apportionment.

Similarly, the optional procedures currently allowed for the apportionment of heat input measured at a common pipe in Appendix D, section 2.1.2.2 are not available for units with a common pipe under subpart H. As discussed above for common stacks, the Agency is concerned that the heat input apportionment under Appendix D, section 2.1.2.2 provisions would be too imprecise for the purpose of calculating NO_X mass emissions. In the existing rule, heat input can be determined from measurements at the common pipe and then apportioned to the individual units using unit load. For purposes of calculating NO_X mass emissions under subpart H for a unit which is supplied fuel from a common pipe, the measurement of fuel flow rate would have to be made at the pipe leading to the individual unit in order to determine unit level heat input.

The Agency solicits comment on the proposed approach for monitoring NO_X mass emissions at a common stack or pipe and whether it is appropriate to mirror the common stack and pipe provisions for SO_2 mass emissions.

(d) *Multiple duct/stack monitoring.* The current provisions for monitoring NO_X emission rate, in §§ 75.17(c)(1) and (2), allow the owner or operator to determine NO_X emission rate for a unit that exhausts through multiple ducts or stacks using a Btu-weighted sum of the NO_X emission rates measured in each duct or stack or by monitoring NO_X emission rate in only one duct or stack. The new proposed § 75.72 would set forth specific requirements for monitoring NO_X mass in multiple ducts or stacks and would in some cases place a number of limits on the options in § 75.17(c) and in some cases not allow the options in § 75.17(c). The proposed options for monitoring NO_X mass are similar to the existing provision in § 75.16(d) for monitoring SO_2 mass emissions at multiple ducts/stacks. They are also similar to the provisions being used in the OTC NO_X Budget Program to determine NO_X mass in similar situations.

The new proposed § 75.72 does not contain an option for any units to use a Btu-weighted sum of the NO_X emission rates measured in each duct or stack. The reason that this option is not appropriate is that in order to use this option to determine a unit's NO_X emission rate, the owner or operator of the unit would have to monitor both NO_X emission rate and heat input in each duct or stack. (As discussed above, the heat input apportionment method allowed under § 75.17 is not sufficiently accurate for a NO_X mass program.) These two values allow the calculation of NO_X mass and, therefore, there is no reason to determine a Btu-weighted sum for purposes of this subpart.

The new proposed § 75.72 would not allow coal units to monitor NO_X emission rate in only one duct or stack. The proposal would also not allow gas and oil units to monitor the NO_X emission rate in only one duct or stack, unless heat input is determined using the provisions of Appendix D to this part and the owner or operator makes a demonstration that the emission rate would always be the same in both ducts or stacks. Reasons that the emission rate might vary include the use of add-on emission controls in the ducts or stacks or venting of emissions to one duct or stack and not the other.

These limitations are required for monitoring mass emissions (in lbs), but are not necessary for monitoring emission rate (in lbs/mmBtu) at coal units or gas and oil units that use continuous volumetric flow monitors, because, for reasons discussed above, monitoring mass requires the monitoring of both emission rate and heat input. Since the amount of stack flow that is vented to each duct or stack could vary significantly depending upon the location and use of dampers and induction fans in the ducts or stacks, it is necessary to measure volumetric flow in both ducts or stacks in order to determine heat input for the unit(s). In order to accurately use these heat input values to determine NO_X mass, it is also necessary to measure NO_X emission rate in both ducts or stacks. Therefore, proposed § 75.72 would require monitoring of heat input and NO_X emission rate in both ducts or stacks for coal units and gas-and oil-fired units that use continuous volumetric flow monitors and exhaust to multiple ducts or stacks.

Since gas-and oil-fired units that are using the procedures in appendix D of part 75 to determine heat input based on fuel consumption do not have to measure volumetric flow in the duct or stack in order to determine heat input, EPA believes it is appropriate to allow these units to measure NO_X emission rate in only one duct or stack if they can demonstrate to both the permitting authority and the Administrator that the NO_X emission rate in either duct or stack is representative of the NO_X emission rate in each duct or stack. Therefore, proposed § 75.72 allows gas- and oil-fired units that are using the procedures in appendix D of part 75 to measure NO_X emission rate in only one duct or stack if they can demonstrate to both the permitting authority and the Administrator that the NO_X emission rate in either duct or stack is representative of the NO_X emission rate in each duct or stack.

(e) *Reporting of NO_X* Mass Emissions. The Agency also notes that the proposed procedures differ in two key respects from the way data is currently reported under part 75. The first difference is that the proposal would require reporting of hourly NO_X mass emissions, in lbs, (instead of hourly mass emission rate, in lb/hr, as is currently required for the reporting of SO_2 under part 75). The OTC NO_X Budget Program is expected to require the reporting of hourly mass emissions, in lb, rather than hourly mass emission rates, in lb/hr, because of experience under the Acid Rain Program with reporting hourly SO_2 and CO_2 mass emission rates. As discussed in Section III.R.1 of this preamble, the reporting of hourly SO_2 and CO_2 mass emission rates has been a source of some confusion in the implementation of the Acid Rain Program. For the reasons presented in Section III.R.1 of this preamble, EPA is not proposing to change the existing SO_2 and CO_2 reporting requirements. However, the existing part 75 does not require any NO_X mass emission reporting, and in order to avoid the problems experienced under the Acid Rain Program and to be consistent with the OTC NO_X Budget Program, EPA proposes here to base the new NO_X reporting on mass emissions in pounds. Maintaining consistency with the provisions expected to be adopted for the OTC NO_X Budget Program is important to ensure that a central body such as EPA would be able to effectively administer the program if states opted to participate in a multi-state NO_X trading program larger than the Ozone Transport Region covered by the OTC NO_X Budget Program.

The second key difference is that, in addition to reporting a quarterly and cumulative annual total emissions value, the proposed revisions would also require reporting of a cumulative ozone season total value. Generally, the ozone season extends from May 1 to September 30 of every year. The cumulative ozone season emissions would be reported with the second quarter and third quarter reports submitted to EPA. The reason that reporting would be required on an ozone season basis is that one of the main reasons the data is being collected is to support other programs designed to control emissions during the ozone season.

(f) *Role of EPA and States/Localities in Administering the Monitoring Portion of a NO_X* Trading Program. The Agency also notes that another important potential difference between the use of this part to support the Acid Rain Program under Title IV of the CAA and the use of this part to support other NO_X mass emission reduction programs is the role that EPA and the state or local permitting authority that may establish such a program will play. Under the Acid Rain Program, even though many states have assumed the role of the permitting authority under Phase II of the program, EPA still retains authority to issue approvals and disapprovals related to all of the monitoring and reporting issues, such as certification of monitoring systems under § 75.20, approval of petitions under § 75.66 and approvals of alternate monitoring petitions under § 75.48. EPA believes that if a NO_X mass emission reduction program is approved as part of a SIP or if EPA agrees to work with individual or groups of states to help administer the monitoring and reporting portion of a NO_X mass emission reduction program, EPA would still have to be involved in the approval process.

The level of this involvement might vary depending upon the specific type of approval or disapproval. It also would vary depending upon whether or not the unit had an Acid Rain emission limitation. For instance, EPA would play a significant role in the approval of an alternate monitoring petition under § 75.48 or any other petitions under § 75.66. For a unit with an Acid Rain emission limitation, any petition would already have to be approved by EPA. In order to streamline the process for these sources, EPA believes that EPA should continue to issue approvals and disapprovals of petitions. However, since sources would also be using the monitored data to meet SIP requirements, EPA would take this action in consultation with the applicable state. For units that are not subject to an Acid Rain emission limitation, EPA would still need to be involved in petition determinations. There are two primary reasons that this involvement would be necessary. The first would be as part of EPA's typical role in assuring that any alternative to the approved SIP will still result in the air quality benefit that would have been derived if the permitting authority had not deviated from the SIP. The second would be as part of EPA's role in administering the emissions tracking portion of a NO_X mass emission reduction program. If EPA was not involved and a state approved, for a unit, an alternative that allowed variations to the reporting requirements, EPA might not be able to administer the emissions tracking portion of the program for that unit. Similarly, for approval and disapproval of certification applications and recertification applications, EPA believes that there should be two separate requirements; one for units subject to an Acid Rain emission limitation, and one for units not subject to an Acid Rain emission limitation. For units subject to an Acid Rain emission limitation, EPA would still approve or disapprove certification and recertification applications. This would streamline the process for units since they would only have to deal with one regulatory agency for both programs. For units not subject to an Acid Rain emission limitation, the permitting authority would approve certification and recertification applications. EPA requests comment on this approach and whether the respective roles of the Administrator and the permitting authority should be different for units that are subject to both an Acid Rain emission limitation and to a NO_X mass emission reduction program and for units that are subject solely to a NO_X mass emission reduction program.

I. Span and Range Requirements

Background

The span and range requirements for part 75 continuous emission monitoring systems are found under section 2.1 of Appendix A to the January 11, 1993, rule, as amended on May 17, 1995. Sections 2.1.1, 2.1.2, 2.1.3 and 2.1.4 of Appendix A give the specific span and range requirements for SO_2 monitors, NO_X monitors, diluent (O_2 and CO_2) monitors, and flow rate monitors, respectively.

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 should be an approximation, based on the type of fuel being combusted, 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. Part 75 span values are used to determine the appropriate reference gas concentrations and reference signals for daily calibration of the CEMS; the reference concentrations and signal values 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 to the January 11, 1993 rule specified procedures for determining the span values for four parameters: 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 results from the previous 12 months (using the highest sulfur content and lowest heating value in Equation A–1a or A–1b). The SO_2 span value was then obtained by multiplying the MPC by 1.25 and rounding the result upward to the next highest multiple of 100.0 ppm. The MPC values for NO_X were specified in the rule and were based on the type of fuel being combusted (e.g., 800.0 ppm for coal-firing and 400.0 ppm for oil-firing). The NO_X span value was then determined by multiplying the MPC by 1.25 (e.g., 1000.0 ppm for coal-firing and 500.0 ppm for oil-firing). 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 either using Equation A–3a (or A–3b) or from historical test data (i.e., from velocity traverses conducted at or near maximum load). Then, the span value was obtained by multiplying the MPV by 1.25 and rounding the result upward to the next highest multiple of 100 feet per minute (fpm).

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 were used to reduce SO_2 emissions), a second, ‘‘low-scale’’ span and range would be required. The low scale of the CEMS would be defined as 1.25 times the ‘‘maximum expected concentration’’ (MEC). The original rule was prescriptive regarding the method of determining the MEC. For SO_2, the MEC was to be calculated using Equation A–2; for NO_X, an MEC value of 320.0 ppm was to be used for coal-firing and 160.0 ppm for oil-or gas-firing.

In the first two years of Acid Rain Program implementation, it became increasingly clear to both the regulated community and to EPA that the span and range provisions of part 75 lacked sufficient flexibility and clarity. The NO_X provisions were particularly problematic, being overly prescriptive in some instances and sometimes requiring two spans and ranges when a single, appropriately-sized range would suffice. Also, the units of the flow rate span were expressed in terms of velocity (i.e., feet per minute), and this was not consistent with either the units of measure used for daily monitor calibrations or the units used for electronic reporting of flow rate data.

The May 17, 1995 rule attempted to address these deficiencies, as follows. For SO_2, an alternative means of determining the MPC, in lieu of using historical fuel sampling data, was added; the MPC could be based upon 30 days of historical CEMS data. The use of historical CEMS data was also allowed as an option for MEC determinations, instead of using Equation A-2. For NO_X, the method of determining the MPC was made less prescriptive. First, 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. The MPC value from this list could be used in lieu of the fuel-based MPC prescribed in the original rule. Second, two alternative methods of determining the MPC or MEC were added, i.e., from historical CEMS data or from emission test results. Finally, flexibility was added to the dual-range requirements for NO_X monitors so that, in many instances, the span and range requirements of part 75 could be met on a site-specific basis, using a single span and range.

The span provisions for CO_2 and O_2 were not significantly changed in the May 17, 1995 rule. For flow rate, however, a more detailed procedure for determining the span value was added. This addition was considered necessary because during the first year of program implementation it came to light that there are actually two important span values associated with flow rate: (a) the ‘‘calibration’’ span value used for daily calibrations, and (b) the ‘‘flow rate’’ span value in units of standard cubic feet per hour (scfh). These two span values are both derived from the MPV, but are almost invariably expressed in different units of measure, and, therefore, the two spans are generally not equal numerically. For instance, the calibration span value for the daily calibration of a differential pressure-type flow monitor, expressed in units of inches of water, is a small number (generally less than 5.0 in. H_2O); while the flow rate span value, in scfh, is a very large number, usually in the tens or hundreds of millions.

The May 17, 1995 rule also revised the procedures for adjusting the span and range of SO_2, NO_X, and flow monitors. Sections 2.1.1.4, 2.1.2.4, and 2.1.4 of Appendix A to the original rule had specified that span and range adjustments were required whenever the MPC, the MEC, or the MPV changed significantly. 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 revised sections 2.1.1.4, 2.1.2.4, and 2.1.4 of Appendix A to 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. Finally, the May 17, 1995 rule specified that whenever the range of a gas monitor is adjusted, a linearity test is required, and a calibration error test must be done when the range of a flow monitor is adjusted.

Discussion of Proposed Changes

Since promulgation of the May 17, 1995 rule, EPA has continued to receive questions and comments about the span and range sections of part 75. Many of the questions and comments have centered on the adjustment of span and range. The following questions are typical: When must the span and range be changed? What constitutes a ''significant'' change in the MPC, MEC, or MPV? When a span and range adjustment is required, what are the deadlines for making the changes and for completing the required linearity test? How should full-scale exceedances be reported? There also appears to be some lingering confusion and misunderstanding about how to determine the flow rate span values and how to calculate the maximum potential flow rate (MPF) and the NO_X maximum emission rate (MER) (see Docket A–97–35, Items II–B–8, II–D–67, and II–E–31). In view of this, EPA believes that the span and range sections of the rule are still not sufficiently clear, flexible, or detailed and are in need of further revision. In June, 1996, a national part 75 CEM Implementation Workgroup meeting was held in Washington D.C. to discuss possible revisions to part 75. One of the principal topics of discussion was span and range (see Docket A–97–35, Item II–E–32). Today's rulemaking proposes comprehensive revisions to sections 2.1 through 2.1.4 of Appendix A, based in part on the discussions of the June, 1996 meeting. The principal changes are described in paragraphs (1) through (5), below.

1. Maximum Potential Values

The basic procedure for determining the maximum potential of SO_2 concentration would be unchanged by today's proposal. However, two new provisions would be added to section 2.1.1.1 of Appendix A to prevent overestimation of the MPC. The first of these provisions would allow the exclusion of clearly anomalous fuel sampling results when determining the MPC. The second provision would apply to units for which the designated representative certifies that the highest sulfur fuel is never combusted alone, but is always blended or co-fired with other fuel(s) during normal operation. For such units, the MPC would be calculated using best estimates 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. The best estimates of the highest percent sulfur and lowest GCV for a blend or fuel mixture would be derived from weighted-average values based upon the historical composition of the blend or mixture in the previous 12 (or more) months.

The alternative procedure for determining the MPC of SO_2 based upon quality assured historical CEMS data would be retained, but it is proposed that the MPC be based, at a minimum, upon the previous 720 quality assured monitor operating hours, rather than the previous 30 unit operating days. This is to ensure that a sufficient quantity of valid data is used for the MPC determination. Making the determination based on 30 unit operating days does not provide that assurance, particularly for units that may only operate for a few hours a day (e.g., peaking units). Revised section 2.1.1.1 would also specify that for a unit with add-on SO_2 emission controls, the historical CEMS data option may only be selected if the certified SO_2 monitor used to determine the MPC is located at the control device inlet.

For NO_X, the general procedures for determining the MPC would also remain the same, i.e., either: (1) use the MPC value prescribed in the original rule, (2) use the unit-specific value listed in Table 2–1 or 2–2, or (3) determine the MPC by emission testing or from historical CEM data. However, the following changes to section 2.1.2.1 of Appendix A are proposed. First, a statement would be added that the MPC would have to be based upon the combustion of whichever fuel or blend combusted at the unit produces the highest level of NO_X emissions. Second, an advisory statement would be added, noting that the initial MPC value determined for a unit that is not equipped with low-NO_X burners (LNB) would have to be re-evaluated if a low-NO_X burner system is subsequently installed and optimized. Third, if historical CEMS data are used to determine the MPC, the determination would have to be based on the previous 720 (or more) quality assured monitor operating hours (instead of the previous 30 unit operating days). Fourth, units with add-on NO_X emission controls could only use the historical CEM data option if the historical data represented uncontrolled emissions (e.g., if the certified CEMS used to collect the data were located prior to the control device inlet or, for a unit with seasonal NO_X controls, if the historical data were from a period when the controls were not operating). Fifth, if emission testing is used for the MPC determination, sufficient tests would have to be performed at various loads and excess oxygen levels to ensure that a credible MPC value is obtained. For units with add-on NO_X emission controls, the emission test data would have to be collected upstream of all controls, or, for a unit with seasonal controls, during a period when the controls were not operating. Finally, a specific requirement to calculate the maximum potential NO_X emission rate (MER) would be added to section 2.1.2.1 of Appendix A. The May 17, 1995 rule had provided a definition of the MER in § 72.2; however, a corresponding requirement to calculate the MER was not included in part 75 at that time. The MER is occasionally needed to provide substitute NO_X emission rates during missing data periods. The owner or operator would be permitted to 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.

For CO_2, today's proposed rule would add a new section 2.1.3.1 to Appendix A, which provides a definition of the MPC. The MPC for CO_2 pollutant concentration monitors would be 14.0 percent for boilers and 6.0 percent CO_2 for combustion turbines. Alternatively, the MPC could be based on a minimum of 720 hours of representative quality assured historical CEM data.

For flow rate, the procedure for determining the MPV would be essentially unchanged by today's proposed rule, i.e., the MPV would either be determined from Equation A–3a (or A–3b, as applicable) in Appendix A, or it would be based on velocity traverse data taken at or near maximum load. However, a procedure for calculating the maximum potential flow rate (MPF) would be added to section 2.1.4.1 of Appendix A. The MPF is occasionally used to provide substitute flow rate data; therefore, a clear, consistent method of determining the MPF is needed.

2. Maximum Expected SO_2 and NO_X Concentrations

Today's proposal would significantly change the procedures for determining the maximum expected concentration (MEC) of SO_2. The purpose of the revisions would be to ensure that the proper span(s) and range(s) are selected for SO_2 measurement. Proposed section 2.1.1.2 of Appendix A would require the MEC to be determined for units with SO_2 controls and also for uncontrolled units that burn both high- and low-sulfur fuels (or blends) as primary or backup fuels (e.g., high- and low-sulfur coal or different grades of fuel oil).

The revised procedures for determining the MEC for SO_2 would be as follows. For units with emission controls, Equation A–2 in Appendix A would be used to calculate the MEC. For uncontrolled units that burn both high-sulfur and low-sulfur fuels or blends as primary or backup fuels, Equation A–1a or A–1b in Appendix A (which in the current rule is reserved for MPC calculations) would be used to determine an MEC value for each fuel or blend, with three important exceptions. The MEC would not be calculated for: (1) the highest-sulfur fuel or blend (because it would be duplicative of the MPC calculation); (2) fuels or blends with a total sulfur content no greater than the total sulfur content of natural gas, i.e., ≤ 0.05 percent sulfur by weight, because § 75.11(e)(3)(iv) of the current rule specifies that natural gas combustion does not trigger a dual span and range requirement for the SO_2 monitor (for gas firing, the MEC and low-scale span values would be too low to be practical for quality assurance purposes, e.g., < 5 ppm for pipeline natural gas); and (3) fuels or blends that are combusted only during unit startup, because such fuels are infrequently used and are not representative of normal unit operation.

Today's proposal would continue to allow the same flexibility in the SO_2 MEC determination that was introduced in the May 17, 1995 rule. That is, if a certified SO_2 CEMS is already installed, the owner or operator could determine the MEC based upon historical continuous monitoring data, in lieu of using mathematical equations. If this option were chosen for a unit with SO_2 controls, the MEC would be the maximum SO_2 concentration measured at 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 both high- and low-sulfur fuels or blends as primary and backup fuels and have no SO_2 controls, the MEC for each fuel would 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.

Today's rule also proposes to change the way in which the MEC is determined for NO_X. Revised section 2.1.2.2 of Appendix A would require a determination of the MEC during normal operation for units with add-on NO_X controls capable of reducing NO_X emissions to 20.0 percent or less of the uncontrolled level (i.e., steam injection, water injection, selective catalytic reduction or selective non-catalytic reduction). 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. The MEC would be determined in one of three ways: (1) using Equation A–2 in Appendix A; or, if that equation is not appropriate, (2) by emission testing or (3) by using historical CEMS data from the previous 720 (or more) quality assured monitor operating hours. Revised section 2.1.2.2 would give specific guidelines and procedures by which to obtain the MEC when the emission testing or CEMS data options are selected. All CEMS or emission test data used for the MEC determination would be taken under stable operating conditions with all control devices and methods operating properly.

3. *Span and Range Values*

For SO_2, NO_X, and flow rate, respectively, revised sections 2.1.1.3, 2.1.2.3 and 2.1.4.2 of Appendix A would allow the high-scale span value to be between 100.0 and 125.0 percent of the maximum potential value (i.e., the MPC or MPV), rounded off appropriately. This is a change from the current rule which requires the high span to be set at 125.0 percent of MPC or MPV, rounded off appropriately. However, the change is not expected to be disruptive, because properly sized span values previously determined by multiplying the MPC or MPV by 1.25 could continue to be used. The change would allow the owner or operator to set the span value in such a way that a small exceedance of MPC or MPV would not require a span change (see paragraph 5, ''Adjustment of Span and Range,'' below). The added flexibility in span selection would also allow different units with similar (but not identical) MPCs for SO_2 and/or NO_X to use the same span value and to use the same calibration gas concentrations, which could result in cost savings for some facilities. In 1996, EPA received and approved a petition from one utility to equalize the SO_2 span values at several of its coal-fired units (see Docket A–97–35, Items II–C–23, II–D–71).

For CO_2 and O_2 monitors, today's proposal would revise section 2.1.3 of Appendix A to allow the owner or operator maximum flexibility in selecting an appropriate span value. The CO_2 or O_2 span value would not be determined in the same way as an SO_2, NO_X, or flow rate span value. Rather, for CO_2 monitors installed on boilers, any convenient span value between 14.0 percent and 20.0 percent CO_2 representing the percent diluent in the flue gas would be acceptable. For combustion turbines, any 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. However, if the O_2 concentrations are expected to be consistently below 15.0 percent, an alternative span value of less than 15.0 percent could be used, provided that an acceptable technical justification was included in the monitoring plan. The proposed rule would also allow purified instrument air containing 20.9 percent O_2 to be used as the high level calibration gas for oxygen monitors having span values greater than or equal to 21.0 percent O_2.

There are two principal reasons why EPA is proposing increased flexibility in the selection of the CO_2 and O_2 span values. The first is to encourage greater accuracy in the diluent gas measurements. The revisions would allow the span value to be customized so that the concentration of the upscale calibration gas used for daily calibrations can be as close as possible to the actual average CO_2 or O_2 concentrations in the stack. In 1996, EPA received and approved a petition from one utility to use a CO_2 span value of 15.0 percent for its coal-fired units, rather than the 20.0 percent span value required by part 75 (see Docket A–97–35, Items II–C–20, II–D–68). The second reason for revising the CO_2 and O_2 span requirements is to eliminate unnecessary high-level span and range requirements. The current rule requires a high span value of 20.0 percent for all CO_2 and O_2 monitors. However, there are many units (e.g., combustion turbines) for which the diluent gas concentrations are so low that the guideline in the current section 2.1 of Appendix A (i.e., that the majority of the readings be within 25.0 to 75.0 percent of full-scale) cannot be met unless a second, low-scale span and range are used. For most of these units, there are technical and safety reasons why the diluent concentrations must remain low; therefore, it is unreasonable to require a high range to be maintained if a lower range will suffice and can never be exceeded. During the Phase II certification process, EPA approved CO_2 span values of 10.0 percent for a number of combustion turbines and waived the high-scale range requirement (see Docket A–97–35, Items II–C–19, II–C–21, II–D–64).

Today's proposal would not change the basic way in which the full-scale range setting of a monitor is determined. The range would still have to be set greater than or equal to the span value. However, the guideline for selecting an appropriate full-scale range in section 2.1 of Appendix A would be revised as follows. With few exceptions, the full-scale range would be selected so that, to the extent practicable, the readings during typical unit operation fall between 20.0 and 80.0 percent of full-scale; this represents a slight increase in flexibility from the ''25-to-75 percent of full-scale'' guideline in the current rule. Today's proposal would also emphasize that section 2.1 is only a guideline and would cite three specific cases in which it is inapplicable. Specifically, the guideline would not apply to: (1) quality assured SO_2 readings obtained during the combustion of natural gas or fuel with equivalent total sulfur content (because the resulting SO_2 emissions are too low to be subject to the span and range requirements); (2) quality assured 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 (because the high range is not the normal operating range for the unit); and (3) quality assured SO_2 or NO_X readings 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 are associated with periods of high control device efficiency (because it is not necessary to re-range a monitor based on non-representative hours of exceptional control performance).

For flow monitors, today's rule proposes to revise section 2.1.4.2 of Appendix A to more clearly define the ''calibration span value'' (which is the span expressed in the units of measure used for the daily calibrations) and the ''flow rate span value'' (which is the span expressed in the units used for electronic data reporting, i.e., scfh). The proposed rule defines these two span values in considerable detail and outlines how to use them. EPA believes that this will result in greater consistency in implementation of the part 75 flow rate monitoring requirements.

4. Dual Span and Range Requirements for SO_2 and NO_X

In today's rule, revisions are proposed to the dual span and range requirements for SO_2 and NO_X monitors in sections 2.1.1.4 and 2.1.2.4 of Appendix A. The revised provisions are essentially the same for both pollutants. 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 determined under revised section 2.1.1.2 or 2.1.2.2 of Appendix A would be compared against the maximum potential concentration (MPC) determined under proposed sections 2.1.1.1 or 2.1.2.1. If this comparison shows any of the MEC values to be < 20.0 percent of the MPC, a low-scale span would be required. If several of the MEC values are found to be < 20.0 percent of the MPC, then the low-scale span would be based upon whichever MEC value is closest to 20.0 percent of the MPC. The low-scale span value would be determined in a manner similar to the high-scale span, i.e., by multiplying the MEC by a factor between 1.00 and 1.25 and rounding off the result appropriately.

When both a high-scale span and a low-scale span are required for SO_2 or NO_X, proposed sections 2.1.1.4 and 2.1.2.4 would allow the owner or operator to use either of the following monitor configurations to meet the dual-range requirement: (1) a single analyzer with two ranges, or (2) two separate analyzers connected to a common probe and sample interface. The use of other monitoring configurations would be subject to the approval of the Administrator. The monitor configurations would be represented in the monitoring plan as follows: (a) the high and low ranges could be designated as two separate, primary monitoring systems; (b) the high and low ranges could be designated as separate components of a single, primary monitoring system; or (c) one range (the ''normal'' range) could be designated as a primary monitoring system, and the other range as a non-redundant backup monitoring system. The high and low ranges would be quality assured according to their designation in the monitoring plan. Primary monitoring systems would have to meet the QA requirements for primary systems in § 75.20(c), Appendix A, and Appendix B, with the following exception: relative accuracy test audits (RATAs) would be required only on the normal range. For units with emission controls, the low range would be considered normal; for other units, the range in use at the time of the scheduled RATA would be considered normal. Non-redundant backup systems would have to meet the applicable QA requirements for ''like-kind replacement analyzers'' in proposed § 75.20(d).

Today's rule would add a new alternative provision under sections 2.1.1.4 and 2.1.2.4 of Appendix A for dual-span units with SO_2 or NO_X emission controls. The new provision 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 (based on uncontrolled emissions). This value would be reported whenever the SO_2 or NO_X concentration exceeded the full-scale of the low-range analyzer. The default high-range value is being proposed for controlled units that seldom, if ever, experience full-scale exceedances of the low monitor range during normal operation (e.g., units that have a permit condition requiring cessation of unit operation when a full-scale exceedance occurs or units that experience low-range exceedances only during startup). EPA solicits comment on the proposed approach of using a default high-range value in lieu of a high range monitor and on the value of the default.

EPA specifically requests comment on whether the proposed dual-span monitoring configurations, monitoring system designations, and quality assurance requirements are adequate, or whether there are additional configurations (e.g., one range with two spans, two separate analyzers with separate probes, etc.) that should be included in the rule.

Finally, when two spans and ranges are required, proposed revised sections 2.1.1.4 and 2.1.2.4 of Appendix A would specify that the low range would have to be used to record emission data when the SO_2 or NO_X concentrations are expected to be consistently below 20.0 percent of the MPC (i.e., when a fuel or blend with a MEC value < 20.0 percent of the MPC is combusted). And if the full-scale of the low range is exceeded, the high range would be used to record data (or, if applicable, the default high range value would be reported).

5. *Adjustment of Span and Range*

In today's rule, detailed guidelines and procedures are proposed for adjusting the span and range of the CEMS in revised sections 2.1.1.5, 2.1.2.5, 2.1.3.2 and 2.1.4.3 of Appendix A. The intent of these provisions is to ensure that each owner or operator assesses the adequacy of all CEMS span values on at least a quarterly basis (and whenever operational changes are planned) and, based on that assessment, makes any necessary adjustments to the spans or ranges in a timely manner. EPA believes that the proposed procedures are sufficiently flexible so that frequent span and range adjustments will not be necessary. The procedures are primarily directed at CEMS with improperly-sized spans and ranges, to bring them into full conformance with part 75 requirements or for future changes in unit operation (e.g., fuel switch or low-NO_X burner installation) that may significantly affect the level of emissions or flow. All required span or range adjustments would have to be made no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, unless the span change would require new calibration gases to be ordered for daily calibration error and linearity tests, in which case, the owner or operator would have up to

90 days after the end of the quarter to make the span adjustment.

The revised procedures for span and range adjustment would be as follows. First, if the maximum value upon which the high span value is based (i.e., the MPC or, for flow rate, the MPF) is exceeded during a calendar quarter, but the span is not exceeded, the span or range would not have to be adjusted. However, for missing data purposes, if any quality assured hourly concentration or flow rate exceeds the MPC or MPF by ≥ 5.0 percent during the quarter, a new MPC or MPF would have to be defined, equal to the highest value recorded during the quarter, and a monitoring plan update would be required. Second, for the high measurement range, if any quality assured reading 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, equal to the highest on-scale reading recorded during the quarter, and the span value would also have to be changed. If the new span value exceeded the current full-scale range setting, then a new range setting would also be required. Similar span adjustment requirements would apply to the low scale if the two measurement ranges are used separately for distinctly different modes of operation (e.g., during the combustion of different fuels), rather than being used in combination to provide a continuum of measurement range capability.

The proposed procedures for responding to full-scale exceedances are as follows. Whenever the full-scale of a high monitor range is exceeded, excluding hours of non-representative operating conditions (e.g., a trial burn of a new fuel), corrective action would be required to adjust the span and range. In addition, any time the range is exceeded, 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. The Agency believes that 200.0 percent of the range is sufficiently conservative to ensure that emissions would not be under-reported. One utility that experienced a full-scale exceedance of the high SO_2 monitor range estimated from the results of fuel sampling that the SO_2 concentration was approximately 150.0 percent of full-scale during the incident (see Docket A–97–35, Item II–D–24).

For units with two span values and two measurement ranges for a particular parameter (e.g., SO_2), when the full-scale of the low range is exceeded, provided that the high monitor range is available to record emission data, no corrective actions would be required. However, if, at the time of the low-range exceedance or during the continuation of the low-range exceedance, the high range is either out-of-service or out-of-control for any reason (and therefore is not available to record quality assured data), the MPC would have to be reported until the readings either returned to the low scale or until the high scale returned to service and was able to provide quality assured data. However, if the reason the high scale is unavailable is because of a high scale exceedance, 200.0 percent of the high range value would be reported for each hour of the exceedance.

Proposed sections 2.1.1.5(e), 2.1.2.5(e), and 2.1.4.3(e) of Appendix A would require that the monitoring plan be updated whenever changes are made in the maximum potential values, maximum expected values, span values, or full-scale range settings. The updates would be made in the quarter in which the changes become effective. The proposed sections 2.1.1.5(e) and 2.1.2.5(e) of Appendix A would further require a linearity test to be done whenever the span of a gas monitor is adjusted, if the span change is significant enough to require new calibration gases for daily calibration error tests and linearity checks. Finally, proposed sections 2.1.4.3(c) and (d) of Appendix A would require a calibration error test to be done whenever a flow monitor span or range is adjusted (unless the adjustment requires a significant change to the flow monitor that would require recertification under § 75.20(b)).

J. Quality Assurance/Quality Control (QA/QC) Program

1. QA/QC Plan

Background

Section 1 of Appendix B to part 75 as originally promulgated on January 11, 1993 sets forth provisions for developing and implementing a quality control program. As part of the quality control program, section 1 requires that the source develop and maintain a quality control plan that documents how the equipment used to report emissions data for part 75 is maintained and quality assured. While the provisions in sections 1.1, 1.2, and 1.4 of Appendix B to part 75 are applicable only to continuous emissions monitoring systems, the provisions in sections 1.3 and 1.5 of the existing rule are more generally applicable to all monitoring systems under part 75. The quality assurance requirements for excepted monitoring systems under Appendices D and E and for alternative monitoring systems under subpart E are provided in the respective Appendices or subpart of part 75, as revised; however, specific guidelines for the quality control plans for these systems are not given.

Based on the experience of state and EPA inspectors at Acid Rain field audits, there has been confusion and inconsistency among industry sources regarding the contents of the quality control plan. In some cases, utility staff have requested further guidance from EPA on what the quality control plan should contain. Based on this experience, the Agency believes that the quality control program provisions in section 1 of Appendix B need to be revised. Specifically, the rule needs to be clarified in two areas: (1) the applicability of the QA/QC program (i.e., do the provisions apply to all monitoring systems, only to CEMS, or only to specific excepted or alternative monitoring systems?); and (2) the recordkeeping requirements for repair and maintenance events. In addition, several utilities have asked EPA to consider deleting the requirement to maintain an inventory of spare parts, which they believe to be unnecessary and burdensome.

Discussion of Proposed Changes

The proposed revisions discussed in this section affect section 1 of Appendix B to part 75. The terms ''quality control program and plan'' would be changed to ''quality assurance/quality control program and plan.'' The scope of section 1 would be expanded to include QA/QC program provisions for excepted monitoring systems under Appendices D, E, and I and alternative monitoring systems under subpart E. Section 1 would also be reordered to separate the requirements applicable to all monitoring systems (section 1.1) from the requirements specific to CEMS (section 1.2). The preventative maintenance provisions, in section 1.3 of the existing rule, would be moved to section 1.1.1 of the proposal, and would be revised to delete the requirement to maintain an inventory of spare parts. A new section 1.1.3 would be added to specify the requirements for maintaining records of testing, maintenance, and repair activities. QA/QC program requirements specific to excepted monitoring systems under Appendices D, E, and I would be added in section 1.3. These provisions would require written procedures to be maintained for fuel flowmeter testing, primary element inspection, and fuel sampling and analysis as well as requiring a description of equipment and records of testing to be maintained. Section 1.3.6 would make the recordkeeping requirements consistent with the quality assurance requirements of section 2.3.1 of Appendix E. Section 1.3.7 would specify which QA/QC program requirements apply for excepted monitoring systems under Appendix I. Finally, section 1.4 would define the QA/QC program requirements for alternative monitoring systems approved under subpart E, based on the quality assurance requirements of subpart E.

Rationale

The Agency believes that the manner in which quality assurance/quality control (QA/QC) and maintenance-related activities are performed can have a significant effect upon the accuracy of the data reported by a monitoring system. Therefore, today's proposal seeks to ensure that adequate records are kept to document that each monitoring system and its ancillary components is being maintained and operated in a proper manner. Section 1 in Appendix B to part 75 would, therefore, be amended to provide sources with General guidance regarding QA/QC program requirements. However, the Agency recognizes that QA/QC programs may vary from site to site and that many sources have already developed and implemented an effective QA/QC program. It is the Agency's intent to allow each source the flexibility to develop and implement a QA/QC program that will result in the reporting of accurate emissions data through proper equipment calibration, maintenance and troubleshooting procedures.

(a) *Inventory of Spare Parts.* Section 1.3 of Appendix B to part 75 in the January 11, 1993 rule requires that an inventory of spare parts be maintained as part of the QA/QC program. The intent of this requirement is one of the fundamental goals of a QA/QC program, i.e., to maximize the availability of quality-assured data from the monitoring system. Since maintenance and repairs are required in order to keep the monitoring system operating properly, the need for replacement parts will arise over the term of use of the monitoring equipment. In order to minimize the amount of time when the system is unable to provide data because a new part is needed, the existing rule requires that the source maintain an inventory of spare parts. The Agency has received comments on this requirement from both affected utilities and from state inspectors arguing that it is unnecessary and cumbersome (see Docket A–97–35, Item II–D–49, II–E–28). Commenters have suggested that different approaches have been effectively employed to ensure that spare parts are available in a timely manner; however, not all of these approaches require that an inventory of spare parts be kept on-site. For example, some spare parts may be available on a very timely basis from a local supplier, making it unnecessary to maintain spare parts on-site. The Agency believes that these different approaches may be adequate substitutes for keeping an on-site inventory of spare parts. Therefore, the requirement to maintain an inventory of spare parts would be removed in today's proposal, although the objective of an effective QA/QC program, i.e., to maximize data availability, would not change.

(b) *Maintenance Records.* The Agency believes that maintaining records of monitoring system maintenance and repairs is an essential component of an effective QA/QC program. Several utilities have indicated that they agree and have instituted QA/QC programs which include maintaining such records (see, e.g., Docket A–97–35, Item II–D–88). However, some EPA and state inspectors have found that not all sources keep adequate records of maintenance and repairs in their QA/QC program. EPA believes that this failure to keep adequate records compromises the effectiveness of the QA/QC program. Therefore, today's proposal would require each source to maintain proper records of all testing, maintenance, or repair activities performed on any monitoring system or component. Additionally, today's proposal would require that these records and any additional supporting documentation be made available for review during an audit.

(c) *Excepted Monitoring System Requirements.* The required quality assurance activities for excepted monitoring systems are set forth in the respective Appendices D, E, or I. Today's proposed revisions in section 1.3 of Appendix B would specify that information on the approved methods, test procedures and test results must be maintained on-site suitable for inspection as part of the QA/QC program. The proposed revisions would consolidate all of the QA/QC requirements in Appendix B rather than having them spread out in Appendices D, E, and I.

2. Flow Monitor Polynomial Coefficient

Background

Many of the stack gas volumetric flow rate monitors currently in use by affected sources use software polynomial coefficients to convert electrical signals from the monitors into flow rate values that are electronically reported to the Acid Rain Division. The flow rate values generated from these monitors are used by the source's data acquisition and handling system (DAHS) to compute hourly mass emission rates of SO_2, CO_2, and hourly heat input rates. Currently, affected sources are not specifically required to report, record, or document the numerical values of the polynomial coefficients used by their flow monitors.

Discussion of Proposed Changes

Proposed § 75.59(a)(5)(vi) and proposed revisions to section 1.1.3 of Appendix B would require the current values of the flow monitor coefficients to be recorded and would require records to be kept of any changes or adjustments to the coefficient values. The proposed revisions in § 75.20(b) define flow monitor coefficient adjustment as an event which requires recertification.

Rationale

(a) *Recordkeeping of Coefficients.* The agency has recently become aware (by a comment received in response to a request for review of the Acid Rain Audit Manual) of a potentially serious omission in the flow monitor recordkeeping requirements of part 75 (see Docket A–97–35, Item II–D–92). The commenter indicated that part 75 lacks a requirement to document the values of the polynomial coefficients which are programmed into the software of most flow monitoring devices, and that the Acid Rain CEM audit manual does not recommend that Agency or state auditors check the coefficient values. The values of the polynomial coefficients are important because they are directly related to the accuracy of a flow monitor. The coefficient values are usually established at three different load levels (low, mid, and high), in a process called ''linearization'' or ''characterization'' of the monitor. Linearization is done in an attempt to ensure that the flow monitor reads accurately across all load levels. The Agency agrees with the commenter that the flow monitor variables are a critical component of the flow monitoring system and that the adjustment of those variables represents a significant change to the flow monitoring system. Therefore, today's rulemaking proposes to add § 75.59(a)(5)(vi) to require owners and operators of affected sources to record the numerical values of the flow monitor polynomial coefficients used during initial certification of the monitor and during each subsequent relative accuracy test audit (RATA). In addition, section 1 of Appendix B to part 75 would be revised to require that any changes to the flow monitor polynomial coefficients be documented and maintained as part of the QA/QC program maintenance records. Section 1 of Appendix B would also be changed to require the source to document procedures related to the adjustment of flow monitor variables in its QA/QC plan. The values of the flow monitor coefficients and the related adjustment procedures would be required to be kept on-site, in a format suitable for review by an inspector during an audit.

(b) *Recertification After Adjustment of Coefficients.* Since changing the flow monitor polynomial constants relinearizes the instrument, significantly altering the monitored reading, today's proposed rule would amend § 75.20(b) to require recertification subsequent to any flow monitor polynomial coefficient change. Since a three level RATA is the only part 75 quality assurance test that checks the linearity of a flow monitor, the recertification would require a three level RATA.

K. Calibration Gas Concentration for Daily Calibration Error Tests

Background

All part 75 gas monitoring systems are required by section 2.1.1 of Appendix B of the current rule to pass daily calibration error tests, in order to validate emission data from the CEMS. The procedures for conducting the daily calibration error tests are found in section 6.3.1 of Appendix A. Each daily calibration error test consists of injecting two protocol gases of known concentration into the CEMS and comparing the responses of the instrument to the tag values of the protocol gases. The two required gas concentrations for the calibration error tests are zero-level (i.e., 0.0 to 20.0 percent of the span value of the instrument) and high-level (80.0 to 100.0 percent of span).

The span values of part 75 SO_2 and NO_X monitors are determined by multiplying the maximum potential concentration (MPC) by 1.25 and rounding the result upward to the nearest 100.0 ppm. For CO_2 and O_2 monitors, a span value of 20.0 percent O_2 or CO_2 is prescribed. These span values have been deliberately oversized to prevent full-scale exceedances from occurring. Consequently, the SO_2, NO_X, CO_2, and O_2 readings obtained during normal unit operation are generally well below the span values and typically range from about 25.0 to 75.0 percent of full-scale. Because of the oversized span values, the concentrations of the high-level calibration gases used for daily calibration error tests are often much higher than the actual pollutant and diluent gas concentrations in the stack. As a result, the representativeness of the daily calibration error test can be questioned, because the test does not always check the accuracy of an analyzer on the part of the scale where most of the readings occur. For instance, typical CO_2 concentrations for many part 75 units range from about 10.0 to 12.0 percent CO_2 (i.e., 50.0 to 60.0 percent of the span value). However, when CO_2 analyzers are calibrated, the high-level calibration gas concentrations (i.e., 16.0 to 20.0 percent CO_2) are considerably higher than normal stack emissions. In view of this, EPA believes it would be appropriate to allow the owner or operator to have greater flexibility in selecting a representative upscale gas for daily calibrations. One State agency has successfully implemented this type of flexibility in its CEM program. The State's CEM rule specifies the acceptable range of values for the upscale calibration gas, but adds the following qualifying statement, ''* * *unless an alternative concentration can be demonstrated to better represent the normal source operating levels *–*–*'' (see Docket A–97–35, Item II–D–72).

Discussion of Proposed Changes

Today's rule proposes to add flexibility to the procedures for conducting the calibration error tests of part 75 gas monitors to encourage daily calibrations to be done more representatively. Section 6.3.1 of Appendix A would be revised so that, beginning on January 1, 2000, either the mid-level gas (50.0 to 60.0 percent of span) or the high-level gas (80.0 to 100.0 percent of span) could be used as the upscale calibration gas for daily calibration error tests. A corresponding change would be made to the procedure for calculating the calibration error in section 7.2.1 of Appendix A. Prior to January 1, 2000, the owner or operator would have the option of using the mid-level calibration gas for daily calibrations if it better represents the typical stack gas concentrations than the high-level gas.

L. Linearity Test Requirements

Background

Section 75.20(c) of the current part 75 rule requires a 3-point linearity test of each SO_2 and NO_X pollutant concentration monitor and each diluent gas (O_2 or CO_2) monitor, as part of the initial certification process. A linearity test consists of a series of nine reference calibration gas injections at three different known concentration levels (low, mid, and high) to establish the accuracy of a gas analyzer across its measurement range. The procedures for conducting linearity tests are found in section 6.2 of Appendix A to part 75. Section 6.1 of Appendix A specifies that linearity tests must be done while the unit is operating.

After the initial certification of a gas monitoring system, section 2.2 of Appendix B to part 75 requires periodic linearity tests to be performed. A linearity check is required during each unit operating quarter or, for bypass stacks, during each quarter in which flue gases are discharged through the stack. For units with two span values for a particular parameter (e.g., units with add-on SO_2 controls), linearity tests must be conducted on both the ''low'' and ''high'' monitor ranges. Successive linearity tests are, to the extent practicable, to be conducted no less than 2 months apart.

Utility representatives have asked EPA to consider changing the requirement for the unit to be operating when linearity tests are done (see Docket A–97–35, Items II–D–20, II–D–65, II–E–13, II–E–14). This has been requested because owners and operators of peaking units and other units that operate on an ''on-call'' basis have experienced difficulty in complying with the requirement for the unit to be on-line during linearity tests. For instance, a unit may only operate for a few hours in a quarter and not be needed again until the next quarter. In such a situation, the utility might be forced to re-start and operate the unit (whether or not it is needed) to comply with the linearity test requirement. Some of the utility representatives have also expressed the opinion that for certain monitoring technologies (e.g., dry extractive), on-line and off-line linearity tests are essentially equivalent.

Discussion of Proposed Changes

1. Unit Operation During Linearity Tests

Today's rule proposes to revise the linearity test requirements of part 75 to make them easier with which to comply. EPA agrees that the current linearity test requirements of part 75 lack flexibility and that compliance with the requirements is particularly difficult for infrequently operated units. However, the Agency does not agree with the utility representatives that have suggested allowing off-line linearity tests as the best solution to the problem. Nor is the Agency proposing to allow technology-specific exemptions to the on-line linearity test requirement.

Rather, today's proposal would retain the requirement for linearity tests to be performed while the unit is combusting fuel at conditions of typical stack temperature and pressure. A clarifying statement would be added to section 6.2 of Appendix A, indicating that the unit does not have to be generating electricity during the test. But EPA would continue to require that a linearity test be performed while the unit is combusting fuel at conditions of typical stack temperature and pressure in order to test the monitoring system under the same conditions as when the monitor is measuring emissions, in order to account for any temperature and pressure effects. An on-line linearity test challenges a CEMS while it is in equilibrium with the stack environment and has been sampling stack gas continuously for a period of time.

2. Linearity Test Frequency

The Agency proposes instead to add flexibility to the linearity test requirements by changing the basis upon which the frequency of linearity tests is determined and by providing a linearity grace period. In today's proposal, section 2.2 of Appendix B would be revised to require that a linearity test be performed in each ''QA operating quarter'' rather than in each ''unit operating quarter'' or ''bypass stack operating quarter.'' For linearity tests, a QA operating quarter would be defined in the same way as for RATAs, i.e., as a calendar quarter in which the unit operates for at least 168 hours (or, for common stacks, a quarter in which effluent gases discharge through the stack for at least 168 hours). EPA believes that the QA operating quarter methodology would, in most instances, enable the owner or operator of a peaking unit or other infrequently operated unit to complete an on-line linearity test within the calendar quarter in which it is due. However, the following additional changes would be made to further ensure that the linearity test requirements can be met: (1) the requirement to perform successive linearity tests at least 2 months apart would be reduced to allow successive tests to be done one month (30 days) apart; and (2) a new section, 2.2.4, would be added to Appendix B, providing a 168 unit operating hour grace period after the end of each QA operating quarter in which to complete the required test. Thus, to make it easier for infrequently operated units to complete the required linearity tests in the quarters in which they are due, the required waiting time between successive linearity tests would be reduced. And, if circumstances should prevent a linearity test from being completed in the QA operating quarter in which it is due, the test could be done during the grace period. If the required linearity test were not completed by the end of the grace period, data from the monitor would be considered invalid from the hour after the grace period expires until the hour of completion of a subsequent successful linearity test.

For infrequently operated units, certain calendar quarters would not qualify as QA operating quarters. Therefore, in accordance with today's proposed rule, no linearity tests would be required in those quarters. However, this exemption from linearity testing would not be without limit. Proposed section 2.2.2 of Appendix B would allow no more than four consecutive calendar quarters to elapse following the quarter in which the last linearity test was conducted, without a subsequent linearity test having to be performed. That is, a linearity test would either have to be done by the end of the fourth consecutive elapsed calendar quarter since the last test or within a 168 unit operating hour grace period after the end of the fourth consecutive elapsed quarter. Data from the monitor would become invalid if the linearity test was not completed by the end of the grace period and would remain invalid until a linearity test was successfully completed.

Today's proposal would also change the requirement for units with two span values for a particular parameter (e.g., units with add-on SO_2 controls) to perform quarterly linearity tests on both the low and high monitor ranges. Section 2.2.1 of Appendix B would be revised to require a linearity test of a monitor range only if that range is used to report data during the QA operating quarter. However, under proposed section 2.2.3(e) of Appendix B, at least one linearity test of each range would still be required every four calendar quarters to maintain data validation on the range.

3. Linearity Test Method

Today's proposal would add two new requirements to section 6.2 of Appendix A: (1) that all linearity tests must be done ''hands-off,'' meaning that no adjustments of the CEMS other than certain calibration error adjustments would be permitted prior to or during the linearity test period; and (2) to the extent practicable, each linearity test would have to be completed within a period of 24 unit operating hours. These proposed provisions are intended to ensure greater consistency in the way in which linearity tests are conducted and to ensure that the tests are completed in a timely manner. The allowable calibration adjustments prior to and during a linearity test would be defined in proposed section 2.1.3 of Appendix B. For a further discussion, see Section O of this preamble, ''CEM Data Validation,'' below.

4. Exemptions

Finally, section 6.2 of Appendix A would be revised to exempt SO_2 and NO_X monitors with span values of 30 ppm or less from the linearity test requirements of part 75. At these low span values, the linearity test begins to lose its significance. For example, typical low, mid, and high calibration gases for a span value of 30.0 ppm would be 24.0 ppm, 18.0 ppm, and 9.0 ppm, respectively. The appropriate linearity performance specification in section 3.2 of Appendix A is ± 5.0 ppm at each calibration gas level. Therefore, in this illustration, the monitor reading could be 14.0 ppm for both the ''low'' and ''mid'' gases or 20.0 ppm for both the ''mid'' and ''high'' gases. Even though a valid straight line comparing the reference gas concentrations and the monitor readings cannot be constructed from such data, the monitor would still appear to pass the linearity test.

M. Flow-to-Load Test

Background

The current quality assurance requirements for flow rate monitoring systems in Appendices A and B to part 75 include daily calibration error tests, daily interference checks, quarterly leak checks (for differential pressure type monitors only), and semiannual or annual relative accuracy test audits. 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 purports to check flow monitor accuracy, but, as explained below, the ability of the test to accomplish this objective is somewhat questionable.

There is a distinct difference between the daily calibration error test of a flow rate monitor and the calibration error test of a gas monitor. To calibrate a gas monitor, a protocol gas of known concentration is sent through the monitoring system and analyzed. This generally serves as a reliable indicator of the system's ability to accurately measure pollutant or diluent gas concentrations, because the calibration closely simulates the sampling and analysis of stack gas by the monitoring system. A flow monitor calibration error test, on the other hand, does not provide the same level of assurance of data quality. Generally, a flow monitor calibration 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 is not a ''true'' calibration of the monitor, since it does not evaluate the system's ability to measure an actual stack gas flow rate. In order to perform true daily flow monitor calibrations, two reference stack gas flow rates would have to be generated and measured. Practical considerations preclude such calibrations from being done, however, because the unit load level would have to be significantly varied during each operating day, and suitable reference method measurements (e.g., velocity traverses using EPA Method 2) would have to be made daily at each calibration load level.

Because of the limited usefulness of the flow monitor daily calibration error test, 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. For instance, the sensors of DP and thermal-type monitors are subject to plugging and/or fouling, which will cause the monitors to read lower than true and can result in under-reporting of emissions. One utility observed a substantial increase in the readings from its flow monitor after the sensors were cleaned during a unit outage. Apparently, the sensor problems had not been detected by the daily calibration error tests (see Docket A–97–35, Item II–E–29). A second utility experienced a gradual deterioration of the monitor's performance in the 9-month period following the RATA. By the sixth month (at load levels and CO_2 concentrations virtually identical to the conditions at the time of the RATA), the flow monitor readings were consistently 15.0 to 20.0 percent lower than the baseline average flow rate measured by EPA Reference Method 2 during the RATA. However, during the 9-month period, the flow monitor had consistently passed its daily calibration error tests (see Docket A–97–35, Item II–B–11). During a State inspection of a third utility, the inspector observed a consistent 20.0 to 30.0 percent difference between the hourly flow rates measured by the primary and redundant backup flow monitors even though both monitors had been passing their daily calibration error tests. In this instance, the primary flow monitor was being used for data reporting and was reading higher than the redundant backup monitor; therefore, it is unlikely that emissions were being under-reported. Had the primary monitor malfunctioned and the redundant backup been used, however, emissions would have been significantly under-reported (see Docket A–97–35, Item II–B–10).

Discussion of Proposed Changes

In view of the apparent shortcomings of the flow monitor daily calibration error test, EPA proposes to add a new flow monitor quality assurance test, the ''flow-to-load test,'' to part 75. The flow-to-load test, which would be performed quarterly, is described in proposed sections 7.7 of Appendix A and 2.2.5 of Appendix B. The proposed quarterly flow-to-load test would be required beginning in the first quarter of the year 2000.

The basic premise of the flow-to-load 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 (see Docket A–97–35, Items II–B–9, II–D–69). 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 (see Docket A–97–35, Items II–B–9, II–D–73, II–D–74, II–D–76, II–D–83, II–D–84). The flow-to-load ratio, or a normalized ratio, can thus serve as a quantitative indicator of flow monitor accuracy from quarter to quarter until the next RATA is performed.

The quarterly flow-to-load ratio test would be conducted as follows. The owner or operator would be required to determine R_{ref}, a reference value of the ratio of flow rate to unit load, each time that a successful normal-load flow RATA is performed. The value of R_{ref} would be reported in the electronic quarterly report required under § 75.64, along with the completion date of the associated RATA. If two load levels (e.g., mid and high) are designated as normal, the owner or operator would determine a separate R_{ref} value for each normal load level. The reference flow-to-load ratio would be calculated as follows:

$$R_{ref} = \frac{(Q_{ref})}{L_{avg}} \times 10^{-5}$$

In the equation above, R_{ref} is the reference value of the flow-to-load ratio from the most recent normal-load flow RATA; Q_{ref} is the average stack gas volumetric flow rate (in scfh) measured by the reference method during the normal-load RATA; and L_{avg} is the average unit load during the normal-load flow RATA. For a common stack, L_{avg} would 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 or ducts, Q_{ref} would be the sum of the total volumetric flowrates that discharge through all of the stacks (or ducts). The reference flow-to-load ratio would be rounded off to 2 decimal places.

As an alternative, the owner or operator could calculate a reference value of the gross heat rate (GHR) in lieu of R_{ref}. In order to exercise this option, quality assured diluent gas (CO_2 or O_2) data would have to be available for each hour of the most recent normal-load flow RATA. The reference value of the GHR would be determined as follows:

$$(GHR)_{ref} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000$$

In the equation above, $(GHR)_{ref}$ is the reference value of the gross heat rate at the time of the most recent normal-load flow RATA; $(\text{Heat Input})_{avg}$ is the arithmetic average hourly heat input during the normal-load flow RATA; and L_{avg} is the average unit load during the normal-load flow RATA. In calculating $(\text{Heat Input})_{avg}$, the average volumetric flow rate measured by the reference method during the RATA would be used in conjunction with the average diluent gas concentration measured during the RATA, substituting these values into the applicable heat input equation in Appendix F.

After establishing the reference flow-to-load or GHR value, an evaluation of the flow-to-load ratio or GHR would be required for each primary and redundant backup flow monitor on a quarterly basis. The owner or operator would be required to evaluate the flow-to-load ratio in each ''QA operating quarter'' (i.e., each quarter in which the unit or stack operates for at least 168 hours). At the end of each QA operating quarter, the owner or operator would calculate the flow-to-load ratio for every hour during the quarter in which: (1) 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 (2) a quality assured hourly average flow rate was obtained with a certified flow rate monitor. The owner or operator would have the option of using either bias-adjusted flow rates or unadjusted flow rates in the hourly flow-to-load ratios, provided that all of the ratios were calculated the same way. EPA had originally considered proposing that only unadjusted flow rates should be used to calculate the flow-to-load ratios. However, in response to comments received from CEMS Utility Workgroup members, the Agency is proposing to allow either unadjusted or bias-adjusted flow rates to be used, on the condition that the acceptance criteria for the flow-to-load test would be more stringent if bias-adjusted flow rates are used (see Docket A–97–35, Item II–D–82).

For a common stack, the ''load'' in each hourly flow-to-load ratio would 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 (or for a unit that monitors total flow rate in multiple ducts or breechings), the ''flow'' in the flow-to-load ratio would be the combined hourly volumetric flow rate through all of the stacks (or ducts). Each hourly flow-to-load ratio would be rounded off to 2 decimal places.

Alternatively, the owner or operator could calculate the hourly gross heat rate (GHR) values in lieu of the hourly flow-to-load ratios. However, an hourly GHR could only be determined for those hours within ±10.0 περψεντ οφ Λ_{avg} for which quality assured flow rate and diluent gas (CO_2 or O_2) concentration data are available from a certified CEMS or reference method. The owner or operator could use either bias-adjusted flow rates or unadjusted flow rates to determine the hourly GHR values.

The calculated hourly flow-to-load ratios (or gross heat rates) would be analyzed at the end of the quarter. A separate data analysis would be performed for each primary and each redundant backup flow rate monitor used to record and report data during the quarter. Each analysis would be based on a minimum of 168 hours of data. If two RATA load levels are designated as normal, the analysis would be performed at the higher load unless fewer than 168 data points were available at that load, in which case, the analysis would be performed at the lower load. If, for a particular flow monitor, fewer than 168 hourly flow-to-load ratios (or GHR values) were available at any normal load level, a flow-to-load (or GHR) evaluation would not be required for that monitor for that calendar quarter.

For each flow monitor, E_h, the difference (absolute value) between each hourly flow-to-load ratio and R_{ref}, would be expressed as a percentage of R_{ref} (or, if the GHR is used, the absolute difference between each hourly GHR value and $(GHR)_{ref}$ would be expressed as a percentage of $(GHR)_{ref}$). Then, E_f, the arithmetic average of all of the E_h values, would be calculated. Note that R_{ref} would always be based upon the most recent normal-load RATA, even if that RATA was performed in the calendar quarter being evaluated.

The owner or operator would be required to report the results of each quarterly flow-to-load (or GHR) evaluation in the electronic quarterly report required under § 75.64. The results of a quarterly flow-to-load (or GHR) evaluation would be considered acceptable, and no further action would be required if the average absolute percentage difference (E_f) did not exceed the following limits:

(i) 15.0 percent, if L_{avg} for the most recent normal load flow RATA is ≥ 50 megawatts (or ≥ 500 klb/hr of steam) and if unadjusted flow rates were used in the calculations;

(ii) 10.0 percent, if L_{avg} for the most recent normal load flow RATA is ≥ 50 megawatts (or ≥ 500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations;

(iii) 20.0 percent, if L_{avg} for the most recent normal load flow RATA is < 50 megawatts (or < 500 klb/hr of steam) and if unadjusted flow rates were used in the calculations;

(iv) 15.0 percent, if L_{avg} for the most recent normal load flow RATA is < 50 megawatts (or < 500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations.

If E_f exceeded the applicable limit, the owner or operator would have two available options: (1) perform a RATA, as described in proposed section 2.2.5.2 of Appendix B, unless a monitor malfunction is diagnosed and corrected, in which case an abbreviated flow-to-load test could be performed, in lieu of a RATA, in accordance with section 2.2.5.3 of Appendix B and discussed below; or (2) 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. If the owner or operator were to choose option (2), i.e., to recalculate E_f, only the flow rates for the following hours would be considered non-representative and could 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. The type of fuel would be different if the fuel is in a different state of matter (i.e., solid, liquid, or gas) or is a different classification of coal (e.g., bituminous versus sub-bituminous) than the fuel burned during the RATA;

(2) Any hour in which an 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) If a normal-load flow RATA was performed and passed during the quarter being analyzed, any hour prior to completion of that RATA; and

(5) If a problem with the accuracy of the flow monitor was discovered during the quarter and corrected, any hour prior to completion of the subsequent diagnostic test described in proposed section 2.2.5.3 of Appendix B, confirming that the corrective actions were successful.

After identifying and excluding any non-representative hourly data in accordance with (1) through (5) above, the owner or operator could analyze the remaining data a second time. At least 168 representative hourly ratios or GHR values at normal load would have to remain in order to perform the analysis; otherwise, the flow-to-load (or GHR) analysis would not be required for that monitor for that calendar quarter.

If, after re-analyzing the data, E_f is found to be within the applicable limit in (i), (ii), (iii), or (iv), above, then no further action would be required. However, if E_f is still outside the applicable limit, the monitor would be declared out-of-control as of the first hour of the quarter following the quarter in which the flow-to-load test was failed. The owner or operator would then perform a RATA as described in proposed section 2.2.5.2 of Appendix B, unless, as the result of an investigation, an instrument malfunction is discovered and corrected as described in proposed section 2.2.5.1 of Appendix B.

If a problem with the monitor is identified, all corrective actions (e.g., non-routine maintenance, repairs, major component replacements, re-linearization of the monitor, etc.) would have to be documented in the operation and maintenance records for the monitor. Data from the monitor would remain invalid until a ''probationary'' calibration error test of the monitor was passed following completion of all corrective actions, at which point data from the monitor would be assigned a ''conditionally valid'' status. The owner or operator would then perform an abbreviated flow-to-load test (found in proposed section 2.2.5.3 of Appendix B) to verify that the corrective actions were effective, unless the linearity of the flow monitor was affected by the corrective actions (e.g., by the changing of its polynomial coefficients). If the flow monitor linearity was affected, the owner or operator would no longer have the option of performing the abbreviated flow-to-load test in section 2.2.5.3 of Appendix B, but would instead be required to perform a 3-load recertification RATA in accordance with the recertification test period and data validation procedures of § 75.20(b)(3).

The abbreviated flow-to-load test in proposed section 2.2.5.3 of Appendix B is based on a recertification policy developed jointly by EPA, several utility representatives, and one flow monitor vendor (see Docket A–97–35, Items II–B–1, II–D–70, II–I–9, and II–I–16). Use of the abbreviated flow-to-load test would not be limited to situations in which a quarterly flow-to-load test has been failed. Rather, the test could 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) to demonstrate that the repair, replacement, or other corrective maintenance has not significantly affected the monitor's ability to accurately measure the stack gas volumetric flow rate. Data from the monitoring system would be considered invalid from the hour of commencement of the repair, replacement, or other corrective maintenance until the hour in which a "probationary" calibration error test is passed following completion of the repair, replacement, or other corrective maintenance and any associated adjustments to the monitor. The abbreviated flow-to-load test would have to 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 would be considered "conditionally valid" (as defined in § 72.2) beginning with the hour of the probationary calibration error test.

Following a flow-to-load test failure, the abbreviated flow-to-load test could be performed if the investigation into the cause of the test failure revealed a problem with the flow monitor and the problem was subsequently corrected without having to re-linearize the flow monitor. The test procedures would be as follows. The unit(s) would be operated 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, the load should be held constant to within ± 5.0 percent of the average load during the RATA, and the diluent gas (CO_2 or O_2) concentration should 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 possible, the same combination of units and load levels that were used during the RATA should be used. When the process parameters have been set, a minimum of 6 and a maximum of 12 consecutive hourly average flow rates would be recorded using the flow monitor(s) for which E_f was outside the applicable limit. For peaking units, a minimum of 3 and a maximum of 12 consecutive hourly average flow rates would be required. The corresponding hourly load values and, if applicable, the hourly diluent gas concentrations would also be recorded. The flow-to-load ratio or the GHR would be calculated for each hour in the test hour period using proposed Equation B–1 or B–1a in Appendix B. Then, E_h would be determined for each hourly flow-to-load ratio or GHR using proposed Equation B–2 in Appendix B. Finally, E_f , the arithmetic average of the E_h values, would be determined.

The results of the abbreviated flow-to-load test would be considered acceptable, and no further action would be required if the value of E_f did not exceed the applicable limit specified in proposed section 2.2.5.1 of Appendix B. All conditionally valid data recorded by the flow monitor would then 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 was found to be above the applicable limit, all conditionally valid data recorded by the flow monitor would 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 would be required, in accordance with proposed section 2.2.5.2 of Appendix B.

When a single-load RATA is performed because the owner or operator is unable to reconcile a quarterly flow-to-load test failure, either by excluding non-representative hours and recalculating E_f or by passing the abbreviated flow-to-load test after performing component replacement or other corrective maintenance on the flow monitor, then data from the monitor would remain invalid until the hour of successful completion of the single-load RATA.

Rationale

EPA believes that the proposed methodology for the quarterly flow-to-load test is fundamentally sound. It has been developed through a series of teleconferences and face-to-face meetings between EPA, members of the regulated community, and State and local agency personnel (see Docket A–97–35, Items II–D–77, II–D–80, II–D–81, II–D–82, II–D–85, II–E–23, II–E–24, II–E–25, II–E–26, and II–E–28). In addition, some provisions of the flow-to-load test were revised following pre-proposal comment. Specifically, the proposal reflects, in section 2.2.5.1 (b) of Appendix B to part 75, a commenter's request that if a quarterly flow-to-load test is failed and the monitor malfunction is discovered and corrected (without the need to relinearize the monitor), the correction could be verified using the abbreviated flow-to-load test in lieu of performing a single load RATA (see Docket A–97–35, Item II–D–42).

The proposed tolerance limits set forth in paragraphs (i), (ii), (iii), and (iv) of section 2.2.5 of Appendix B are believed to be both reasonable and achievable. When these tolerance limits are met, it provides a strong indication that the flow monitor is still accurate to within 10.0 percent of the reference method baseline established during the last normal-load flow RATA and would, therefore, appear to be in control with respect to the relative accuracy requirements of part 75. An extra tolerance of 5.0 percent has been incorporated into the limits to account for imprecision in the flow-to-load methodology. An extra 5.0 percent tolerance has also been added for smaller units (i.e., normal load less than 50 megawatts or 500 klb/hr of steam), because the flow-to-load ratio or GHR for such units is very sensitive to small variations in load (see Docket A–97–35, Item II–B–7).

To test the viability of the proposed tolerance limits, 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 (see Docket A–97–35, Items II–A–1, II–A–2, II–A–3). 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., baseloaded and peaking units, single fuel units, and units that burn multiple fuels). The flow-to-load test was applied to each unit or stack in the manner described above, except that *no* hours within ± 10.0 percent of L_{avg} were excluded from the data analysis. The data from these same units plus one additional multiple-stack unit were analyzed a second time, with each flow-to-load ratio being multiplied by the diluent gas concentration. This is similar, but not identical, to calculating the GHR. Once again, no hours within ± 10.0 percent of L_{avg} were excluded. In both analyses, *unadjusted* flow rates were used in the ratios. The results of the two 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 average value of E_f was 6.1 percent for the analysis without the diluent gas corrections and 6.4 percent for the analysis with the diluent gas corrections. A few units and stacks had a much lower E_f value when the diluent correction was applied, but in most cases, the diluent correction had relatively little effect. These results suggest that the flow-to-load test can provide EPA with the necessary assurance that flow monitors continue to generate accurate data from one RATA to the next. The results also indicate that the test should be relatively easy to pass if flow monitors are properly maintained and operated.

Because of the added quality assurance that would be provided by performing the flow-to-load or GHR test each quarter, EPA has reconsidered the scope of the other quality assurance tests for flow monitors. In today's proposed rule, the Agency is proposing to reduce the annual 3-load flow RATA requirement to a 2-load RATA and to reduce the frequency of 3-load RATAs to once every five years (and whenever a flow monitor is re-linearized). In addition, single-load flow RATA testing would be allowed in lieu of the annual 2-load test if the facility could demonstrate that a unit has operated at a single load level for at least 85.0 percent of the time in the four ''QA operating quarters'' prior to the scheduled RATA. (See Section N.2 of this preamble, below, for further discussion.) The Agency believes that, taken together, these proposed changes will reduce the cost and burden of quality assurance testing for flow monitors, while ensuring high data quality. The proposed reduction in the amount of required RATA testing is considered feasible because of the increased quality assurance provided by the quarterly flow-to-load test. EPA requests comment on the proposed revisions to flow monitor quality assurance requirements.

N. RATA and Bias Test Requirements

Background

Section 6.5 of Appendix A to the January 11, 1993 rule, as amended on May 17, 1995 and November 20, 1996, requires relative accuracy test audits of all primary and redundant backup SO_2, NO_X, CO_2, and flow monitoring systems to be performed during the initial certification of the CEMS. A RATA consists of a series of 9 or more simultaneous test runs, comparing measurements made by the continuous monitoring system against an EPA reference test method. The procedures for conducting RATAs are found in section 6.5 of Appendix A to part 75.

Following the initial certification of a CEMS, section 2.3 of Appendix B to part 75 requires that periodic RATAs of gas and flow monitors be performed to quality assure the data from the CEMS on an on-going basis. The frequency at which relative accuracy testing is required depends upon the results of the last RATA of a monitoring system. Part 75 currently requires RATAs to be performed semiannually, unless a monitoring system achieves a low enough relative accuracy to qualify for an annual test frequency. The Agency has always interpreted ''semiannually'' to mean that the deadline for the next RATA is the end of the second calendar quarter following the quarter in which a RATA is successfully completed, and ''annually'' to mean that the next RATA is due by the end of the fourth calendar quarter following the quarter in which a RATA is successfully completed. For monitors installed on peaking units and bypass stacks, however, the RATA deadlines are based on operating quarters, not calendar quarters. That is, the next RATA is due either at the end of the second or fourth unit operating quarter (for peaking units) or bypass stack operating quarter following the quarter in which a RATA is successfully completed.

For SO_2, NO_X, and CO_2 monitors, the RATAs are to be conducted while the unit is operating at normal load and while combusting the fuel that is normal for the unit. Flow monitor RATAs are to be conducted at three different loads, evenly spaced over the operating range of the unit. When a flow monitor is on a semiannual RATA frequency, a normal-load RATA rather than a 3-load RATA may be conducted to satisfy the semiannual test requirement, but a 3-load RATA is still required annually. Note that for flow monitors installed on peaking units and bypass stacks, 3-level flow RATAs are not required; RATAs are performed only at the normal load.

For SO_2, NO_X, and flow monitoring systems, section 7.6 of Appendix A requires that each time a RATA is successfully completed, a bias test be performed to determine if the system has a low measurement bias. If a monitoring system fails the bias test, a ''bias adjustment factor'' (BAF) must be applied to all subsequent emission data reported from that monitoring system. For 3-load flow RATAs, the bias test is done at the normal load. If a flow monitor fails the normal-load bias test, then a BAF must be calculated at each of the three load levels, and the highest of the three BAFs is applied to all flow data reported from the monitor.

When a RATA is due, section 2.3.1 in Appendix B of the rule allows the owner or operator two attempts to achieve an annual RATA frequency and/or a favorable BAF. If a second attempt is made, the RATA frequency and BAF obtained in the second RATA supersede the results of the first RATA. Once the RATA frequency has been established as semiannual or annual, section 2.3.1 of Appendix B specifies that (to the extent practicable) the next RATA of the CEMS may not be done until at least four months have elapsed.

Finally, § 75.21(a)(6) of the November 20, 1996 rule provides an exemption from the RATA requirements of part 75 for SO_2 monitors installed on units that burn only natural gas or fuel with a sulfur content no greater than natural gas. For units that burn both gas and higher-sulfur fuel, such as oil, as primary or backup fuels, § 75.21(a)(5) requires that the RATA of the SO_2 monitor be done when the higher-sulfur fuel is burned. Section 75.21(a)(7) further states that calendar quarters in which only fuel with a sulfur content no greater than natural gas is burned are to be excluded in determining the deadline for the next SO_2 monitor RATA.

Two utility groups, UARG and the Class of '85, have requested that EPA consider revising the RATA requirements of part 75 to make them more flexible, easier with which to comply, and less costly. Some of the possible changes suggested by these groups are as follows: (1) reduce the frequency of required RATAs; (2) determine RATA deadlines based on the amount of unit operation since the last RATA, rather than the number of calendar quarters that have elapsed; (3) remove the requirement to achieve a more stringent relative accuracy standard in order to obtain an annual RATA frequency; (4) except for initial certification, allow flow RATAs to be done at a single load; (5) allow single-point sampling during gas RATAs; and (6) allow a grace period in which to complete a RATA whenever a deadline is not met (see Docket A–97–35, items II–D–20, II–D–30, II–D–65, II–E–13, II–E–14).

Discussion of Proposed Changes

EPA is proposing revisions to the RATA requirements of part 75 based upon experience gained through implementation of the rule and in light of the recommendations made by the utility groups. Today's rulemaking sets forth the proposed changes, which are intended to make the RATA requirements less burdensome without sacrificing data quality.

1. RATA Frequency

EPA does not propose to revise the basic semiannual and annual RATA requirements of part 75 or the incentive system by which to obtain an annual RATA frequency (i.e., to obtain the reduced frequency, a better percentage relative accuracy is required). Instead, the Agency proposes to re-define the terms ''semiannual RATA frequency'' and ''annual RATA frequency,'' and to change the method by which RATA deadlines are determined.

Today's rule proposes to amend section 2.3 of Appendix B so that the deadline for the next RATA is determined on the basis of ''quality assurance operating quarters,'' rather than calendar quarters. This change would apply, with few exceptions, to all primary and redundant backup monitoring systems, including monitors installed on peaking units and bypass stacks. A ''QA operating quarter'' would be defined as a calendar quarter in which a unit operates for at least 168 hours or, for common-stacks and bypass stacks, a quarter in which flue gases discharge through the stack for at least 168 hours.

Any calendar quarter that does not qualify as a QA operating quarter would be excluded in determining the deadline for the next RATA. EPA therefore proposes to re-define the term ''semiannual RATA frequency'' to mean that the next RATA is due at the end of the second QA operating quarter following the quarter in which a RATA is successfully completed. Similarly, ''annual RATA frequency'' would mean that the next RATA is due at the end of the fourth QA operating quarter following the quarter in which a RATA is successfully completed.

The QA operating quarter methodology has been proposed principally for the benefit of cycling and peaking units to make the part 75 RATA requirements easier to meet. The proposed methodology will not greatly affect base-loaded units, since they seldom operate for less than 168 hours in a quarter. For base-loaded units, the QA operating quarter method is, in most instances, equivalent to the familiar calendar quarter scheme for determining RATA deadlines. Note, however, that on occasion a base-loaded unit may obtain an extended RATA deadline by the QA operating quarter methodology, e.g., when the unit goes into an extended outage (planned or forced) and experiences one or more quarters in which the unit operates for less than 168 hours.

Although the QA operating quarter method allows RATA deadlines to be extended by the exclusion of quarters in which the unit(s) operate for less than 168 hours, such exclusion of calendar quarters is not without limit. Section 2.3.1.1 of Appendix B proposes to allow a maximum of eight consecutive calendar quarters to elapse following the quarter in which the last RATA was performed. A RATA would either have to be performed by the end of the eighth consecutive elapsed calendar quarter since the last RATA or within a 720 unit operating hour ''grace period'' following the end of the eighth consecutive elapsed quarter. Failure to complete a RATA within the grace period would cause data from the monitoring system to become invalid from the hour of expiration of the grace period until the hour of completion of a successful RATA.

Although the proposed QA operating quarter methodology would serve as the basis for determining the RATA deadline for most routine quality assurance RATAs, there are five notable instances in the current rule or in today's proposal where the RATA deadline is either not determined solely on that basis or is determined entirely on another basis. The first instance is for a unit that burns both natural gas (or fuel with equivalent total sulfur content) and other higher-sulfur fuels as primary or backup fuels and that uses an SO_2 monitor to account for SO_2 mass emissions. Section 75.21(a)(7) of the current part 75 (redesignated as § 75.21(a)(9) in today's proposal) specifies that irrespective of the number of hours of unit operation in the quarter, any calendar quarter in which natural gas (or fuel with a total sulfur content no greater than the total sulfur content of natural gas) is the only fuel combusted in the unit (i.e., a ''gas-only'' quarter) is to be excluded in determining the deadline for the next RATA of the SO_2 monitoring system. Section 75.21(a)(5) of the current rule further states that for such units, the RATA of an SO_2 monitoring system is to be performed only when the higher-sulfur fuel is being combusted. Second, as discussed in section III.N.6 of this preamble, § 75.21(a)(7) of today's proposed rule would conditionally exempt from SO_2 RATA requirements any unit certified by the designated representative to burn fuel(s) with a sulfur content greater than natural gas only as emergency backup fuel or for short-term testing, provided that the annual usage of the higher-sulfur fuel(s) is kept below 480 hours. However if, during any quarter, the annual usage of the higher-sulfur fuel exceeded 480 hours, an SO_2 RATA would be required either in that quarter or during a subsequent grace period. Thus, for RATAs of SO_2 monitoring systems, it is evident that the number of unit operating hours in a calendar quarter is not the only consideration that determines the deadline for the next RATA; the total sulfur content of the fuel being combusted must also be considered. Third, as discussed in section III.O.6 of this preamble, for certain non-redundant backup monitoring systems, § 75.20(d) of today's proposal would require a periodic RATA every eight *calendar* quarters (rather than QA operating quarters). Fourth, as discussed in section III.N.2 of this preamble, under section 2.3.1.3 of Appendix B in today's proposal, 3-level flow RATAs would have to be performed once in every period of five consecutive *calendar* years (e.g., prior to permit renewal) and whenever a flow monitor is re-linearized. Fifth, as discussed in section III.O.4 of this preamble, for recertification RATAs, which are not regularly scheduled tests, but are done on an ''as-required'' basis, § 75.20(b)(3) of today's proposal specifies that the deadline for completing such RATAs would be 720 unit operating hours after the start of the recertification test period.

2. RATA Load Levels

Today's proposed rule would more clearly define the load levels at which RATAs are done in order to provide greater consistency in the way that RATAs are performed. The current provisions of part 75 are neither sufficiently standardized nor clear in defining the appropriate RATA load levels, particularly for flow RATAs. For example, section 6.5.2 of Appendix A specifies 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. Also, there is no minimum required load separation between the audit points at adjacent load levels. If adjacent audit points are too close together, a 3-level flow evaluation loses its significance. Finally, while the current rule requires gas and flow RATAs to be conducted at normal load, no definition of normal load is provided. It could be inferred from the current section 6.5.2 of Appendix A that the ''mid'' load level is considered normal because it requires the 3-load RATA to be done at a frequently used low load, a frequently used high operating load, and a normal load. However, experience in implementing the program has shown that for many units, the high load level is considered normal by the facility. For a few units, low load is considered normal, and for still others, the normal load can depend upon the time of day or the season of the year.

Proposed section 6.5.2.1 of Appendix A would therefore require the owner or operator first to define the ''range of operation'' for each unit or common stack equipped with hardware CEMS. The range of operation would extend from the minimum safe, stable load to the ''maximum sustainable load,'' which is the higher of: (a) the nameplate capacity of the unit (less any physical or regulatory deratings), or (b) the highest sustainable load, based on at least four quarters of representative historical data. For a common stack, the lower boundary of the range of operation would be the lowest minimum safe, stable load for any of the individual units using the stack. The upper boundary of the range would be obtained by adding together the maximum sustainable loads of all units using the stack, or if that combined load is unattainable in practice, by using the highest sustainable combined load based on at least four quarters of representative historical data. Three load levels would then be defined in terms of the range of operation. The ''low'' level would be the lower 30.0 percent of the range; the ''mid'' level would be the central portion (30.0 percent to 60.0 percent) of the range; and the ''high'' level would be 60.0 percent to 100.0 percent of the range. Proposed section 6.5.2 of Appendix A would specify that for multi-level flow RATAs, the audit points at adjacent load levels (e.g., low and mid, or mid and high) must be separated by no less than 25.0 percent of the range of operation. The owner or operator would be required to report the upper and lower boundaries of the range of operation in the electronic quarterly report required under § 75.64.

Section 6.5.2.1 of Appendix A in today's proposal would further require the owner or operator to determine, for each unit or common stack on which CEMs are installed (except for peaking units), the two load levels (low, mid, or high) that are the most frequently used. The two-fold purpose of this determination, which would be required, at a minimum, annually (just prior to the annual quality assurance RATAs and in the same calendar quarter as the RATAs), would be to identify the normal load level(s) and to identify the two load levels that are the most appropriate for annual 2-level flow monitor audits and for flow monitor bias adjustment factor calculations. To make the determination, the owner or operator would construct an historical load frequency distribution (e.g., histogram), depicting the relative number of operating hours at each of the three load levels, low, mid, and high. The frequency distribution would be based upon all available data from the four most recent QA operating quarters, as defined in proposed section 2.3.1.1 of Appendix B. The load frequency distribution would be used to determine the percentage of the time (to the nearest 0.1 percent) that each load level (low, mid, and high) has been used in recent history and thereby to identify the two most frequently used load levels. A summary of the data used for these determinations would be maintained on-site in a format suitable for inspection, and the results of the determinations would be included in the electronic quarterly report under § 75.64. The proposed revisions discussed in this paragraph would become effective as of January 1, 2000.

The owner or operator would be required under proposed section 6.5.2.1 of Appendix A to designate the most frequently used load level (low, mid, or high) as the normal load level for each unit or common stack (except for peaking units). The owner or operator would also have the option of designating the second most frequently used load level as an additional normal load level. Today's proposal would, therefore, not limit normal load to a single load level. This way of defining normal load is particularly appropriate for units that operate on a diurnal cycle and units that operate at distinctly different load levels during different seasons of the year due to ambient conditions, electrical demand, etc. EPA believes that the added flexibility in the definition of normal load (i.e., not confining it to a single load level) will allow the normal-load RATA requirements of part 75 to be more easily met. The owner or operator would be required to identify the selected normal load level(s) in the electronic quarterly report required under § 75.64. For peaking units, the entire range of operation would, for simplicity, be considered normal.

Revisions to section 2.3.1.3 of Appendix B are proposed in today's rule, requiring the routine quality assurance RATAs of flow monitors to be done as follows. For flow monitors installed on peaking units and bypass stacks, no changes are proposed; the requirement to perform only single-load flow RATAs at normal load would be retained. For all other flow monitors, the routine semiannual and annual RATAs would be done at 2 loads (i.e., the two most frequently used load levels, as identified in section 6.5.2.1 of Appendix A), with two exceptions: (1) the 2-load flow RATA could be performed alternately with a single-load flow RATA at the most frequently used (normal) load level, if the flow monitor is on a semiannual RATA frequency; and (2) a single-load flow RATA at the most frequently used load level could be performed in lieu of the 2-load RATA if, for the four QA operating quarters prior to the quarter in which the RATA is conducted, the historical load frequency distribution constructed under section 6.5.2.1 of Appendix A shows that the unit has operated at the most frequently used load level for ≥ 85.0 percent of the time. For all units, the requirement to perform periodic 3-load flow RATAs would be retained, but the frequency would be changed from annual to once every five calendar years. A 3-load RATA would also be required whenever a flow monitor is re-linearized (i.e., when its polynomial coefficients are changed). EPA is proposing to reduce the required frequency of 3-load RATAs and to allow limited use of single-load flow RATA testing principally because of the added assurance of data quality that will be provided by the proposed quarterly flow-to-load test.

3. Flow Monitor Bias Adjustment Factors

Today's rulemaking proposes to change the method of determining the bias adjustment factor for multiple-load flow RATAs. For 2-load RATAs (which would be done at the two most frequently used load levels as identified in proposed section 6.5.2.1 of Appendix A), the bias test would be done at the load level (or levels) designated as normal. If the monitor were to fail the bias test at any load level designated as normal, a bias adjustment factor (BAF) would be calculated at both load levels, and the higher of the two BAFs would then be applied to the subsequent flow data. For 3-load RATAs, the bias test would be required at each load level designated as normal under proposed section 6.5.2.1 of Appendix A. If the bias test were failed at any load level designated as normal, BAFs would be calculated only at the two most frequently used load levels (not all three levels), and the higher of the two BAFs would be applied to subsequent flow data. Thus, for all multiple-load flow RATAs, the appropriate BAF would be determined in the same way. For 3-load RATAs, this methodology for determining the BAF when the normal-load bias test is failed differs from the current rule, which requires the highest BAF from any of the three levels to be applied to subsequent data. Experience gained in the first few years of program implementation has shown that in many instances, the highest BAF has been from a load level that is seldom used (generally the low load level), which can result in an unrepresentatively high BAF being applied to the normal-load flow rate data.

4. Number of RATA Attempts

Section 2.3.1.4 of Appendix B to today's proposed rule would remove the restriction limiting to two the number of RATA attempts that may be done to achieve an annual RATA frequency. In addition, the requirement that successive RATAs be conducted no less than 4 months apart would be removed from section 2.3.1 of Appendix B. The proposed rule would conditionally allow the owner or operator to perform as many RATAs as are necessary to achieve a better relative accuracy percentage or a more favorable bias adjustment factor, the condition being that the data validation procedures for RATAs in proposed section 2.3.2 of Appendix B would have to be followed (these procedures are discussed in detail in Section II.O of this preamble, ''CEM Data Validation''). The Agency believes that this extra flexibility will provide an incentive for owners or operators to optimize CEMS performance and to eliminate bias from their monitoring systems and to reduce the frequency of the required RATAs.

5. Concurrent SO_2 and Flow RATAs

Today's proposed rulemaking would delete the requirement for concurrent SO_2 and flow RATA testing from § 6.5 of Appendix A. This requirement was included in the January 11, 1993 rule in order to generate a data base from which EPA could determine the appropriateness of setting a combined flow rate-SO_2 system relative accuracy specification. Section 3.3.5 of Appendix A was reserved for this future standard, which, if promulgated, would have become effective on January 1, 2000. After three years of program implementation, data collection, and evaluation, however, the Agency believes it is not appropriate or necessary to propose a combined flow rate-SO_2 system relative accuracy standard. Instead, EPA believes it would be more appropriate to retain the individual relative accuracy specifications for the SO_2 and flow monitors. Because the historical relative accuracy percentages of the individual component monitors have proven to be so low (i.e., average relative accuracy less than 5.0 percent for the period from the first quarter of 1995 through the second quarter of 1996), the Agency believes that it is not necessary to promulgate the combined standard (see Docket A–97–35, Item II–I–27). Data analysis from an EPA study (see Docket A–97–35, Item II–I–14) indicates that quality assuring the individual component monitors to 7.5 percent relative accuracy (the RA value needed to qualify for an annual RATA frequency) effectively ensures that a combined flow rate-SO_2 standard of 10.0 to 15.0 percent relative accuracy will be consistently achieved. That same study also indicates that meeting a combined flow rate-SO_2 standard of 10.0 percent does not necessarily ensure that the individual component monitor relative accuracies will be ≤ 10.0 percent. In view of this and given that flow monitors are also used to calculate heat input and CO_2 mass emissions, the Agency believes it is appropriate to maintain individual relative accuracy standards for the flow monitor and SO_2 monitor. EPA solicits comment on its proposed treatment of this issue.

6. SO_2 RATA Exemptions and Reduced Requirements

Today's proposed rulemaking would clarify the RATA requirements for units that burn principally natural gas and other very low-sulfur fuels. In § 75.21(a)(6) of the November 20, 1996 rule, an exemption from SO_2 RATA requirements was provided for units that have SO_2 monitors and exclusively burn natural gas (or fuels with a sulfur content no greater than natural gas). Today's proposed rule would clarify this exemption from SO_2 RATAs by interpreting the term ''fuel with a total sulfur content no greater than the total sulfur content of natural gas'' to mean any type of fuel that has a total sulfur content of less than or equal to 0.05 percent sulfur by weight. The rationale for this is as follows. In order to meet the definition of natural gas in § 72.2, the total sulfur content of the gas cannot exceed 20 grains/100 scf. When this sulfur content is converted to a weight percentage, it comes out slightly higher than 0.05 percent sulfur by weight (see Docket A–97–35, Item II–B–14). Consequently, for a unit that has an SO_2 monitor and for which the designated representative certifies that the unit burns only fuels (whether solid, liquid, or gaseous) with a total sulfur content of > 0.05 percent sulfur by weight, the SO_2 monitor would be exempted from the part 75 RATA requirements. The Agency takes comment on this approach and on whether 0.05 percent sulfur by weight is an appropriate applicability threshold for fuels other than natural gas.

Finally, § 75.21(a)(7) of today's rule proposes reduced RATA requirements for units with SO_2 monitors for which the designated representative certifies that the units burn fuel(s) with a total sulfur content greater than the total sulfur content of natural gas (e.g., distillate oil) only as emergency backup fuel(s) and/or for short-term testing. For such units, RATA testing of the SO_2 monitor would only be required if fuel with a total sulfur content greater than the total sulfur content of natural gas (i.e., > 0.05 percent sulfur by weight) is combusted for more than 480 hours in a calendar year. If the higher-sulfur fuel usage were to exceed 480 hours in a particular year, then an SO_2 RATA, conducted while burning the higher-sulfur fuel, would be required either by the end of the quarter in which the exceedance occurred or within a 720 unit operating hour grace period following that calendar quarter. In this instance, if the grace period were used, proposed section 2.3.3 in Appendix B would specify that it would begin with the first unit operating hour in which the higher-sulfur fuel is combusted in the unit, following the calendar quarter in which the annual usage of the higher-sulfur fuel exceeded 480 hours. The 480-hour criterion for maintaining an SO_2 RATA exemption is consistent with many state and local air permits which contain a similar exemption from particulate emission testing for gas-fired units that burn oil for only 400 to 500 hours per year (see Docket A–97–35, Item II–E–23). EPA believes that these provisions would effectively eliminate the need to start up a unit and/or to burn an infrequently used, uneconomical, and higher-emitting fuel solely for the purpose of performing a RATA of the SO_2 monitor.

7. QA Provisions for SO_2 Monitors, for Natural Gas Firing or Equivalent

In § 75.11(e) of the November 20, 1996 revisions to part 75, three SO_2 compliance options were promulgated for units with SO_2 CEMS during hours in which only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) is burned. One of the compliance options was to allow the use of an SO_2 monitoring system, subject to certain restrictions and quality assurance provisions. The restrictions and QA provisions, which are found at §§ 75.11(e)(3)(i) through (iv), are as follows: (i) a calibration gas with a concentration of 0.0 percent of span must be used for daily calibration error tests of the CEMS; (ii) the response of the monitoring system to the 0.0 percent calibration gas must be adjusted to read exactly 0.0 ppm each time that a daily calibration error test is passed; (iii) any hourly average of less than 2.0 ppm recorded by the SO_2 monitor while fuel is being combusted in the unit(s) (including zero and negative averages) must be reported as a default value of 2.0 ppm; and (iv) if a unit combusts only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) and never combusts any other type of fuel, the SO_2 monitor span must be set to a value not exceeding 200.0 ppm. Compliance with conditions (i) through (iv) is required by January 1, 1999, except that conditions (i) and (ii) are always optional for units that combust natural gas only during unit startup.

The provisions in §§ 75.11(e)(3)(i) through (iv), as presently codified, apply only to the combustion of *gaseous* fuel with a total sulfur content no greater than the total sulfur content of natural gas. However, as noted above (under ''SO_2 RATA Exemptions and Reduced Requirements''), today's proposed rulemaking would add an interpretation of the term ''fuel with a total sulfur content no greater than the total sulfur content of natural gas'' to § 75.21(a)(6). The term would include *any* fuel (whether solid, liquid, or gaseous) with a total sulfur content of $\leq$ 0.05 percent by weight. EPA believes that it is appropriate to apply the quality assurance and reporting provisions in §§ 75.11(e)(3)(i) through (iv) to the combustion of *all* fuels with a total sulfur content $\leq$ 0.05 percent by weight. Therefore, in today's proposed rule, a new section, § 75.21(a)(8) would be added, extending the QA provisions of §§ 75.11(e)(3)(i) through (iv) to the combustion of all types of fuels with a total sulfur content no greater than the total sulfur content of natural gas. The new requirements would become effective on January 1, 2000.

Note that EPA has reconsidered one of the four QA provisions for the use of an SO_2 monitor during natural gas (or fuel with equivalent total sulfur content) combustion in §§ 75.11(e)(3)(i) through (iv). Specifically, the Agency believes that § 75.11(e)(3)(ii), which requires a daily adjustment of the monitor's calibration to read *exactly* 0.0 ppm, may be too stringent because in practice it can be very difficult to attain a reading of exactly 0.0 ppm with a zero-level calibration gas, particularly when manual calibration adjustments are made. Therefore, today's rulemaking proposes to revise § 75.11(e)(3)(ii) as follows. Rather than requiring a daily adjustment of the SO_2 monitor's calibration, an adjustment would only be required when the ''as-found'' response of the monitor to the zero gas during a daily calibration error test exceeded the performance specification of the instrument (i.e., ±2.5 percent of span). And instead of requiring the calibration to be adjusted to exactly 0.0 ppm, the procedures for routine calibration adjustments in proposed section 2.1.3 of Appendix B would be followed, to bring the ''as-left'' response of the instrument (i.e., the response during the additional calibration error test required by proposed section 2.1.3 of Appendix B) ''as close as practicable'' to the true value of the zero gas (0.0 ppm).

The Agency solicits comment on the proposed approach for QA provisions for SO_2 CEMS for gas-firing or equivalent.

8. General RATA Test Procedures

Under today's proposal, sections 6.5, 6.5.1, and 6.5.2 of Appendix A, which describe the general requirements for RATAs, would be extensively revised. Some of the proposed changes are simply structural, but others are substantive. For instance, as previously discussed above under ''Concurrent SO_2 and Flow RATAs,'' the requirement to perform concurrent SO_2 and flow RATAs would be deleted from the regulation. Further, section 6.5 would now recognize that more than one type of fuel and more than one monitor range may be considered normal for a particular unit. Also, the requirement to complete each RATA within 7 consecutive calendar days would be modified to require that the RATA be completed within 168 unit operating hours (for single-load flow RATAs and, to the extent practicable, for 2-load and 3-load flow RATAs). However, for the multiple-load flow RATAs, up to 720 unit operating hours would be allowed, if necessary, to complete the testing. This is consistent with Agency guidance published in March, 1995, Policy Question 8.15 of the Acid Rain Policy Manual, which discusses allowing up to 30 calendar days to complete all three levels of a 3-load flow RATA (see Docket A–97–35, Item II–I–9). Even though the policy says the RATAs at the individual load levels should be completed within 7 days, thirty days are acceptable to complete the 3-load RATA in order to account for the possibility that the unit might shut down in between levels of the RATA or that certain load levels may be difficult to attain and to hold. Today's proposal would allow 720 unit operating hours (irrespective of the number of calendar days) to complete a multiple-load flow RATA. EPA believes that this proposed requirement provides greater flexibility than currently allowed.

Sections 6.5.1 and 6.5.2 of Appendix A would be re-titled ''Gas Monitoring Systems (Special Considerations)'' and ''Flow Monitor RATAs (Special Considerations),'' respectively. Proposed section 6.5.1 contains a recommendation that, for initial monitor certifications, the RATA not be commenced until all of the other certification tests have been completed. Section 6.5.2 would be amended, as previously discussed under ''Flow RATA Load Levels.'' The definition of normal load would be revised and the number of loads and the load levels at which flow RATAs are to be performed would be more clearly defined.

Today's rule proposes changes to section 6.5.6 of Appendix A, which pertains to RATA traverse point selection. Proposed section 6.5.6 would allow the following alternative reference method measurement point locations. For *all* moisture determinations, a single reference method point, located at least 1.0 meter from the stack wall, could be used. For gas RATAs, the owner or operator would have four options: (1) at *any* location (including locations where stratification is expected), a minimum of six traverse points along a diameter, located in accordance with Method 1 in Appendix A to part 60, could be used; (2) at locations where stratification is not expected and section 3.2 of Performance Specification No. 2 (''PS No. 2'') in Appendix B to part 60 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 could use an alternative 3-point measurement line, locating the three points 4.4 percent, 14.6 percent and 29.6 percent of the way across the stack, in accordance with Method 1 in Appendix A to part 60; (3) at locations where stratification is expected (i.e., after 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 option (2) above) could be used in lieu of the ''long'' measurement line prescribed in section 3.2 of PS No. 2, provided that a stratification test is performed prior to each RATA at the location and certain acceptance criteria are met; and (4) 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. EPA's Office of Air Quality Planning and Standards (OAQPS) has endorsed the use of the Method 1 traverse points as an alternative to the points prescribed by PS No. 2 (see Docket A–97–35, Item II–C–22).

Regarding option (3) above, one utility and one stack testing firm have requested that EPA allow the short measurement line to be used at scrubbed unit stacks, citing logistical difficulties and safety concerns associated with using the long measurement line prescribed by PS No. 2 for sampling locations following wet scrubbers (see Docket A–97–35, Items II–D–66, II–D–78). Both parties appeared willing to perform stratification testing to demonstrate that the gas streams are not significantly stratified. EPA responded to these requests by issuing policy guidance which discusses allowing the short measurement line to be used for scrubbed units, provided that stratification test results show the stratification at the sampling location to be minimal (see Docket A–97–35, Item II–I–9, Policy Manual, Question 8.25). Regarding single-point RATA testing (option (4), above), which utility groups asked EPA to consider, today's proposed rule would allow it on the condition that a stratification test at the sampling location demonstrates stratification to be essentially absent.

Sections 6.5.6.1 and 6.5.6.2 of Appendix A in today's proposed rule provide two stratification test protocols which may be used to demonstrate that a sampling location qualifies for the alternative RM measurement point locations allowed under proposed section 6.5.6 (i.e., options (3) and (4), above). The first stratification test protocol, in proposed section 6.5.6.1, is based upon technical guidance issued by OAQPS (see Docket A–97–35, Item II–I–3) and would consist of measuring the SO_2, NO_X, and diluent gas concentrations at a minimum of 12 traverse points, located in accordance with Method 1 in Appendix A to part 60. The gas concentration measurements would be made using Reference Methods 6C, 7E, and 3A in Appendix A to part 60. The average NO_X, SO_2, and CO_2 (or O_2) concentration at each of the individual traverse points would be determined, and the arithmetic average NO_X, SO_2, and CO_2 (or O_2) concentrations for all traverse points calculated. This 12-point test would have to be passed one time at the sampling location under consideration. Once the 12-point test has been passed at the candidate sampling location, the second (abbreviated) stratification test protocol, in proposed section 6.5.6.2, could be done prior to subsequent RATAs at the location in lieu of the 12-point test. The abbreviated test would be done either at 3 points (located in accordance with the long measurement line in PS No. 2) or at 6 points along a diameter (located according to EPA Method 1 in Appendix A to part 60).

The acceptance criteria for the stratification test results are given in proposed section 6.5.6.3 of Appendix A. For each pollutant or diluent gas, the short 3-point reference method measurement line specified in section 3.2 of PS No. 2 (or the alternative 3-point line described in proposed section 6.5.6 of Appendix A) could be used for that pollutant or diluent gas in lieu of the long measurement line in section 3.2 of PS No. 2, if the concentration at each individual traverse point differed by no more than ±10.0 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 ±5.0 ppm or 0.5 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points. Further, for each pollutant or diluent gas, a single reference method measurement point located at least 1.0 meter from the stack wall could be used for that pollutant or diluent gas, 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. Finally, proposed section 6.5.6.3 would require the owner or operator to keep the results of all stratification tests on-site, suitable for inspection, as part of the supplementary RATA records required under § 75.56(a)(7) and § 75.59(a)(7).

Today's rule also proposes to clarify the sampling strategy for RATAs in section 6.5.7 of Appendix A. The proposed revisions make it clear that for gas monitor RATAs, the minimum time per run is 21 minutes, and all of the necessary data for each run (i.e., pollutant concentration measurements and, if applicable, diluent concentration data and moisture measurements) would have to be collected, to the extent practicable, within a 60-minute period. The proposed revisions would also require the pollutant and diluent concentration measurements to be made simultaneously during RATAs of SO_2/diluent and NO_X/diluent monitoring systems. For flow monitor RATAs, the minimum time per run would be 5 minutes. A requirement to properly account for flow pulsations (e.g., by sight-weighted averaging) at each velocity traverse point would be added, as well as a clear statement that successive flow RATA runs may be done as rapidly as practicable, with no required waiting period between runs. Proposed section 6.5.7 of Appendix A states that a minimum of one set of auxiliary data (moisture and diluent gas measurements) would have to be collected for every three RATA runs or for every clock hour of a flow RATA (whichever is less restrictive). A related change to § 75.22(a)(4) is also proposed, which would allow the alternative moisture measurement techniques described in section 1.2 of Method 4 in Appendix A to part 60 to be used for stack gas molecular weight determinations.

9. Reference Method Testing Issues

Discussion of Proposed Changes

Currently, § 75.22 specifies several reference methods (Reference Methods 2, 2A, 2C, or 2D) as appropriate methods for determining volumetric flow under part 75. The Agency is currently conducting a study of the accuracy of Reference Method 2 to determine whether changes to Method 2 or the addition of other alternatives to the Method are appropriate. Thus, the Agency anticipates that, in the future, revisions to Method 2 in part 60 may create alternatives beyond the specific reference methods specified in § 75.22(a)(2). Therefore, in § 75.22(a)(2), EPA proposes to add: ''or its allowable alternatives, except for 2B and 2E'' to Method 2 to automatically incorporate into part 75 anticipated future revisions to the Method 2 requirements in Appendix A to part 60.

Section 75.22 specifies a number of instrumental reference methods from Appendix A to part 60 (Reference Methods 3A, 6C, 7E, and 20) as appropriate test methods for conducting CEMS performance tests under part 75. These methods require the use of calibration gases to calibrate the reference analyzers. Currently, however, part 60 does not require that EPA protocol gas be used when performing instrumental reference methods. The Agency believes that protocol gas should be used when performing instrumental reference methods in order to achieve accurate results. Therefore, proposed § 75.22(c)(1) would state that, for purposes of part 75, instrumental reference methods must be performed using calibration gases as defined in section 5 of Appendix A to part 75.

10. Alternative Relative Accuracy Specifications and Specifications for Low-Emitters

One utility group has suggested to EPA (see Docket A–97–35, Item II–E–13) that there is inconsistency and apparent inequity in the relative accuracy specifications for units that qualify as low emitters of NO_X and SO_2 (i.e., sources with average SO_2 concentrations of 250.0 ppm or less and/or average NO_X emission rates of 0.20 lb/mmBtu or less). Specifically, they have questioned the appropriateness of the alternative relative accuracy specifications used to determine the RATA frequency (i.e., semiannual or annual). Under section 3.3 of Appendix A and section 2.3.1 of Appendix B to the current part 75 rule, the RATA frequency for an SO_2 monitor installed on a low-emitting SO_2 source may be determined in either of two ways: by the normal relative accuracy specification (i.e. the RATA frequency is semiannual if the relative accuracy is > 7.5 percent but ≤ 10.0 percent, and annual if ≤ 7.5 percent relative accuracy is achieved), or by the alternative specification (i.e., the RATA frequency is semiannual if the reference method mean value and CEMS mean value differ by > 8.0 ppm but ≤ 15.0 ppm, and annual if the two mean values differ by ≤ 8.0 ppm). For low-emitting NO_X sources, the RATA frequency for the NO_X monitoring system is determined in the identical manner to SO_2 when the normal specification is applied. For the alternative specification, the NO_X RATA frequency is semiannual if the CEMS and reference method mean values differ by ≤ 0.01 lb/mmBtu but ≤ 0.02 lb/mmBtu, and annual if the mean values differ by > 0.01 lb/mmBtu. The 8.0 ppm value for SO_2 was originally determined based on the performance of a single set of monitors at a facility regulated under subpart Da of the NSPS in part 60. However, in the first few years of Acid Rain Program implementation, many part 75 utilities with wet scrubbers have found it difficult to consistently meet the 8.0 ppm criterion for obtaining an annual RATA frequency.

The utility group maintains that since, when the normal relative accuracy (RA) specification is applied, the criterion for obtaining an annual RATA frequency is to achieve a relative accuracy 25.0 percent below the RA specification in section 3.3 of Appendix A (i.e., 7.5 percent RA is 25.0 percent below the specification of 10.0 percent), the criterion for an annual RATA frequency should be essentially the same when the alternative specification is applied. Under the current rule, the alternative SO_2 specification requires that the mean CEMS and reference method values differ by no more than 8.0 ppm in order to obtain an annual RATA frequency. This is 47.0 percent below the 15.0 ppm alternative RA specification. Similarly for NO_X, the alternative NO_X specification for an annual RATA frequency requires the difference between the CEMS and reference method mean values to be ≤ 0.01 lb/mmBtu, or 50.0 percent below the 0.02 lb/mmBtu alternative RA specification.

EPA agrees that the alternate RA specifications for low emitters of SO_2 and NO_X appear to be somewhat inequitable, and today's rulemaking proposes changes to these specifications. In proposed section 2.3.1 of Appendix B, the alternative relative accuracy specification for low emitters of SO_2, (i.e., the difference between the reference method and CEMS mean values) that must be met by an SO_2 monitor in order to obtain an annual RATA frequency would be changed from 8.0 ppm to 12.0 ppm. For low emitters of NO_X, the alternative low emitter relative accuracy specification that must be met by a NO_X-diluent monitoring system in order to obtain an annual RATA frequency would be changed from 0.01 lb/mmBtu to 0.015 lb/mmBtu.

In today's rule, EPA is also proposing an alternative relative accuracy specification of 0.025 lb/mmBtu for SO_2-diluent monitoring systems to obtain an annual RATA frequency and an alternative relative accuracy specification of ±0.7 percent CO_2 or O_2, by which CO_2 and O_2 monitors could obtain an annual RATA frequency. During the investigation of the alternative RA specifications for the SO_2 and NO_X-diluent monitoring systems, the Agency noted that for SO_2-diluent systems, part 75 specifies only an alternative RA criterion of 0.030 lb/mmBtu for a semiannual RATA frequency, but fails to specify a corresponding alternative RA criterion for obtaining an annual RATA frequency. Similarly, for CO_2 and O_2 monitors, EPA noted that an alternative relative accuracy specification of ±1.0 percent CO_2 or O_2 (in terms of the mean difference between the reference method and CEM values during the RATA) is given for obtaining a semiannual RATA frequency, but no corresponding alternative criterion is given for obtaining an annual frequency.

EPA notes that in order to make the annual RATA frequency criteria for NO_X-diluent and SO_2-diluent monitoring systems more equitable, a third decimal place is required. However, §§ 75.54 and 75.55 currently require NO_X and SO_2 emission rates in lb/mmBtu to be reported only to 2 decimal places. Therefore, revisions are being proposed, see §§ 75.57(d)(6) and 75.58(a)(1)(iv), to require that, beginning on January 1, 2000, all NO_X emission rates in lb/mmBtu must be reported to three decimal places. Prior to January 1, 2000, the owner or operator would have the option of reporting NO_X emission rates to either two or three decimal places. Note that no corresponding change is being proposed for the reporting of SO_2 emission rates in lb/mmBtu, since such emission rates will only be reported to EPA by units that have installed Phase I Qualifying Technologies for a three-year period (1997–1999), and are not required to be reported thereafter. EPA solicits comments on the appropriateness of requiring *all* NO_X lb/mmBtu emission rates to be reported to three decimal places. The Agency favors this approach, particularly for quality assurance purposes, due to increased precision in the calculation of RATA results. The Agency notes that this proposed change would not affect the way in which compliance with the NO_X emission limits under part 76 is determined. Compliance with part 76 NO_X limits, in lb/mmBtu, would still be based on two decimal places.

All of the proposed revisions to the part 75 relative accuracy specifications in today's rulemaking are summarized in proposed Figure 2 of Appendix B.

11. *Bias Adjustment Factors for Low Emitters*

As discussed in the preceding section, sources that qualify as low emitters of SO_2 and/or NO_X have two ways to evaluate the relative accuracy of SO_2 and NO_X monitoring systems: (a) by the normal relative accuracy specification (i.e., 10.0 percent RA), and (b) by the alternative RA specification (i.e., the difference between the mean CEMS and reference method values is within ±15.0 ppm for SO_2 low emitters, or within ±0.02 lb/mmBtu for NO_X low emitters).

The normal RA is determined by a statistical analysis of the reference method and CEMS data from the RATA. Mathematically, the normal RA is the sum of the absolute values of the mean difference (d_{mean}) and the confidence coefficient (cc), expressed as a percentage of the mean reference method value $(RM)_{avg}$. The mean difference indicates how closely the CEMS measurements agree with the reference method and is generally the principal contributor to the percentage relative accuracy in the RA equation. The confidence coefficient (cc) is a statistical term related to the standard deviation and is an indicator of the amount of scatter in the data.

Section 7.6 of Appendix A requires a bias test of each SO_2 and NO_X monitoring system whenever a RATA of the CEMS is performed. If the mean difference is greater than the absolute value of the confidence coefficient, the CEMS measurements are systematically lower than the corresponding references method measurements, i.e., the monitoring system has a low bias. In such cases, sources are given two options. The first, preferred by EPA, is to locate and eliminate the source of the measurement bias in the instrument. The second option is to apply a bias adjustment factor (BAF). This alternative was developed in response to an industry request to provide an alternative for sources that choose not to expend the effort to locate and eliminate the technical problem causing the systematic measurement error. The BAF is equal to $1.000 + |d_{mean}| / (CEM)_{avg}$, where $(CEM)_{avg}$ is the mean value of the CEMS measurements from the RATA.

At least one utility has questioned whether it is appropriate for low emitters to calculate a BAF in the usual way when a CEMS fails a RATA by the normal RA specification, but passes by the alternative specification, because in such cases the BAF can become inordinately high, particularly at very low emission levels (see Docket A–97–35, Items II–D–62 and II–E–23). Since both the percent relative accuracy and the BAF are based upon the same statistical terms (d_{mean} and cc), the utility questions whether the standard calculation procedure for the BAF is adequate to determine a meaningful BAF for low emitters. Just as the value obtained from the standard relative accuracy equation tends to become large for low emitters, so, too, the BAF is seen as becoming inordinately large for low emitters which use the current BAF equation.

As this comment suggests, it is not uncommon for an SO_2 or NO_X CEMS installed on a low-emitting unit to fail a RATA by the normal specification of 10.0 percent RA and to pass the same RATA by the alternative RA specification. For instance, suppose that the mean RM and CEMS values during an SO_2 RATA of a low emitter are 51.0 ppm and 40.0 ppm, respectively, and that d_{mean} is 11.0 ppm and the confidence coefficient is 0.50. Suppose further that the bias test is failed. Then, the percent RA by the normal specification (i.e., $|d_{mean}| + |cc| / (RM)_{avg}$) would exceed 20.0 percent, indicating a failed RATA, but the alternative RA specification would indicate a pass (i.e., $(CEMS)_{avg}$ is within ±15.0 ppm of $(RM)_{avg}$). In this same illustration, the BAF would be 1 + 11 / 40 = 1.275.

In fact, if it is assumed that the difference between the CEMS and the reference method measurements does not decrease as emissions decline, then the lower the SO_2 or NO_X emissions, the more likely it is for the CEMS to fail the normal relative accuracy specification because the mean difference becomes a larger percentage of the average reference method value. It was precisely in response to such concerns that the alternative relative accuracy specifications were originally included in part 75.

Today's rule proposes to provide an option in the way the BAF is determined for low emitters of SO_2 and NO_X. Low emitters of SO_2 and NO_X would be given the choice of using either: (a) the normal BAF calculation procedure described above and found in Equation A–12, section 7.6.5 of Appendix A, or (b) an alternative default bias adjustment factor of 1.111.

The justification is as follows: for units that meet the normal relative accuracy standard of RA ≤ 10.0 percent, the theoretically maximum possible Bias Adjustment Factor is 1.111 (see Docket A–97–35, Item II–B–2). Therefore, low-emitting units meeting the alternative relative accuracy standards ($|d_{mean}| \leq 15.0$ ppm for SO_2 low emitters and $|d_{mean}| \leq 0.02$ lb/mmBtu for NO_X low emitters) should not have to apply a bias adjustment any higher than the maximum BAF value applicable to units meeting the normal relative accuracy standard. EPA solicits comment on allowing the alternative BAF of 1.111 for low-emitting units.

12. Clarification of Diluent Monitor Certification Requirements

Today's proposed rule would clarify the certification requirements for diluent gas (CO_2 and O_2) monitors, in response to comments received on the pre-proposal draft of the rule (see Docket A–97–35, Item II–D–52). Section 75.20(c)(1)(iii) of the current rule requires a RATA of each NO_X continuous monitoring system to be done for initial certification. Even though the NO_X system consists of two component monitors (NO_X concentration and diluent gas), the required RATA is done on a system basis in units of lb/mmBtu. Separate RATAs of the individual component monitors are not required, except when the diluent component monitor is also used as a CO_2 pollutant concentration monitor or to account for unit heat input, in which case § 75.20(c)(5)(iii) in the current rule requires a RATA of the diluent monitor. To be sure that this is clear, today's proposed rule would add a statement to § 75.20(c)(1)(iii), indicating that the RATA for the NO_X-diluent system shall be done on a system basis (i.e., individual component RATAs are unnecessary for certification of a NO_X-diluent system). Therefore, units that have installed NO_X monitoring systems, but that use Appendix D for SO_2 emission accounting and Appendix G for CO_2 accounting, would not be required to submit separate RATA results for the diluent monitor.

A second point of clarification would be added in proposed § 75.20(c)(3), which was previously designated as § 75.20(c)(4). The new section would make it clear that when a diluent monitor (O_2 or CO_2) is used both as a CO_2 pollutant concentration monitor and for heat input determinations, only one set of diluent monitor certification test results would have to be submitted under the component and system ID codes of the CO_2 monitoring system. This is appropriate because there is no such thing as a ''heat input monitoring system'' or an ''oxygen monitoring system'' under part 75.

13. Daily Calibration Requirements for Redundant Backup Monitors

Section 75.20(d)(1) of the current rule requires redundant backup (''hot-standby'') monitoring systems to be operated during all periods of unit operation and to meet all of the quality assurance requirements of Appendix B, including daily calibrations and interference checks, quarterly linearity checks and leak checks, and semiannual or annual RATAs. One commenter on a pre-proposal draft of today's proposed rule requested that EPA consider changing the daily calibration requirement for redundant backup monitors (see Docket A–97–35, Item II–D–35). The commenter recommended that the daily calibrations be made mandatory only for days on which the redundant backup monitoring system is actually used to report emission data to EPA. Daily calibrations would be optional on all other days. Fewer calibrations of redundant backup systems would considerably reduce calibration gas consumption. The commenter estimated that this change could result in an annual savings of more than $100,000 for his company. EPA agrees that the request is reasonable, provided that the redundant backup systems are kept on hot-standby and are calibrated prior to each use for reporting. The Agency therefore proposes to amend § 75.20(d)(1) accordingly.

14. Daily Performance Specification and Control Limits for Low-Span DP Flow Monitors

Section 3.1 of Appendix A of the current rule gives the calibration error performance specification for flow monitors. Section 2.1.4 of Appendix B gives the calibration error limits for daily operation of flow monitors. For initial certification, a flow monitor is required to meet a calibration error specification of ≤ 3.0 percent of the span value. For daily operation of the flow monitor, the calibration error must not exceed 6.0 percent of span. These specifications are both reasonable and achievable for the vast majority of flow monitors. However, when a differential pressure (DP) type flow monitor is used to measure stack gas flow rate in a stack that has low exit velocities, it can be very difficult for the monitor to pass its daily calibration error tests. This is because the daily calibration span value for a DP flow monitor is expressed in units of inches of water. For stack exit velocities less than 2000 feet per minute, the calibration span value will be a very small number (0.20 inches of water or less). When performing a daily calibration error test of a flow monitor with a span value of 0.20 inches of water, the test would be failed (i.e., the calibration error would exceed 6.0 percent of span) if the response of the monitor deviated from either the zero or high reference signal by 0.02 inches of water. For span values of 0.15 inches of water or less, the calibration error test would be failed if the monitor's response deviated from the reference signals by 0.01 inches of water. One utility with a DP type flow monitor with a span value less than 0.15 inches of water has indicated to EPA that it cannot pass daily calibrations unless the monitor responses exactly equal the reference signal values (see Docket A–97–35, Item II–E–30). Clearly, these daily calibration specifications are too stringent for low span DP-type flow monitors. In view of this, EPA is proposing alternative calibration error specifications for DP type flow monitors with low span values, with ''low'' span value meaning a span value of 0.20 inches of water or less. The alternative performance specification for initial certification, given in proposed section 3.1 of Appendix A, would be ± 0.01 inches of water, rather than ± 3.0 percent of span. The alternative specification for daily operation of the monitor, given in proposed section 2.1.4 of Appendix B, would be ± 0.02 inches of water, rather than ± 6.0 percent of span. Since the results of a calibration error test of a DP type flow monitor are reported to 2 decimal places, the performance specification of ± 0.01 inches of water, is the tightest specification that could be imposed, short of requiring the monitor to read exactly the reference value with zero tolerance (which is what the current specification of ± 3.0 percent of span essentially imposes on a DP flow monitor with very low span). The Agency solicits comment on this proposed approach and on the value of the alternate specification.

O. CEM Data Validation

Background

The current requirements of part 75 regarding CEM data validation are as follows. Section 75.10 specifies that a valid hourly average from a CEMS must be based on a minimum of four evenly spaced data points (i.e., one point in each 15-minute quadrant of the clock hour), except that two evenly spaced data points separated by at least 15 minutes are sufficient to validate an hourly average when daily calibration error tests and/or other required quality assurance activities are conducted during the hour. Data from a CEMS are considered to be quality assured, provided that the monitoring system has passed all of the initial certification tests required under § 75.20(c) and provided that the CEMS is not ''out-of-control,'' as a result of having failed any of the daily, quarterly, semiannual, and/or annual quality assurance tests required in sections 2.1 through 2.3 of Appendix B. Out-of-control periods extend from the hour of failure of a QA test until the hour of completion of a subsequent successful QA test of the same type. For instance, if a linearity check of a gas monitor is failed, the monitor is considered out-of-control from the hour of completion of the failed test until the hour of completion of a subsequent successful linearity test.

Finally, § 75.20(b)(3) specifies that when a change is made to a CEMS such that recertification of a monitor becomes necessary, data from the CEMS are invalid from the hour in which the change is made to the system until the hour of completion of all required recertification tests.

In the first three years of implementing part 75, EPA has received numerous requests from the utilities for guidance concerning CEM data validation. This has prompted the Agency to re-examine these provisions of the rule. From this re-examination, the Agency believes that the current data validation provisions of part 75 are neither sufficiently detailed nor flexible to address the complex realities of daily operation of utility boilers and continuous emission monitoring systems. Therefore, today's proposed rule would set forth more comprehensive data validation criteria.

Discussion of Proposed Changes

Today's proposed rule would set forth proposed guidelines for the validation of CEM data, attempting to take into account the realities associated with the operation and maintenance of electric utility steam generating units and continuous emission monitoring systems. The proposed guidelines would govern CEM data validation as it pertains to six principal areas: (1) calibration error tests and adjustment of gas and flow monitors; (2) linearity tests of gas monitors; (3) relative accuracy test audits of gas and flow monitoring systems; (4) recertifications of gas or flow monitors; (5) data from non-redundant backup monitoring systems; and (6) missed QA test deadlines. These proposed guidelines for data validation are discussed in detail below.

1. Recalibration and Adjustment of CEMS

Today's proposed rule would revise section 2.1.3 of Appendix B, the ''recalibration'' section. The May 17, 1995 rule recommends (but does not require) the calibration of a monitor to be adjusted whenever the daily calibration error exceeds the performance specification in Appendix A. For example, if the calibration error of a gas monitor exceeds 2.5 percent of span, but does not exceed the daily control limit of 5.0 percent of span, the monitor is considered to be out-of-adjustment but not out-of-control, and EPA recommends that calibration of the monitor be adjusted.

Today's proposal would re-title section 2.1.3 as ''Additional Calibration Error Tests and Calibration Adjustments.'' The recommendation to adjust the monitor when the calibration error exceeds the Appendix A performance specification would be retained, but definitions of ''routine calibration adjustments'' and ''non-routine calibration adjustments'' would be added. Routine calibration adjustments would be defined as adjustments made to a CEMS following a successful calibration error test. The purpose of these adjustments would be to bring the monitor readings as close as practicable to the tag values of the reference calibration gases or to the known values of the flow monitor reference signals. Non-routine calibration adjustments would be adjustments in either direction (toward or away from the reference value), but within the performance specifications of the monitor (i.e., within ± 2.5 percent of span for an SO_2 or NO_X monitor, ± 0.5 percent CO_2 or O_2 for a diluent monitor, or ± 3.0 percent of span for a flow monitor). Non-routine calibration adjustments would be permitted, provided that an acceptable technical justification is included in the QA/QC program required under section 1 of Appendix B. An additional calibration error test would be required following non-routine adjustments, to demonstrate that the instrument is still operating within its performance specifications.

In addition to the daily calibration error requirements in section 2.1.1 of Appendix B, today's proposed rule would require a calibration error test in four specific instances: (1) whenever a daily calibration error test is failed; (2) when a CEMS is returned to service following routine or corrective maintenance that may affect the ability of the CEMS to accurately measure and record emissions data; (3) following routine calibration adjustments in which the monitor's calibration is physically adjusted, e.g., by means of a potentiometer (however, an additional calibration error test would not be required if a mathematical algorithm in the DAHS is used to make the routine adjustments); and (4) following non-routine calibration adjustments. Data from the CEMS would be considered invalid until the required additional calibration error test had been successfully completed.

EPA is proposing to allow non-routine calibration adjustments within the performance specifications of an instrument for two principal reasons. First, commenters have expressed concern that restricting allowable adjustments to routine calibration adjustments would limit their ability to make adjustments within the acceptable plus or minus control limits of a monitor, particularly prior to linearity tests and RATAs. They have indicated that this flexibility is necessary because the tag values of reference gases are not 100.0 percent accurate and adjustments of the analyzer may be needed to account for these inaccuracies (see Docket A–97-35, Item II–I–15). EPA agrees that this is a legitimate concern. Because there is a tolerance of ± 2.0 percent on the different reference gases used for daily calibration error tests, linearity tests, and RATAs, it may be necessary to adjust toward or away from the tag value in order to make sure that the test specifications are met. The Agency believes, however, that it is appropriate to limit the calibration adjustments to within the instrument's performance specifications (i.e., ± 2.5 percent of span (for SO_2 and NO_X), ± 3.0 percent of span (for flow rate), and ± 0.5 percent CO_2 or O_2) in order to provide an on-going demonstration that the CEMS can simultaneously comply with the applicable daily, quarterly, semiannual, or annual performance specifications in Appendix A. One utility has expressed concern about its vendor's practice of making large calibration adjustments to the CO_2 monitor prior to RATA testing (see Docket A–97–35, Item II–D–63).

The second reason for proposing to allow non-routine calibration adjustments is the sensitivity of dilution-extractive monitors to changes in barometric pressure, temperature, and molecular weight. EPA believes that the best way to deal with this deficiency in the dilution-extractive monitoring technology is to develop a mathematical algorithm (site-specific, if necessary) that continuously applies a correction to the measurement in order to compensate for pressure, temperature, and molecular weight, as necessary, and to program the algorithm into the DAHS. However, in commenting on a pre-proposal draft of today's proposed rule, a number of utilities indicated that they prefer to account for dilution probe pressure effects by manually adjusting the monitor's calibration in anticipation of barometric pressure changes (e.g., approaching weather fronts) (see Docket A–97–35, Items II–D–41, II–D–55). After much deliberation, the Agency is proposing to allow such adjustments, provided that: (1) the calibration of the monitor is not adjusted outside of its performance specifications; (2) an additional calibration error test is done to verify that the adjustments have been properly made; and (3) the procedures used for the adjustments are included in the QA/QC program for the CEMS. Despite this, EPA still prefers that automatic pressure, temperature, and molecular weight compensation be used, where necessary, and would strongly encourage all facilities with dilution-extractive monitors to develop and apply the necessary mathematical algorithm(s).

2. Linearity Tests

Today's proposal would provide rules for data validation during linearity tests, in proposed section 2.2.3 of Appendix B. A routine quality assurance linearity test could not be commenced if the CEMS were operating ''out-of-control'' with respect to any of its other daily, semiannual, or annual quality assurance tests. Linearity tests would be done ''hands-off,'' as follows. 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 test period, however, no adjustment of the monitor would be permitted except for routine daily calibration adjustments following successful daily calibration error tests (the Agency notes that it is unlikely for calibration error tests to be done during a linearity test period except when two or more operating days are required to complete the test, e.g., for a peaking unit).

Proposed section 2.2.3 of Appendix B would specify that when a linearity check is 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 hands-off linearity test. This proposed requirement is not substantially different from the out-of-control provision in the current rule. It would merely extend the definition of out-of-control to include linearity tests that are aborted prior to completion due to a problem with the monitor. The underlying assumption is that the aborted linearity test would not have been passed if all nine gas injections had been completed. However, a linearity test that is aborted for a reason unrelated to a monitor malfunction (e.g., an unplanned or forced unit outage) would not trigger an out-of-control period.

Finally, a new section, 2.2.4, would be added to Appendix B, providing a linearity test grace period of 168 unit operating hours. The purpose of the grace period would be to give the owner or operator a window of opportunity in which to perform a linearity test, when either: (1) the required linearity test cannot be completed within the QA operating quarter in which it is due, or (2) four consecutive calendar quarters have elapsed since the end of the calendar quarter in which a linearity test of a monitor (or range) was last done. Data validation during a grace period would be done according to the applicable provisions of proposed section 2.2.3 of Appendix B. Proposed section 2.2.4 of Appendix B would specify that if the required linearity test has not been completed within the grace period, data from the monitor would become invalid, beginning with the first hour following the expiration of the grace period and would remain invalid until the hour of completion of a subsequent successful, hands-off linearity test. Proposed section 2.2.4 would further specify that a linearity test done during a grace period could only be used to meet the linearity test requirement of a previous QA operating quarter, not the requirement of the quarter in which the grace period is used. Note that proposed sections 2.2.3 and 2.2.4 of Appendix B would also extend the 168 unit operating hour grace period to apply to the quarterly leak checks of differential pressure-type flow monitors.

3. RATAs

Today's proposal would provide rules for data validation during gas and flow monitor RATA tests, in section 2.3.2 of Appendix B. Proposed section 2.3.2 would specify that a routine quality assurance RATA could not be commenced if the monitoring system is out-of-control with respect to any of its daily quality assurance assessments, including the additional calibration error test requirements of proposed section 2.1.3 of Appendix B. All RATAs would be done ''hands-off,'' as follows. Prior to the RATA , both routine and non-routine calibration adjustments would be permitted, in accordance with proposed section 2.1.3 of Appendix B. During the RATA test period, however, only routine calibration adjustments (as defined in proposed section 2.1.3 of Appendix B) would be permitted. For 2-level and 3-level flow RATAs, no linearization of the monitor would be permitted between load levels.

Note that EPA is proposing to allow pre-RATA adjustments and linearization of a CEMS, principally to encourage facilities to optimize the performance of their CEMS by achieving the best possible relative accuracy results in a cost-effective manner with little or no data loss. The Agency believes that there is no significant risk in allowing pre-RATA adjustments, provided that the monitor's continued accuracy between successive RATAs can be reasonably established. For gas monitors, EPA believes that the daily calibration error tests and quarterly linearity tests, which challenge the analyzers with protocol gases of known concentration, provide that assurance. For flow monitors, however, the daily calibration error tests, which check the internal electronics of the flow monitor but do not evaluate the actual flow measurement capability of the instrument, do not provide the necessary assurance. Therefore, in today's rulemaking, EPA is proposing a new flow monitor quality assurance requirement, the ''flow-to-load test,'' to provide a reasonable indicator of continued flow monitor accuracy between successive RATAs. The flow-to-load test has been discussed in detail under section III.M. of this preamble.

If a RATA is failed or aborted due to a problem with the CEMS, proposed section 2.3.2 of Appendix B would specify that the monitoring system is out-of-control as of the hour in which the test is failed or aborted. Data from the monitoring system would remain invalid until the hour of completion of a subsequent successful hands-off RATA. This proposed requirement is essentially the same as the out-of-control provision in the current rule, except that it would extend the definition of out-of-control to include RATAs that are aborted prior to completion due to a problem with the CEMS. Note, however, that a RATA which is terminated for a reason unrelated to monitor malfunction (e.g., process operating problems or unit outage) would not trigger an out-of-control period.

For multiple-load flow RATAs, each load level would be treated as a separate RATA. Therefore, if a flow RATA is failed at a particular load level, previously-passed RATAs at the other loads would not have to be repeated unless the flow monitor has to be re-linearized. In that case, a subsequent 3-load RATA would be required.

If a daily calibration error test is failed during a RATA test period, proposed section 2.3.2 of Appendix B would require invalidation of the RATA, and an out-of-control period would begin with the hour of the failed calibration error test. The RATA could not to be re-started until a subsequent calibration error test had been passed, following corrective actions.

Proposed section 2.3.2 of Appendix B further specifies that when the RATA of a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) is failed and that same CO_2 (or O_2) monitor also serves as the diluent component in a NO_X-diluent (or SO_2-diluent) monitoring system, then both the CO_2 (or O_2) monitor and the associated NO_X-diluent (or SO_2-diluent) system would be considered to be out-of-control until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems are in-control and have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of Appendix A. The beginning of the out-of-control period for each monitoring system would be the hour of completion of the failed or aborted RATA of the CO_2 (or O_2) monitor. The lengths of the out-of-control periods would, therefore, be determined from the same reference point for both the CO_2 (or O_2) monitoring system and the NO_X-diluent (or SO_2-diluent) monitoring system.

Today's proposal would clarify the way in which RATA results are to be reported to EPA in the electronic quarterly report required under § 75.64. Proposed section 2.3.2 of Appendix B specifies that only the results of completed and partial RATAs that affect data validation would have to be reported. That is, all completed passed RATAs, all completed failed RATAs, and all RATAs aborted due to a problem with the CEMS would have to be included in the quarterly report. Therefore, aborted RATA 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. RATAs which are aborted or invalidated due to problems with the 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 is performed, and (2) no adjustments other than the calibration adjustments allowed under proposed section 2.1.3 of Appendix B are made. However, such RATA runs would still have to be documented and kept on-site as part of the official test log.

Whenever a required RATA has not been completed by its deadline, section 2.3.3 of Appendix B of today's proposed rulemaking would provide a grace period of 720 unit operating hours in which to complete the test. Data validation during a grace period would be done according to the applicable provisions of proposed section 2.3.2 of Appendix B. Proposed section 2.3.3 would specify that if the RATA is not completed by the end of the grace period, data from the CEMS would become invalid upon expiration of the grace period and remain invalid until the hour of completion of a subsequent successful hands-off RATA.

EPA has proposed a 720 unit operating hour RATA grace period because the Agency believes this will allow the facility sufficient time to schedule the RATA, to provide all required test notifications, and to complete the testing. The proposed grace period would be based on unit operating hours rather than clock hours, because this is believed to be more equitable for peaking and cycling units. Data validation during the grace period would be prospective, i.e., data from the monitoring system would be considered valid during the grace period until the time of the RATA. If the RATA is failed or aborted due to a problem with the CEMS, data would be invalidated from the hour in which the test is failed or aborted, forward. Data would not be invalidated retrospectively back to the beginning of the grace period. Several utilities have expressed a preference for a grace period with prospective data invalidation, because it is simple to implement and is consistent with other part 75 provisions for which data invalidation is prospective when a test is failed (see Docket A–97–35, Item II–E–23).

4. Recertification of Gas and Flow Monitors

Today's proposed rule would revise § 75.20(b)(3) concerning data validation during recertification test periods. In the January 11, 1993 rule, as amended on May 17, 1995, § 75.20(b)(3) specifies that for any replacement, change, or modification to a monitoring system requiring recertification of the CEMS, all data from the CEMS are considered invalid from the hour of that replacement, change, or modification until the hour of completion of all required recertification tests. Today's rulemaking proposes 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 allow these new data validation procedures to also be applied to the initial certification of monitoring systems. The proposed revisions are based, in part, on policy guidance issued by EPA to address the initial certification of CEMS when a wet scrubber is installed on an affected unit (see Docket A–97–35, Item II–I–9, Policy Manual, Question 16.10). The intent of that policy guidance and of today's proposal 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 are provided for data validation during the recertification test period. The recertification test period would begin with the first successful calibration error test after making the change to the CEMS and completing all necessary post-change adjustments, re-programming, linearization, etc. of the CEMS. The post-change activities could also include preliminary tests such as trial RATA runs or a challenge of the monitor with calibration gases. The first successful calibration error test following all of these activities would be known as a probationary calibration error test. 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.

Today's proposal would place a specific time limit on the length of the recertification test period, depending upon the type(s) of test(s) required. If a linearity test or cycle time test is required, the test would have to be completed within 168 unit operating hours of the hour in which the probationary calibration error test was passed, marking the beginning of the recertification test period. If a RATA is required, it would have to be completed within 720 unit operating hours. If a 7-day calibration error test were required, it would have to be completed within 21 unit operating days. Routine daily calibration error tests would continue to be done as required by part 75 throughout the recertification test period. If a particular recertification test is not completed within the specified number of hours, data validation would be done as follows. For a late linearity test, RATA, or cycle time test that is passed on the first attempt, or for a late 7-day calibration error test (whether or not it is passed on the first attempt), data from the monitoring system would be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. However, 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 would be invalidated from the hour of the probationary calibration error test that initiated the original recertification test period to the hour of completion of the late recertification test. Data would remain invalid until successful completion of the failed/aborted test and any additional recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct the problem(s) that caused failure of the late recertification test.

A conditionally valid status would be assigned to emission data generated by a CEMS during a recertification test period. The conditionally valid data status would begin with the first hour of the recertification test period (i.e., the hour in which the probationary calibration error test is passed, following completion of all necessary monitor adjustments, preliminary tests, etc.). The conditionally valid status of the CEMS data would continue throughout the recertification test period, provided that the required recertification tests are done "hands-off" (i.e., with no adjustments, reprogramming, etc. 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 continue to be passed. If all of the required recertification tests and calibration error tests are 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. Note, however, that if a required recertification test has not been completed by the end of a calendar quarter, the owner or operator would indicate this by using a suitable conditional data flag in the electronic quarterly report for that quarter. The owner or operator would be required to resubmit the report for that quarter if the required recertification test is subsequently failed. In the resubmitted report, the owner or operator would use the appropriate missing data routine in § 75.31 or § 75.33 to replace each hour of conditionally valid data that was invalidated by the failed recertification test with substitute data. In addition, if conditionally valid data is submitted to the Agency in any quarterly report, the owner or operator would have to indicate in the end of the year compliance report required under § 72.90 whether the final status of the conditionally valid data has been determined. Note that in certain instances where a recertification test period spans two calendar quarters, it may be possible to avoid use of the conditional data flag and quarterly report resubmittal. If a required recertification test(s) is completed no later than 30 days after the end of a calendar quarter (i.e., prior to the quarterly report submittal deadline), the test data and results may be submitted with the quarterly report, even though the test dates are from the next calendar quarter. If the recertification test(s) is passed, this would allow the ''conditionally valid'' data to be reported as quality assured, in lieu of using a conditional data flag. If the test(s) is failed, conditionally valid data could be replaced with substitute data, as appropriate, and resubmittal of the quarterly report would not be necessary.

If a recertification test is failed or aborted due to a problem with the CEMS or if a routine daily calibration error test is failed during a recertification test period, proposed § 75.20(b)(3) specifies that data validation would be done as follows:

(1) If any required recertification test is failed, the test would have to 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 would end and any necessary maintenance activities, adjustments, linearizations, and reprogramming of the CEMS would need to be completed before a new recertification test period could begin. The new recertification test period would begin with a probationary calibration error test. The tests that would be required in this new recertification test period would include any tests that were required for the initial recertification event which were not successfully completed and any recertification or diagnostic tests required as a result of changes that were made to the monitoring system to correct the problems that caused failure of the recertification test;

(2) If a linearity test, 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 would be invalidated from the hour of commencement of the original recertification test period to the hour in which the test is failed or aborted. Data from the CEMS would remain invalid until the hour in which a new probationary calibration error test is passed following all of the necessary maintenance procedures, diagnostic tests, etc., at which time the conditionally valid status of emission data from the CEMS would begin;

(3) If a 7-day calibration error test is failed within the recertification test period, the test would have to be re-started. Previously-recorded conditionally valid emission data from the CEMS would not be invalidated by a failed 7-day calibration error test unless the calibration error on the day of the failed 7-day calibration error test exceeded twice the performance specification in section 3 of Appendix A (causing the monitor to be considered out-of-control); and

(4) If a calibration error test is failed during a recertification test period, the CEMS would be considered out-of-control as of the hour in which the calibration error test is failed. Emission data from the CEMS would 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 data status would resume. Failure to perform a required daily calibration error test during a recertification test period would 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. Following a failed or missed calibration error test, no recertification tests could be performed until the required subsequent calibration error test had been passed.

5. Recertification and QA

In today's proposed rule, a new section, 2.4, entitled ''Recertification, Quality Assurance, and RATA Deadlines'' would be added to Appendix B. The purpose of this section would be to clarify the inter-relationship between normal quality assurance testing of CEMS and recertification events and to further clarify how RATA deadlines are determined. Appendix B to part 75 currently requires periodic (daily, quarterly, and semiannual or annual) quality assurance tests of all CEMS. The required daily QA tests include calibration error tests of all monitors and interference checks of flow monitors. Quarterly QA tests include linearity checks of gas monitors and leak checks of differential pressure-type flow monitors. The required semiannual or annual QA tests for all types of CEMS are RATAs.

Under the current rule, when a significant change is made to a CEMS which affects the ability of the monitoring system to accurately read and record emissions data, § 75.20(b) specifies that the CEMS must be recertified. To recertify a monitoring system, one or more of the following tests that were performed for initial certification of the CEMS must be repeated. That is, depending upon the nature of the change made to a CEMS, one or more of the following tests may be required for recertification: (1) calibration error test, (2) cycle time test, (3) linearity check, (4) RATA, or (5) DAHS verification. Notice that recertification tests (1), (3), and (4) are the same types of tests that are done for routine daily, quarterly, and semiannual or annual QA. There is, therefore, a connection between routine QA tests and recertification tests. Proposed § 75.20(b) would further clarify that any change to a CEMS that does not require a RATA would not be considered a recertification event, and, therefore, would not require a recertification application. In such cases, the required tests would be considered diagnostic tests.

Routine QA tests are generally planned and scheduled in advance, while recertification tests are performed on an as-required basis. Despite this, it is sometimes possible to coordinate component replacements or other changes to a CEMS with the QA test schedule for the CEMS. For instance, suppose that in a particular quarter, a CEMS component is replaced, and a RATA is required to recertify the monitoring system. Suppose, further, that in the quarter of the component replacement, the annual RATA is due, but has not yet been conducted. In this case, the recertification RATA could serve a dual purpose, i.e., to recertify the CEMS and to meet the annual RATA requirement. For this reason, EPA proposes to recommend in today's rule that, to the extent practicable, component replacements, system upgrades, and other events that require recertification be coordinated with the periodic (daily, quarterly, and semiannual or annual) QA testing required under Appendix B. Proposed section 2.4 of Appendix B clarifies that when a particular test is done for the dual purpose of recertification and routine QA, the data validation rules in § 75.20(b)(3) pertaining to recertification would take precedence and would be followed. In a similar manner, a required diagnostic test (e.g., linearity check) could also be used to satisfy a quarterly linearity test requirement.

Proposed section 2.4 of Appendix B emphasizes that, in general, whenever a RATA is performed, whether for QA purposes, recertification purposes, or both, the projected deadline for the next RATA (i.e., whether the next test is due in 2 or 4 QA operating quarters) would be established based upon the percentage relative accuracy obtained. For 2-load and 3-load flow RATAs, the projected deadline for the next RATA would be established according to the highest relative accuracy at any of the loads tested. There would, however, be two important exceptions to this for single-load flow RATAs. Irrespective of the relative accuracy percentage obtained, the results of a single-load flow RATA could only be used to establish an annual RATA frequency if: (1) the single-load flow RATA is specifically required under section 2.3.1.3(b) of Appendix B for flow monitors installed on peaking units and bypass stacks, or (2) the single-load RATA is allowed under proposed section 2.3.1.3(c) of Appendix B for ≥ 85.0 percent historical unit operation at a single-load level. No other single-load flow RATA could be used to establish an annual frequency; however, a 2-load flow RATA could be performed in place of any required single-load RATA, in order to achieve an annual frequency.

6. Data From Non-Redundant Backup Monitors

Today's rule proposes to revise the quality assurance and data validation requirements in § 75.20(d) for non-redundant backup monitoring systems. Under the May 17, 1995 rule, a ''non-redundant backup monitoring system'' is defined as a ''cold'' backup monitoring system which is brought into service on an as-needed basis, rather than being operated continuously. Non-redundant backup monitors must be initially certified at each location at which they are to be used, but unlike ''redundant backup'' monitors which are operated continuously and kept on ''hot-standby,'' non-redundant backup systems are not required to meet the daily and quarterly quality assurance requirements of Appendix B, except when they are actually used for data reporting. A linearity test of each non-redundant backup gas monitor is required before it is placed in service, and each non-redundant backup flow monitor must pass a calibration error test before being used to report data. The use of non-redundant backup monitors is restricted to 720 hours a year at a particular unit or stack, unless a 7-day calibration error test is passed. A periodic recertification RATA of each non-redundant backup monitor is required at least once every two years, at each location where it is to be used.

Section 75.20(d) of today's proposal would clarify and expand the definition of a non-redundant backup monitoring system. Under the proposal, two distinct types of non-redundant backup systems would be defined: (1) type-1 is a system that has its own separate probe, sample interface, and analyzer (e.g., a portable gas monitoring system), and (2) type-2 is a system consisting of one or more like-kind replacement analyzers that use the same sample probe and interface as the primary monitoring system. This would include non-redundant backup analyzers that are used to meet the dual span and range requirements for SO_2 or NO_X under proposed sections 2.1.1.4 and 2.1.2.4 of Appendix A.

The ''type-1'' system is the familiar non-redundant backup system described in the current version of part 75. However, the ''type-2'' system is a new kind of non-redundant backup monitoring system. EPA believes that allowing limited use of type-2 monitoring systems will encourage facilities that do not have redundant backup monitors to perform better maintenance on their primary analyzers. The Agency is concerned that primary analyzers with excessive, recurring daily calibration drift (i.e., monitors that fail calibration error tests more often than expected) are sometimes kept in service to avoid using substitute data, when the analyzers should be in the shop for maintenance. If the monitor readings tend to drift low from day to day, this can result in under-reporting of emissions, because data validation for daily calibrations under part 75 is prospective. That is, data are invalidated from the hour of a failed calibration error test forward, while data recorded from the hour of the previous successful calibration to the hour of the failed calibration are considered valid. EPA believes that allowing limited use of type-2 non-redundant backup monitoring systems would provide a simple way (i.e., like-kind analyzer replacement) for primary analyzers to be properly maintained and repaired with minimal data loss.

Today's proposal would retain the requirement for type-1 non-redundant backup monitoring systems to be initially certified (except for a 7-day calibration error test) at each location at which they are to be used. However, type-2 systems would require no initial certification. Both types of systems would have to pass a linearity test (for gas monitors) or a calibration error test (for flow monitors) each time that they were used to report emission data. For a type-2 ''mix-and-match'' NO_X monitoring system consisting of one primary analyzer and one like-kind replacement analyzer, only the like-kind replacement analyzer would have to pass a linearity test, provided that the primary analyzer is operating and not out-of-control with respect to any of its quality assurance requirements. When a non-redundant backup monitoring system is brought into service, emission data from the non-redundant backup system could be deemed conditionally valid during the linearity test period, as follows. After making the like-kind replacement and prior to conducting the linearity test, a probationary calibration error test could be done to begin the period of conditionally valid data. If the linearity test is then passed within 168 unit operating hours of the probationary calibration error test, the conditionally valid data would be validated. However, if the linearity test is either failed, aborted due to a problem with the CEMS, or not completed as required, then all of the conditionally valid data would be invalidated beginning with the hour of the probationary calibration error test, and data from the non-redundant backup CEMS would remain invalid until the hour of completion of a successful linearity test.

Under today's proposal, when a non-redundant backup system is used for part 75 reporting, the bias adjustment factor (BAF) from the most recent RATA of the system would be applied to the data generated by the system. If no RATA results were available for a type-2 system, the primary monitoring system BAF would be applied to the data generated by the type-2 system.

Today's proposal would retain the restrictions of the current rule, which limit the annual usage of a non-redundant backup monitoring system to 720 hours at a particular location (unit or stack). To use a non-redundant backup system for more than 720 hours per year at a particular location would require a RATA of the system at that location. For type-1 systems, a recertification RATA would be required at least once every eight calendar quarters at each location at which the system is to be used. All non-redundant backup monitoring systems (type-1 and type-2) would have to be assigned unique system and component identification numbers and would have to be included in the monitoring plan for the unit or stack.

7. Missed QA Test Deadlines

As discussed above under the subsections on ''Linearity Tests'' and ''Relative Accuracy Test Audits,'' proposed sections 2.2.4 and 2.3.3 of Appendix B to today's rulemaking would allow a grace period in which to perform required linearity tests and RATAs whenever a test cannot be completed by the end of the quarter in which it is due. EPA believes it is appropriate to allow a grace period because circumstances beyond the control of the owner or operator (e.g., unplanned unit outages) sometimes arise which prevent the deadline for a quality assurance test from being met.

The proposed linearity grace period is 168 unit operating hours, and the proposed RATA grace period is 720 unit operating hours. A linearity grace period could only be used to satisfy the linearity requirement from a previous quarter. For any RATA (or RATAs, if more than one attempt is made) conducted during a grace period, the deadline for the next RATA would be calculated from the quarter in which the RATA was originally due, not from the quarter in which the RATA is actually completed.

Data validation during a grace period would be done according to the applicable provisions in proposed section 2.2.3 of Appendix B (for linearities) or section 2.3.2 of Appendix B (for RATAs). Data from a CEMS would become invalid upon expiration of a grace period if the required linearity test or RATA had not been completed. Data from the CEMS would remain invalid after the expiration of the grace period until the required test is successfully completed.

P. Appendix D

1. Pipeline Natural Gas Definitions

Background

Appendix D provides an optional protocol by which oil-fired and gas-fired units may account for their SO_2 mass emissions. Under the definitions of ''oil-fired'' and ''gas-fired'' in § 72.2, Appendix D may be used to measure SO_2 emissions from gaseous fuels only if the gaseous fuel's sulfur content is less than or equal to that of natural gas.

In developing Appendix D, EPA assumed that virtually all of the gaseous fuel combusted by affected units in the Acid Rain Program would be pipeline natural gas. Section 2.3 of Appendix D of the January 11, 1993 rule allowed for accounting for SO_2 emissions from gaseous fuel using EPA's ''National Allowance Database (NADB) emission rate.'' The NADB was used to establish a baseline of historical SO_2 emissions in order to allocate allowances. For the vast majority of units combusting pipeline natural gas, NADB used the historical heat input from gas and an emission rate of 0.0006 pounds of SO_2 per measured million British thermal units (lb/mmBtu) (see Docket A–92–06; Docket A–94–16, Item II–F–2). This default factor is derived from EPA Publication AP–42 and is based on a sulfur content of 0.2 grains per 100 standard cubic feet of gaseous fuel (gr/100 scf) (see Docket A–97–35, Item II–I–1). Use of this default SO_2 emission rate factor for pipeline natural gas was clarified by EPA in its Acid Rain Policy Manual (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.4).

Section 2.3.2 of Appendix D, as revised by the May 17, 1995 direct final rule, explicitly allows owners or operators to use a default emission factor of 0.0006 (lb/mmBtu) to estimate SO_2 emissions during hours in which pipeline natural gas is combusted. Alternatively, section 2.3.1 of Appendix D, also as revised by the May 17, 1995 direct final rule, allows for determining SO_2 emissions from any gaseous fuel with a sulfur content no greater than natural gas by performing daily fuel sampling, analyzing the sulfur content of the gaseous fuel, and multiplying that sulfur content in grains per 100 standard cubic feet (gr/100scf) times the volume of gaseous fuel combusted. Units combusting gaseous fuels with a total sulfur content greater than natural gas (i.e., > 20 gr/100scf) are not allowed to use the procedures of Appendix D and must instead use an SO_2 CEMS and a flow monitor to determine SO_2 mass emissions. This limitation is explicitly stated in § 75.11(e)(4), as revised on November 20, 1996.

The definition of ''natural gas'' in § 72.2, as revised by the May 17, 1995 direct final rule, indicates that the sulfur content of natural gas is ''1 grain or less hydrogen sulfide per 100 standard cubic feet, and 20 grains or less total sulfur per 100 standard cubic feet.'' This definition was taken from Requirements of the Federal Energy Regulatory Commission (FERC) for regulation of the transmission of natural gas. ''Pipeline natural gas'' is also defined in § 72.2. However, the definition is simply ''natural gas that is provided by a supplier through a pipeline,'' and provides no specifications for sulfur content or hydrogen sulfide content.

Section 2.3.2.2 of Appendix D requires documentation of the contractual sulfur content of pipeline natural gas from the supplier. This documentation was intended to demonstrate that the natural gas is supplied through a pipeline, as well as that it meets the sulfur content definition for natural gas.

Questions over the applicability of Appendix D and the apparent inconsistencies between the definitions ''natural gas'' and ''pipeline natural gas'' in § 72.2 and the provisions of section 2.3 of Appendix D have caused confusion during program implementation since the May 17, 1995 direct final rule. Some utilities have interpreted section 2.3.2.2 of Appendix D to allow pipeline natural gas to have a sulfur content as high as 20 gr/100 scf, which is one hundred times higher than the sulfur content upon which the 0.0006 lb/mmBtu emission factor is based. During the process of applying for certification of monitoring equipment for six gas-fired units, one utility indicated to the Agency that it intended to use a default emission rate of 0.0006 lb/mmBtu and heat input to account for SO_2 mass emissions from propane liquefied petroleum gas (see Docket A–97–35, Item II–D–6). Based upon the information provided by the utility in its monitoring plan for the units, the sulfur content of propane was several times higher than that of pipeline natural gas, with a range of sulfur content between 0.08 and 2.72 gr/100 scf, compared to a typical sulfur content of 0.2 gr/100 scf for pipeline natural gas, upon which the default SO_2 emission rate of 0.0006 lb/mmBtu is based. Later information submitted by the utility indicated that during the previous three years, the sulfur content of propane combusted at that plant had an average value of 0.83 gr/100 scf and a maximum value of 2.20 gr/100 scf (see Docket A–97–35, Item II–D–60). EPA rejected the utility's monitoring approach using the default emission rate for pipeline natural gas because it would have resulted in an underestimation of SO_2 emissions, as well as not following the procedures of Appendix D (see Docket A–97–35, Item II–C–2).

Other utilities have tried to use the default SO_2 emission rate of 0.0006 lb/mmBtu for higher sulfur gaseous fuels, such as digester gas (see Docket A–94–16, Item II–D–71). EPA issued policy guidance to ensure that other utilities were aware that the default SO_2 emission rate of 0.0006 lb/mmBtu should only be used for pipeline natural gas with a low sulfur content of 0.2 gr/100 scf (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.15, as originally published in March 1996). However, several utilities were concerned that this excluded some pipeline natural gas (see Docket A–97–35, Items II–B–3, II–E–16). As stated in the technical support document for the May 17, 1995 direct final rule, EPA had intended that all pipeline natural gas would qualify for use of the default SO_2 emission rate of 0.0006 lb/mmBtu. Therefore, the Agency revised its guidance to clarify that a facility needed only to document that it was using pipeline natural gas, without documenting a sulfur content of 0.2 gr/100 scf (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.15, as revised in June 1996). During this process, the Agency became concerned that the definition of pipeline natural gas in § 72.2 was not clear enough and that the sulfur content documentation required for pipeline natural gas in section 2.3.2.2 of Appendix D was confusing and possibly inappropriate.

Discussion of Proposed Changes

For the definition of pipeline natural gas in § 72.2, today's proposal includes a revised definition that would indicate pipeline natural gas is low in the sulfur-bearing compound hydrogen sulfide (H_2S). The proposed revised definition would specifically include the maximum hydrogen sulfide content for pipeline natural gas permitted by fuel purchase or transportation contracts. The hydrogen sulfide content of pipeline natural gas is proposed to be up to 0.3 gr/100 scf.

In addition, section 2.3 of Appendix D would be revised. As under the current rule provisions, sources would be allowed to use a default SO_2 emission rate of 0.0006 lb SO_2/mmBtu in conjunction with unit heat input to calculate the SO_2 mass emission rate during the combustion of pipeline natural gas. In order to demonstrate that the pipeline natural gas qualifies to use the default SO_2 emission rate of 0.0006 lb/mmBtu, it would be necessary for the designated representative to provide information in the monitoring plan on the gas's maximum hydrogen sulfide content from the facility's purchase contract with the pipeline gas supplier or from the pipeline natural gas supplier's transportation contract. In such contracts, or in the tariff sheets associated with them, the pipeline gas supplier typically agrees to provide natural gas with a maximum hydrogen sulfide content of 0.25 gr/100 scf or 0.30 gr/100 scf. If a facility has previously submitted contract information from its pipeline gas supplier containing a limit on the sulfur content, this information typically also verifies the limit on the hydrogen sulfide content. For pipeline natural gas, it would not be necessary to provide sampling information to verify that the hydrogen sulfide content actually meets the quality specification limit on the hydrogen sulfide content stated in the definition of pipeline natural gas.

If a facility wanted to demonstrate that another gaseous fuel had an SO_2 emission rate no greater than pipeline natural gas, and thus, could use the default emission rate factor of 0.0006 lb/mmBtu, the designated representative would provide sulfur content and GCV information in the monitoring plan for the unit or could petition under § 75.66(i) after initial certification for the unit. It would be necessary for the designated representative to demonstrate that the gaseous fuel has an SO_2 emission rate no greater than 0.0006 lb/mmBtu. The designated representative would need to provide at least 720 hours of data for the demonstration. The data could come from the fuel supplier, if the fuel came from a gas supplier.

For all units using Appendix D, proposed section 2.3.3 would require the designated representative to provide information to the Agency demonstrating that the total sulfur content of the gaseous fuel meets the requirements of Appendix D and that the unit meets the § 72.2 definition of "gas-fired" or "oil-fired." Additionally, the gas-fired definition would be revised to indicate that the restriction of burning gaseous fuels containing no more sulfur than natural gas is actually a restriction on the total sulfur in the fuel. The gaseous fuel's total sulfur content would have to be shown to be less than or equal to 20 grains total sulfur per 100 standard cubic feet of gaseous fuel.

Rationale

The Agency proposes to introduce specific hydrogen sulfide content values into the definition of pipeline natural gas in order to provide a guideline that will separate gaseous fuels with a higher sulfur content from low sulfur pipeline natural gas. The maximum hydrogen sulfide content of 0.3 gr/100 scf is being proposed for two reasons. First, hydrogen sulfide contents of 0.25 or 0.3 gr/100 scf are typically required under pipeline gas transmission contracts, and should be relatively easy to document (see Docket A–97–35, Item II–E–19). In addition, 0.2 gr/100 scf is the sulfur content equivalent to the default emission rate factor of 0.0006 lb/mmBtu from the Agency's AP–42 emission factors that may be used by units combusting pipeline natural gas under section 2.3.2 of Appendix D (see Docket A–97–35, Item II–A–6). A maximum hydrogen sulfide content of 0.3 gr/100 scf corresponds to this default emission rate far more closely than a total sulfur content of 20.0 gr/100 scf or a hydrogen sulfide content of 1.0 gr/100 scf and, yet, would allow for some variability in the hydrogen sulfide content above a 0.2 gr/100 scf average. EPA believes that all or virtually all pipeline natural gas that is supplied through a pipeline for commercial use can meet these qualifications.

Pipeline natural gas is composed predominantly of methane (CH_4). Hydrogen sulfide is the predominant molecule containing sulfur in pipeline natural gas. Therefore, restricting the hydrogen sulfide content of pipeline natural gas to 0.3 gr/100 scf serves as a proxy for a limit on the total sulfur content, while being relatively easy to document. This revised definition of pipeline natural gas would also serve to restrict the default emission rate factor from being inappropriately applied to higher sulfur gaseous fuels, such as liquefied petroleum gas (see Docket A–97–35, Item II–D–6) or digester gas (see Docket A–94–16, Item II–D–71).

Appendix D of today's proposed rule would be revised to clarify the documentation requirements for sulfur content and hydrogen sulfide content of gaseous fuel, including pipeline natural gas. The original wording of section 2.3.2.2 implied that pipeline natural gas only need to have a total sulfur content of 20 gr/100 scf, roughly 100 times the sulfur content associated with the default emission rate of 0.0006 lb/mmBtu. Some utilities found this confusing (see Docket A–97–35, Items II–D–6, II–E–10). Therefore, EPA issued guidance to clarify that the default emission rate factor was only intended to apply to lower sulfur pipeline natural gas (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.15).

However, some utilities using pipeline natural gas were concerned that because their fuel suppliers were not willing to certify or agree to a sulfur content of 0.3 gr/100 scf by contract, they might be required to perform daily gas sampling (see Docket A–97–35, Items II–B–3, II–E–15, II–E–16). This was not the Agency's intent. The Agency merely wishes to ensure that facilities provide adequate documentation to demonstrate that the unit will not be underestimating SO_2 emissions for a high sulfur gaseous fuel by using an inappropriate default emission rate factor that applies to extremely low sulfur gas. Similar to EPA's Policy Manual Question 2.15 referred to above, a facility would need only to provide the fuel quality specification for total sulfur content and hydrogen sulfide from the pipeline supplier, or from the tariff sheet for the pipeline, in order to qualify to use the default emission rate.

If a facility intends to use the default emission rate factor for a gaseous fuel other than pipeline natural gas, sulfur content and GCV data would have to be provided and analyzed to demonstrate that the fuel has an SO_2 emission rate no greater than 0.0006 lb/mmBtu. A minimum of 720 hours of data would be required for the demonstration. Each hourly value of the total sulfur content (in gr/100 scf) would be divided by the GCV value (in Btu/100 scf) and then multiplied by a conversion factor of 10^6 Btu/mmBtu. This would provide a ratio of the number of grains of sulfur in the fuel to the heat content of the fuel. For pipeline natural gas with an assumed SO_2 emission rate of 0.0006 lb/mmBtu, a sulfur content of 0.2 gr/100 scf and a

GCV value of 100,000 Btu per hundred scf, the value of the ''sulfur-to-heat content'' ratio is 2.0 gr/mmBtu. Therefore, a candidate gaseous fuel would qualify to use the default SO_2 emission rate of 0.0006 lb/mmBtu for part 75 reporting purposes if the 720 hours of historical data demonstrate that the mean value of the sulfur-to-heat content ratio is 2.0 gr/mmBtu or less.

To demonstrate that a unit qualifies to use Appendix D when combusting a gaseous fuel, the designated representative for the facility would be required to show that the gaseous fuel has a total sulfur content of 20 grains/100 scf or less. This demonstration would apply to all gaseous fuels. For gaseous fuels other than pipeline natural gas, the sulfur content information could come either from contractual information on the sulfur content based on routine vendor sampling and analysis or from historic fuel sampling data to show the gaseous fuel's sulfur content (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.15). For gaseous fuels that are produced in batches or lots with a relatively uniform sulfur content, such as liquefied petroleum gases, it would be sufficient to provide historical information on each batch over the past year. This approach was accepted by the Agency for six units combusting liquefied petroleum gas (see Docket A–97–35, Items II–C–14 and II–D–22).

In addition to documenting the total sulfur content of the fuel, the owner or operator would be required to submit certain other fuel-specific information. As previously noted, for units combusting pipeline natural gas, a designated representative would be required to provide contractual information to demonstrate that the natural gas is supplied under specification and has a hydrogen sulfide content less than or equal to 0.3 gr/100 scf. And historical data would have to be provided, as described above, to obtain permission to use the default SO_2 emission rate of 0.0006 lb/mmBtu for a fuel other than pipeline natural gas. For other gaseous fuels that are not produced in batches with relatively uniform sulfur content, such as gaseous fuel generated through an industrial process (e.g., digester gas from a paper mill), since the sulfur content of the gaseous fuel could be highly variable, section 2.3.3.4 of today's proposed revisions to Appendix D would require a minimum of 720 hours of historical data documenting the sulfur content of the fuel under representative operating conditions. This information would allow the Agency to determine how variable the sulfur content is and if the daily sampling procedure under section 2.3.1 of Appendix D is sufficient to capture this variability without allowing the underestimation of sulfur content. If the sulfur variability were too great, continuous sampling using a gas chromatograph and hourly reporting of sulfur content would be required under today's proposed rule.

2. Fuel Sampling

(a) *Fuel Oil.*

Background

Diesel fuel is distillate fuel oil of grades No. 1 or 2. Diesel fuel is heavily refined and has a much lower sulfur content and greater consistency than other grades of fuel oil. Section 2.2 of Appendix D to the May 17, 1995 direct final rule provides three options for sampling of diesel fuel and two options for sampling of other fuel oils. First, for all fuel oils, including diesel fuel, daily manual sampling is allowed. Second, diesel fuel and other fuel oils may also be sampled continuously using an automated sampler according to ASTM D4177–82 (Reapproved 1990), either using continuous drip sampling or flow proportional sampling. The samples would then be mixed to form a daily composite sample. Third, diesel fuel may be sampled ''as-delivered,'' upon receipt of a shipment. These sampling approaches were selected to ensure that sulfur content values would be as accurate as possible, would not underestimate SO_2 mass emissions, and would account for any variability in the sulfur content of fuel.

Many utilities have expressed concern about the cost of daily oil sampling (see Docket A–97–35, Items II–D–18, II–D–20, II–E–13, II–E–14). Some utilities indicated that for a unit that burns oil every day, the cost of daily oil sampling is greater than the cost of SO_2 CEMS and flow monitors. Furthermore, industry representatives provided information indicating that within a given shipment of fuel oil from a supplier, the variability in sulfur content is low (see Docket A–97–35, Items II–D–18 and II–D–59). Many companies already have state or Federal requirements for sampling of fuel from each truck delivery or in a storage tank on site at the plant whenever fuel is added to the storage tank (see Docket A–97–35, Item II–D–93). The storage tank is a tank at a plant that holds oil that is actually combusted by the unit on that day. In other words, no fuel will be blended between the time when a fuel lot is transferred to the storage tank and when the fuel is combusted in the unit. In other cases, such as EPA's NSPS regulations for industrial boilers under 40 CFR part 60, subpart Db, companies keep copies of fuel receipts from the supplier to indicate the sulfur content is below the required sulfur content. Based upon this information, EPA is proposing to reduce the required sampling frequency for fuel oil. This would be a significant reduction in burden and cost of using Appendix D, without causing underestimation of SO_2 emissions.

Discussion of Proposed Changes

Several utilities suggested that the Agency propose to allow sampling of each delivery of oil (see Docket A–97–35, Items II–D–18, II–D–20, II–E–13, II–E–22). Under this approach, either a facility or its supplier would sample each truck or barge containing oil before the fuel is transferred into a tank at the plant. If a delivery shipped in a group of trucks were purchased under the same order and were specified to have the same gross calorific value, density, and sulfur content, then only one sample would be necessary for the group of trucks. Samples taken by the supplier would not need to be split and kept on hand at the site. This approach is currently allowed only for diesel fuel under section 2.2.1.2 of Appendix D, but would be extended to apply to all fuel oils under today's proposed rule. This approach would be particularly useful to a facility that receives large, infrequent deliveries of fuel or to a facility that already has other State or Federal regulations requiring sampling of each truck or barge delivered to the plant.

A similar approach suggested by another industry representative, allowing facilities to use a sample of oil taken from a tank belonging to the supplier before the oil is delivered, is also proposed in today's rulemaking. The supplier could take the sample and the facility would be able to use that value as long as it keeps records of the fuel analysis results from the supplier. This approach would be particularly useful to a facility that receives a delivery of oil from a single supplier's tank that is shipped in many different trucks. This approach also would be useful for a small facility that would prefer to rely on samples taken by the supplier rather than taking its own samples and paying for their analysis.

Finally, the Agency proposes a third sampling approach, allowing a facility to sample oil manually from its storage tank at the plant whenever oil is added to the tank. This approach would yield samples that are more representative of the oil combusted because it would include any fuel remaining in the tank as well as all fuel added. Sampling from the storage tank at the plant would be useful to a facility that burns oil infrequently and adds oil to its storage tank infrequently. It also would be helpful where a facility already has other State or Federal regulations requiring sampling after adding fuel to the storage tank.

Both the ''before delivery'' and ''as delivered'' sampling approaches would require a sample for each ''lot'' of oil; consequently, a suitable definition of a ''lot'' is needed. For purposes of determining when an oil sample should be taken for the NSPS applicable to utility boilers, section 5.2.2.2 of Method 19 in Appendix A to 40 CFR part 60 relies on a definition of fuel ''lot'' developed by the American Society for Testing and Materials (ASTM). This definition states that ''the lot size of a product oil is the weight of product oil from one pretreatment facility and intended as one shipment (ship load, barge load, etc.).'' In essence, a lot is a single batch of oil that has uniform properties and is purchased from a single supplier and delivered to a buyer. Among those uniform fuel properties are gross calorific value, density, sulfur content, and viscosity. In today's rulemaking, EPA proposes to adopt this definition of a lot of oil for use in the Acid Rain Program.

The Agency also considered whether it is appropriate to keep the current approach of daily manual oil sampling as an option. Although it seems unlikely that facilities would choose daily sampling option if they have the three options of sampling by lot, sampling upon addition of fuel to a storage tank, or continuous sampling, a utility group has requested that EPA retain daily manual sampling as an option. The agency is, therefore, proposing to retain daily manual oil sampling as an option in Appendix D to allow facilities this additional flexibility. An industry representative suggested that EPA could define the oil combusted during a 24-hour period as a lot. For the reasons discussed below and in the section addressing sulfur content, density, and gross calorific values used in calculations, EPA is not incorporating this suggestion in today's proposed rule.

EPA also reconsidered whether it is necessary to require daily composite samples when samples are taken continuously with an automatic sampler. In today's proposal, the Agency is proposing that continuous samples may be composited on a weekly basis rather than daily. The Agency also considered allowing an even longer compositing period, such as a month, but is not proposing this option for the reasons discussed below. A weekly composite sample of oil that is sampled continuously would be an attractive option for a facility that wants the most representative and accurate sulfur content data possible. This also would be a useful option for those few facilities that receive oil via a pipeline, rather than in discrete lots.

Rationale

Facilities wish to be able to perform less frequent fuel sampling in order to save money. From the information EPA has examined over the previous year, the Agency believes that less frequent oil sampling can be technically justified. Based upon information provided by utilities, the sulfur content of a lot of oil varies from sample to sample, with a standard deviation of 0.036 percent S to 0.063 percent S, or 5.62 to 6.85 percent of the average sulfur content for all daily samples between deliveries (see e.g., Docket A–97–35, Item II–D–18). Density and gross calorific value of oil in a lot should vary even less than sulfur content, because sulfur is an impurity in the composition of the fuel and not an essential physical property of the oil, as is density. Furthermore, the difference between the sulfur content, density, gross calorific value, and carbon content of a fuel during the first daily sample after a new delivery is received and the average sulfur content, density, gross calorific value, and carbon content for all daily samples from between two deliveries is extremely small (see Docket A–97–35, Items II–B–18 and II–D–18 for supporting information). Therefore, the Agency expects that the variability of fuel characteristics within a lot is low enough that only a single representative sample is necessary for the lot. Data have indicated that there could be a significant difference in sulfur content between shipments, however (see Docket A–97–35, Items II–B–12, II–B–18 and II–D–18). The Agency believes that differences between lots, which could potentially result in the underestimation of SO_2 emissions, can be dealt with by selecting a conservative sulfur content, density, or gross calorific value that would not be exceeded in any sample, rather than retaining more frequent sampling requirements. Therefore, today's proposal incorporates this approach.

Prior to drafting today's proposed rule revisions, EPA requested comments on removing the option to perform daily manual oil sampling for Appendix D units. At least one utility group expressed interest in retaining the option to allow flexibility. The prime benefit to a facility from continuing to use daily manual sampling would appear to be that the facility could continue to use the same daily operating procedures and that reprogramming of a DAHS would not be necessary. Note that when using the approach of daily manual oil samples, a facility calculates SO_2 mass emissions using the highest sulfur content in the previous 30 daily oil samples. Therefore, this approach requires more frequent analysis than either the proposed weekly composite sample for continuous samples or the proposed sampling by lot, and provides less accurate and more conservative results. The Agency believes it would be simpler and less confusing for both the Agency and for the regulated community to deal with a smaller number of approaches to sampling and calculating SO_2 emissions. However, the Agency is retaining this option since at least some affected utilities want the flexibility to continue to use this option.

EPA also considered the suggestion to define a 24-hour period as a lot in order to allow facilities to continue to perform daily manual sampling. EPA is not proposing this approach because of the added complexity, compared to keeping the current language in section 2.2.4 of Appendix D concerning manual daily sampling of oil. If a lot were defined as an arbitrary 24-hour period, the other requirements in the current rule (e.g., conservative sulfur, gross calorific value, and density values used to calculate SO_2 mass emission rate and heat input rate) would need to be retained to ensure that SO_2 emissions were not underestimated. Furthermore, using the terminology of a ''lot'' for both a delivery and a period of time, while requiring different treatment of sample data from the two different types of ''lots,'' could potentially be confusing. It seems preferable to keep the current language for daily manual samples.

Because the Agency now believes it is appropriate to sample each fuel lot instead of sampling daily, the Agency reconsidered whether daily composite samples are necessary when a facility performs automated continuous sampling. Because continuous samplers take fuel samples multiple times each hour, they are highly representative of the oil being burned. Flow proportional samplers take samples automatically when a certain volume or mass of fuel has passed by, rather than during a particular time period. Generally, automatic samplers take multiple samples each hour; however, only one sample per hour is required under section 2.2.3 of Appendix D of the current rule. Even if the compositing time period is extended, the composite sample will be representative of the sulfur content, density, and gross calorific value of the oil between samples. Therefore, the Agency believes that the compositing period could be extended from a day to as long a period as a month. However, EPA believes that it is unlikely that any container for taking samples from an automatic sampler would be large enough to accommodate all automatic samples taken during a month. In addition, at least one industry representative suggested that weekly composite samples were appropriate (see Docket A–97–35, Item II–D–30). Therefore, in section 2.2.3 of today's proposed rule, EPA would extend the allowable length of the compositing period for automatic samples to one week. The Agency believes this will make automatic sampling less costly, while taking into account the physical limitations of sampling equipment.

(b) *Gaseous Fuels.*

Background

Section 2.3 of Appendix D, as revised in the May 17, 1995 direct final rule, provides only one approach for sampling gaseous fuel: under section 2.3.1, gaseous fuel sampling must be performed daily. Relatively few utilities perform daily sampling upon gaseous fuels, choosing instead to use a default SO_2 emission rate for pipeline natural gas. In part, this is because the vast majority of gaseous fuel used by power plants is pipeline natural gas. Under section 2.3.2 of Appendix D, facilities may calculate SO_2 mass emissions from pipeline natural gas using a default emission rate instead of performing fuel sampling. Because of the difficulty and potential danger of sampling gaseous fuel, gas sampling is generally conducted by the supplier, rather than by the facility.

Those few utilities combusting gaseous fuels other than pipeline natural gas have expressed concern about the difficulty and expense of daily sampling, particularly in comparison to the value of SO_2 allowances for low SO_2 emissions from relatively clean fuel (see, e.g., Docket A–97–35, Items II–E–11, II–E–20). For gaseous fuels that are delivered in discrete batches or ''lots,'' one would expect the gaseous fuel to behave like an ideal gas; sulfur should be evenly distributed throughout the batch. On this principle, the Ohio Environmental Protection Agency allowed a plant to take propane samples from each discrete delivery, rather than on a daily basis (see Docket A–97–35, Items II–C–14 and II–D–22).

Discussion of Proposed Changes

Today's proposal incorporates three different sampling approaches for gaseous fuels: sampling by lot, daily sampling, and continuous sampling with a gas chromatograph. For gaseous fuel that is delivered in discrete lots, such as liquefied petroleum gas, the gaseous fuel could be sampled either daily or for each lot delivered. Any gaseous fuels other than pipeline natural gas that are not delivered in discrete lots, such as digester gas or sour natural gas pumped directly from a field, would, at a minimum, need to be sampled daily. The samples could be taken either by the supplier or by the facility. However, if the average sulfur content and sulfur variability of such a fuel were too high (i.e., mean sulfur content > 7 gr/100 scf and standard deviation from the mean > 5 gr/100 scf, based on 720 hours of representative historical data), continuous sampling with a gas chromatograph and hourly reporting of sulfur content would be required.

Rationale

The approach of sampling upon a lot or discrete delivery of gaseous fuel is being incorporated into today's proposed rule for the following reasons. The Agency believes that discrete deliveries are sufficiently different from pipeline transmission of fuel that a different sampling approach is appropriate. According to the ideal gas law, all gas within an enclosed volume is mixed with a consistent composition; therefore, a single sample should be representative of all gas in the volume. Although gaseous fuels delivered by lot, such as liquefied petroleum gas, are higher in sulfur content and have a wider range of sulfur contents than pipeline natural gas, they still have relatively low sulfur contents compared to liquid and solid fuels. Thus, less frequent gas sampling appears appropriate, based on the small difference in the accuracy of calculated SO_2 mass emissions. For this same reason, the Agency allowed as-delivered sampling for diesel fuel in the May 17, 1995 direct final rule (see Docket A–94–16, Item II–F–2). Finally, because of the difficulty of sampling gaseous fuels, EPA believes that it is less burdensome and less dangerous if gas sampling is conducted by the gas supplier. It is the Agency's understanding that the sampling for a gas in a discrete delivery or lot is typically conducted once for the lot, rather than on a daily basis. Through a petitioning process, EPA has already allowed one utility to perform sampling upon a lot or discrete delivery of gaseous fuel (see Docket A–97–35, Items II–C–14 and II–D–22).

EPA is proposing to require daily or continuous sampling of gaseous fuels other than pipeline natural gas or the equivalent that are not shipped in discrete lots, such as sour natural gas pumped directly from a field, landfill gas, or digester gas. Such gaseous fuels cannot be guaranteed to be stable in sulfur content. Therefore, proposed section 2.3.3.4 in Appendix D would require a minimum of 720 hours of representative historical data to characterize the sulfur variability of such fuels. For the 720 hours of demonstration data, the mean value and standard deviation of the fuel sulfur content would be calculated. If the mean value does not exceed 7 gr/100 scf (equivalent to about 10 ppm of SO_2 emissions to the atmosphere), daily sampling would suffice. If the mean value is greater than 7 gr/100 scf, however, the variability of the sulfur content would be assessed in terms of the standard deviation. If the standard deviation exceeds 5 gr/100 scf, the sulfur variability would be considered too high and continuous sampling of the fuel with a gas chromatograph would be required. If continuous sampling were required, the owner or operator would have to implement a quality assurance program for the gas chromatograph. A copy of the QA plan would be kept on-site, suitable for inspection. For fuel with a low average sulfur content or a low sulfur variability, daily sampling would be sufficient. However, for gaseous fuel with a higher sulfur content, if the sulfur variability were too great, continuous sampling of the fuel with a gas chromatograph and hourly reporting of sulfur content would be required.

3. Sulfur, Density and Gross Calorific Value Used in Calculations

(a) Fuel Oil.

Background

The hourly SO_2 mass emissions rate due to combustion of oil is calculated using the mass flow rate of oil combusted and a sulfur content value from a sample. If a unit's oil flow rate is measured with a volumetric fuel flowmeter rather than a mass fuel flowmeter, then it will be necessary to determine the mass flow rate of oil from the volume of fuel and a density value from an oil sample. The heat input rate is calculated using the flow rate of oil multiplied by the gross calorific value (GCV) of a sample.

The sulfur content, density, and GCV used to calculate emissions and heat input depend upon the oil sampling method used. Some sampling methods are more accurate than others. For example, for flow proportional or continuous drip sampling, the actual sulfur content from a sample is used to calculate SO_2 mass emissions. However, when daily manual samples are taken under section 2.2.4 of Appendix D, a facility must use the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples, which is not necessarily the sulfur content of the fuel being burned at any particular time. For units where diesel fuel is sampled upon delivery, section 2.2.1.2 instructs a facility to calculate SO_2 emissions using the highest sulfur content of any oil supply combusted in the previous 30 days that the unit combusted oil. In daily manual sampling and as-delivered sampling, conservative sulfur values are used to avoid the possibility of underestimating SO_2 mass emissions due to variations in sulfur content. Gross calorific values are taken from the most recent sample, rather than using the highest value in the previous 30 days, because, for natural gas, GCV is more consistent than sulfur content.

Today's proposed rule includes changes to the sampling frequency for oil. Therefore, it is also necessary to make corresponding changes to the sulfur content, density, and GCVs to be used in calculations. For example, where oil samples would no longer be taken daily, it would be inappropriate to calculate SO_2 mass emissions based upon a certain number of daily samples. In developing today's proposal, EPA considered what fuel analysis data values for sulfur content, density, and GCV would be appropriate and consistent with the approaches for taking manual samples. The appropriate sulfur content, density, and GCV values were considered for manual samples taken from a storage tank at the facility whenever fuel is added to the tank, for samples taken from each lot before the delivery is transferred from tank trucks or barges, and for samples taken from the fuel supplier's storage tank.

Discussion of Proposed Changes

EPA has re-evaluated the sulfur content, density, and GCVs to be used to calculate SO_2 mass emissions and heat input based upon the new oil sampling approaches. For daily manual oil sampling, a facility would continue to use the highest sulfur content from previous 30 daily samples, and the actual density and GCV. For continuous oil sampling with an automatic sampler, a facility would continue to use the actual sulfur content, density, and GCV. For the two new methods of manual sampling, EPA considered whether conservative or actual values should be used to calculate emissions and heat input. EPA also considered whether the same type of calculational value should be used for sulfur content, density, and GCV. For example, if conservative sulfur content and density values are used to calculate the SO_2 mass emission rate, should a conservative or an actual measured GCV be used to calculate the heat input rate?

For manual samples taken from a storage tank at a plant whenever fuel is added to the tank, EPA considered the following options: (1) using the highest sulfur content and density from the previous three samples, and the actual GCV, (2) using the highest sulfur content from the previous three samples, and the actual density and GCV, (3) using the actual sulfur content, density, and GCV, (4) using the highest sulfur content, density, and GCV from the previous calendar year, and (5) using the maximum sulfur content, density, and GCV allowed by fuel purchase contract with the fuel supplier. The third, fourth, and fifth options are incorporated into today's proposal in section 2.2.4.2. Under this approach, a facility would take a sample from the storage tank whenever fuel is added to the tank. No blending of fuel would be allowed from the time the oil is sampled until the fuel is combusted by the unit. The sample would be analyzed for sulfur content, density, and GCV. Based on the selected option (3, 4, or 5), the appropriate values would then be used to calculate the SO_2 mass emission rate and the heat input rate from the date and hour in which the transfer of oil is complete until the date and hour when oil is again added to the tank.

EPA considered several different options for the case where a facility or its supplier would sample each oil delivery (or the supplier's storage tank) before the fuel is transferred into a tank at the plant. EPA considered whether or not these values needed to be conservative and concluded that there was a real possibility of underestimating SO_2 emissions by using the fuel analysis values from a delivery. The options that EPA considered to avoid the underestimation were: (1) using the highest sulfur content and density from all samples taken from oil combusted during the previous 30 days, and the actual GCV, (2) using the maximum sulfur content, density, and GCV in the fuel purchase contract specifications, (3) using the highest sulfur content, density, and GCV from a sample taken in the previous calendar year, and (4) using the highest sulfur content, density, and GCV ever recorded for the unit. The second and third options are incorporated into today's proposed rule in section 2.2.4.3 of Appendix D.

Under the selected options, a facility or its supplier would need to sample a delivery of fuel before it is transferred into a storage tank. The facility would then need to keep records of the fuel analytical results for three years. The facility would use the conservative value it selected under option (2) or (3), above, in order to calculate the SO_2 mass emission rate and the heat input rate. If an as-delivered sample were ever analyzed and found to have a sulfur content, density, or GCV that exceeded the value being used in calculations (i.e., the contract specification, or the maximum value measured in the previous calendar year), then the new sampled value would be used to calculate the SO_2 mass emission rate or the heat input rate, as follows. For a unit using a default value of the maximum value measured during the previous calendar year, that new sample value would become the new default value and would be reported for the remainder of the current year and the next year, unless superseded by a higher sampled value. For a unit using a default value of a contract specification, the new sample value would continue to be used as the new default value instead of the contract specification value, unless superseded by a higher sampled value or by a new contract.

Rationale

EPA considers continuous sampling and the measurement of fuel from a storage tank at a plant after each addition of fuel to the tank to be highly accurate methods that will be representative of the fuel combusted in a unit. However, if samples are taken from the truck or barge used to ship the fuel, or if samples are taken ''as-delivered,'' the sample values will not necessarily accurately reflect the oil being combusted by the unit at any particular time (see Docket A–97–35, Item II–E–22). For example, a storage tank could contain oil with an average sulfur content of 0.6 percent. Then a new delivery with a sulfur content of 0.4 percent is received and transferred to the tank. The ''as-delivered'' sample value from the delivery truck would underestimate the emissions at that time, since the fuel actually combusted will combine a mixture of the old fuel supply in the storage tank and the new fuel that is added. Thus, a more conservative sulfur value should be used to calculate SO_2 emissions if samples are taken from the delivery containers or from a container used by the oil supplier.

For density and GCV, today's proposal, at the suggestion of some industry representatives, uses conservative values determined by the same method for both parameters (see Docket A–97–35, Item II–E–24). This has the advantage of being easy to remember and to program. However, if greater accuracy is desired, a facility would always have the option of using actual sulfur content, density, and GCVs if it took samples from its storage tank after each addition of fuel to the tank, or if it took continuous, automatic samples.

EPA considered which conservative values would be appropriate for sulfur, density, and GCV. EPA at first considered using the maximum value from all oil supplies combusted in the previous 30 days. This is similar to the current wording of section 2.2.1.2 of Appendix D for calculation of SO_2 emissions from diesel fuel as-delivered sampling. However, in the process of implementing this provision of part 75, EPA found this wording was somewhat confusing and issued policy guidance to clarify section 2.2.1.2 of Appendix D (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.9). This policy essentially directs facilities to keep track of the amount of fuel used as well as its sulfur content. Because of the more complicated nature of this accounting, some industry representatives suggested that it would be simpler to use a conservative default value that would not require tracking fuel usage (see Docket A–97–35, Item II–E–24). Of the default values considered, EPA felt that the most appropriate default values would be the maximum values established by agreement with the fuel supplier through a contract or the maximum measured value from all samples in the previous calendar year. Contractual limits should be higher than or equal to the actual sulfur content, density, or GCV. Because not all units would necessarily have a fuel contract limiting oil sulfur content, density, or GCV, EPA is also proposing to provide the option of using the maximum oil sulfur content, density, or GCV in the previous calendar year.

The Agency also considered whether the current provisions of 2.2.4 of Appendix D should be retained for calculation of SO_2 emissions using the highest sulfur from the previous 30 daily samples when performing daily manual sampling. As discussed above in Section III.P.2(a) of this preamble on oil sampling frequency, the Agency is proposing to retain the option as requested by at least one utility representative.

(b) *Gaseous Fuels.*

Background

The vast majority of Acid Rain units which burn gaseous fuels combust pipeline natural gas. Section 2.3.2 of Appendix D contains a provision for calculation of SO_2 mass emissions from pipeline natural gas using a default SO_2 emission rate in lb/mmBtu and the heat input rate of pipeline natural gas. However, if a facility or its supplier is sampling gaseous fuel for sulfur content, either because it is not pipeline natural gas or because the facility chooses to use a sampled value, then Appendix D requires the facility to calculate the SO_2 mass emission rate using the sulfur content of the sample and the volume of gas combusted, and to calculate the heat input using the GCV of the sample and the volume of gas combusted (see Equations D–5 and F–20). Because of the nature of gaseous fuels, they are always measured with a volumetric fuel flowmeter. The formulas for calculating the SO_2 mass emission rate and the heat input rate use volume directly and do not require information on gas density. The current provisions of Appendix D allow a facility to calculate the SO_2 mass emission rate and the heat input rate using the actual value from a daily sample of gaseous fuel.

When the provisions of section 2.3 of Appendix D were added to part 75 in the May 17, 1995 direct final rule, EPA presumed that virtually every utility combusting gaseous fuel was combusting pipeline natural gas. However, the Agency found that utilities were combusting other types of gaseous fuels. One utility submitted a monitoring plan and a certification application for fuel flowmeter monitoring systems that indicated the utility was also using propane liquefied petroleum gas (LPG) (see Docket A–97–35, Item II–D–6). The utility indicated that it wished to use the default emission rate factor reserved for pipeline natural gas in its monitoring plan and later petitioned the Agency specifically for permission to use the default emission rate factor of 0.0006 lb/mmBtu. In conversations with utility staff, EPA found that the utility wanted to avoid the expense of additional daily samples and the trouble of entering daily sulfur values manually into its data acquisition and handling system (see Docket A–97–35, Items II–E–11, II–E–20). The Agency eventually approved a revised petition for the utility that allowed the utility to take propane samples from each discrete delivery, rather than on a daily basis, where the utility calculates sulfur dioxide emissions from propane by using the highest sulfur content recorded during the previous 365 days and reports these data in its quarterly electronic data report (see Docket A–97–35, Items II–C–14 and II–D–22).

The Agency found that there were also some utilities burning gaseous fuels that were by-products of an industrial process (see Docket A–94–16, Item II–D–71). EPA had concerns that such ‘‘digester gas’’ might have a more variable sulfur content than pipeline natural gas, since the gaseous fuel would begin with a higher sulfur content than pipeline natural gas and would not necessarily go through a process that would reduce and stabilize the sulfur content.

Discussion of Proposed Changes

In today’s proposed rule, the provisions for sampling gaseous fuels are found in section 2.3.1 of Appendix D. For gaseous fuels that are delivered in discrete lots, a facility would use conservative values for sulfur content and GCV to calculate the SO_2 mass emission rate and the heat input rate. For the sulfur content value, the highest sampled sulfur content from the previous calendar year or the maximum value allowed by contract would be used to calculate the SO_2 mass emission rate. For GCV, the highest of all sampled values in the previous calendar year or the maximum value allowed by contract would be used to calculate the heat input rate. If, for any gas sample, the assumed sulfur content or GCV were exceeded, the sampled value would become the new assumed value. For units using the contract value, the sampled value would continue to be used unless a new (higher) contract specification were put in place or unless an even higher sampled value is obtained. For units using the maximum value from the previous year, the sampled value would continue to be used for the remainder of the current year and for the next calendar year unless it was superseded by an even higher sampled value.

For any gaseous fuel where daily fuel sampling is required, a facility would use the highest sulfur in the previous 30 daily samples. For gaseous fuels other than pipeline natural gas, where daily sampling of sulfur content is required, the highest GCV from the previous 30 daily samples would be used. For pipeline natural gas, where monthly sampling of GCV only is required, the actual measured GCV, the highest of all sampled values in the previous calendar year, or the maximum value allowed by contract would be used.

For a gaseous fuel that is not produced in batches and that has a relatively high sulfur content and a high sulfur variability, continuous sampling with a gas chromatograph would be required. Sulfur content would be reported as actual measured hourly average values. The GCV would also be determined on an hourly basis, or, alternatively, the highest value in the previous 30 unit operating days could be reported.

Rationale

For gaseous fuel supplied in discrete deliveries, EPA is proposing to take the same approach as for fuel oil that is being delivered to a plant by barge or truck. EPA has already approved this approach with one utility that combusts liquefied petroleum gas (see Docket A–97–35, Items II–C–14 and II–D–22). Because a discrete delivery of gaseous fuel would be maintained in an enclosed chamber with a relatively constant temperature and pressure, one would expect the gaseous fuel to behave like an ideal gas. Thus, sulfur and other constituents of the fuel should be evenly distributed throughout the delivery of fuel. Using conservative values to calculate the SO_2 mass emission rate and the heat input rate should account for any variability between deliveries. Furthermore, this reduces the number of changes that would be made to a data acquisition and handling system to add fuel supply data.

For gaseous fuel other than pipeline natural gas, where daily fuel sampling is required, EPA considered leaving unchanged the current provisions of section 2.3.1 of Appendix D that would allow a utility to use the actual value from a day's sample to calculate the SO_2 mass emission rate and the heat input rate. However, the Agency believes that it is appropriate to change the sulfur content value to be a somewhat conservative historical value. This is because the Agency has concerns that there may be some gaseous fuels other than natural gas, such as digester gas, that may have significant variability in their sulfur content over the course of a day or a longer period of time. This might result in the underestimation of the SO_2 mass emission rate.

In the case of fuel oil, some industry representatives suggested it was simplest to determine the appropriate conservative values for sulfur content, density, and GCV by the same method (see Docket A–97–35, Item II–E–24). With one exception (for fuels with relatively high sulfur content and high sulfur variability), today's proposal follows this suggestion for gaseous fuels. The proposal uses the highest sulfur content and the highest GCV from the previous 30 daily samples. This is currently the procedure used to determine the sulfur value used in calculations from daily manual oil samples. Since this algorithm for daily manual oil sample calculations is already being used by many software programmers, it is a good conservative value to use for daily samples in this case. The Agency notes that currently, the heat input is calculated using the actual sampled GCV and that this change would require software reprogramming for units where gaseous fuel is sampled daily. However, for pipeline natural gas that is sampled monthly for GCV, facilities could continue to use the actual GCV measured in a monthly sample. The other two options are more conservative and would require software changes. The Agency requests comment on the proposal to use the more conservative GCV value to determine the heat input rate for gas combustion when gaseous fuel is sampled daily (which differs from the current procedure in section 2.3.1.3 of Appendix D and section 5.5.2 of Appendix F).

For gaseous fuel that has a relatively high sulfur content and high sulfur variability, daily sampling is not considered adequate to ensure that SO_2 emissions will not be underestimated. Therefore, for such fuels, continuous sampling with a gas chromatograph and hourly reporting of sulfur content would be required. For GCV, which is expected to be less variable than sulfur content, either the actual hourly measured value or the highest GCV value obtained in the last 30 unit operating days could be reported.

4. Missing Data Procedures for Sulfur, Density, and Gross Calorific Value

Background

(a) *Fuel Oil.* The May 17, 1995 direct final rule included missing data procedures for missing analytical information on sulfur content, density, and GCV in section 2.4 of Appendix D. These procedures are based on a daily sampling frequency. For example, missing sulfur content, density, or GCV data are to be calculated using the highest measured sulfur content, oil density, or GCV during the previous thirty days when the unit burned oil. This was intended to mean that the substitute data values are to be based on the previous thirty daily oil samples for which data are available.

In order to ensure that a DAHS is capable of implementing the missing data procedures required by the rule, § 75.20(c)(7) and § 75.20(g)(1)(ii) require testing of each DAHS. EPA issued policy guidance discussing how facilities should report the results of these tests for units measured with fuel flowmeters. This policy guidance provided a form checklist that facilities could use to show the results of their own tests of the missing data substitution procedures (see Docket A–97–35, Item II–I–9, Policy Manual, Question 15.9). Some utilities objected to testing the DAHS missing data procedures on the grounds that they should never miss sample data. In part, this would be because the facility is required, under section 2.2.5 of Appendix D, to split its sample and keep a portion. One utility offered to substitute the maximum potential sulfur content, which would require less complicated DAHS programming than using the maximum sulfur content of the previous 30 daily samples.

(b) *Gaseous Fuels.* Section 2.4.1 of Appendix D, as revised by the May 17, 1995 direct final rule, provides missing data substitution procedures for missing sulfur data from daily samples of gaseous fuel. The DAHS is required to substitute the highest measured sulfur content recorded during the previous 30 days when the unit combusted gaseous fuel. As for oil, this was intended to be the highest sulfur value from the previous 30 daily samples with available sulfur values. Section 2.4.2 of Appendix D requires the substitution of the highest measured GCV recorded during the previous three months that the unit burned gaseous fuel when data are missing from a monthly gaseous fuel sample. As for fuel oil, the missing data procedures for gaseous fuels are linked to the frequency of fuel sampling.

A utility indicated to EPA that because it receives gas sampling information from its supplier, it should never have missing data for GCV. The utility suggested that it should not have to go to the expense of programming its DAHS for missing data procedures that should never need to be used. This argument was similar to that used by another utility when referring to missing data procedures for manual samples of fuel oil taken upon each delivery.

Discussion of Proposed Changes

EPA proposes to revise the missing data substitution procedures for both fuel oil and gaseous fuel, in order to simplify them. For any instance in which the sulfur content, GCV, or density value is missing, the maximum potential value would be reported until the results of a subsequent valid sulfur content analysis, GCV determination, or density measurement are obtained. The proposed appropriate maximum potential values are specified in the table below. The default values for sulfur content, GCV, and density of residual oil and diesel fuel were taken from handbook values (see Docket A–97–35, Item II–A–7). The default maximum sulfur content values for gaseous fuel are consistent with the maximum sulfur content allowed under the definition of natural gas and the *de facto* maximum sulfur content of pipeline natural gas, based on the proposed definition. Thus, any gas with a sulfur content that did not allow it to qualify as pipeline natural gas (i.e., greater than 0.30 gr/100 scf) but still allowed it to be measured following Appendix D procedures (i.e., total sulfur content not exceeding 20.0 gr/100 scf) would have a default maximum potential sulfur content of 20.0 gr/100 scf. The default values for GCV of gaseous fuels were taken from handbook values (see Docket A–97–35, Item II–I–1). For pipeline natural gas, it is assumed that the gas is primarily methane (GCV of 1050 Btu/scf) with a small amount of other hydrocarbons with a higher GCV (see Docket A–97–35, Item II–E–19). For other gaseous fuels, it is assumed that they are primarily butane (GCV of 2100 Btu/scf), the hydrocarbon gas with the highest GCV of gases commercially used for fuel.

MAXIMUM POTENTIAL DEFAULT VALUES FOR SULFUR CONTENT, DENSITY, AND GCV DATA

Parameter	Fuel	Maximum potential default value
Sulfur content	residual oil	3.5 percent by weight.
	diesel fuel	1.0 percent by weight.
	pipeline natural gas	0.30 gr/100 scf.
	gaseous fuels with sulfur content greater than pipeline natural gas.	20.0 gr/100 scf.
GCV/heat content	residual oil	19,500 Btu/lb.
	diesel fuel	20,000 Btu/lb.
	pipeline natural gas	1100 Btu/scf.
	gaseous fuels with sulfur content greater than pipeline natural gas.	2100 Btu/scf.
Oil Density	residual oil	8.5 lb/gal,
	diesel fuel	7.4 lb/gal.

Rationale

(a) *Fuel Oil.* It seems possible that a facility might occasionally miss a sample taken with an automatic sampler, and thus, would have missing data. Therefore, today's proposal includes a provision for substitution of missing sulfur content, density, and GCV data from continuous, automatic sampling.

Based upon comments from some utilities, it seems relatively unlikely that both a facility and its supplier would miss performing a sample during a delivery. Both a facility and its fuel supplier will want to verify that the fuel delivered is actually supplying the heat content that it is supposed to, either under a contract or a fuel specification; thus, both a facility and its fuel supplier will have an incentive to ensure sampling takes place for a delivery. Furthermore, if samples taken by a facility are split, then there should generally be the ability to provide analytical data for that fuel, even if test results were somehow lost. Because the event of missing fuel samples is unlikely for as-delivered samples, EPA believes that it would be appropriate to establish a simple, conservative value that could easily be substituted in a data acquisition and handling system. This would be easier to program than using historical values that require tracking fuel usage over an extended period of time.

EPA is specifically proposing the most conservative (maximum potential) values for missing data purposes. This would ensure that substituted missing data values would be less advantageous to a facility than taking samples and using sulfur content, density, and GCV data from samples. In addition, several utilities suggested to EPA that this was a reasonable approach (see Docket A–97–35, Item II–E–24).

(b) *Gaseous Fuels.* As mentioned previously, gas sampling is generally performed by fuel suppliers because of the difficulty and potential danger of opening up a pressurized pipe containing a highly flammable gas. It seems extremely unlikely that a fuel supplier would not have information available on the sulfur content or GCV of gaseous fuel, since industrial customers will purchase fuel or agree to a contract based upon these characteristics. The exception to this might be gaseous fuel manufactured through an industrial process that is not produced specifically for sale as a fuel, such as digester gas. In today's proposed rule, EPA is using the same reasoning as above for missing manual fuel oil sample data and is using the same basic substitution approach for missing sulfur content and GCV data for gaseous fuel.

EPA considered keeping the existing missing data substitution procedures from sections 2.4.1 and 2.4.2 of Appendix D for missing data from gaseous fuel. This would have the advantage of requiring no reprogramming of software for facilities already following the existing procedures. EPA also considered using the maximum sulfur content or GCV from the previous calendar year, the same procedure proposed in today's rule for calculation of SO_2 mass emission rate or heat input, for discrete deliveries of gas or for manual samples of oil taken from a delivery truck or barge. However, using the proposed maximum value would require little reprogramming and would greatly simplify the missing data procedures. In policy guidance, the Agency has indicated it would accept a simplified DAHS for units using the procedures of Appendices D and E. In particular, these policies endorse manual entry of fuel analytical data, simplified missing data procedures for fuel flowmeters, and a DAHS that uses commercial spreadsheet software instead of a specialized custom software for purposes of part 75 (see Docket A–97–35, Item II–I–9, Policy Manual, Questions 14.72 and 14.73). In keeping with the policy of allowing Appendices D and E units to use commercial spreadsheet software, EPA has proposed what it believes to be the simplest possible missing data substitution procedure for missing sulfur content and GCV data. In addition, using the proposed maximum potential sulfur content or GCV would ensure that substituted missing data values are more conservative than the values normally used to calculate the SO_2 mass emission rate and the heat input rate.

5. Installation of Fuel Flowmeters for Recirculation

Background

The current provisions of section 2.1.1 of Appendix D require the use of an additional ''return'' fuel flowmeter when some fuel is recirculated, i.e., initially sent toward a unit and then diverted away from the unit without being burned. This additional fuel flowmeter is required, regardless of the amount of fuel being diverted.

At least one utility has requested to use only the fuel flowmeter measuring fuel leaving the oil tank without a second fuel flowmeter to measure any fuel diverted away by the recirculation fuel line. The utility argued that using a single fuel flowmeter would result only in the overestimation of SO_2 emissions, since the utility would measure a larger amount of fuel usage. This would allow the facility to avoid the expense of installation, certification, and quality assurance testing on a fuel flowmeter on the recirculation fuel line. Since the proportion of fuel being recirculated was minimal, the utility was willing to use a more conservative SO_2 emissions calculation in exchange for devoting fewer resources for the testing and maintenance of the recirculation line fuel flowmeter.

Discussion of Proposed Changes

In today's proposal, EPA proposes to allow facilities to use only a fuel flowmeter on the main fuel line from the oil tank if the amount of oil recirculated is demonstrated to be less than 5.0 percent of total fuel usage for each hour during the year.

Rationale

EPA believes that it is reasonable not to require installation, certification and quality assurance of secondary fuel flowmeters in cases where the amount of fuel to be combusted is a small proportion of the total fuel used, and where knowing the exact volume of the recirculated fuel makes little difference in the calculation of emissions and heat input. EPA has allowed one utility to use an estimate of the maximum oil usage at start-up, rather than requiring the utility to install a return line oil flowmeter to measure the startup fuel flow rate.

At first, EPA considered making the installation of a fuel flowmeter on a recirculation fuel line optional. Presumably, if the cost in lost SO_2 allowances were greater than the cost of installing and maintaining a fuel flowmeter, then a facility would choose to use a fuel flowmeter on the recirculation fuel line. However, many fuel flowmeters used under Appendix D for determining the SO_2 mass emission rate and the heat input rate are also used to estimate the NO_X emission rate in lb/mmBtu under Appendix E to part 75. The Appendix E procedures estimate hourly NO_X emission rates using a correlation between measured NO_X emission rates and heat input rates. The correlation is established during a testing period. Therefore, subsequent to the test period, if the hourly heat input values should become less accurate, it could result in the estimated NO_X emission rates becoming less accurate. Such loss in accuracy could occur if the heat input rates during the initial testing period were based upon subtraction of measured volumes or masses of recirculated fuel from the total fuel flow rates, and then the facility later began estimating, rather than measuring, the recirculated fuel volumes or masses. The potential inaccuracy would increase if the proportion of recirculated oil to the total flow rate of oil varies over time. The NO_X emission rate can sometimes increase with increases in the heat input rate and can sometimes decrease with increases in the heat input rate, depending on the particular type of boiler; in addition, when certain types of control equipment are installed, the NO_X emission rate may not have any relationship with the heat input. Thus, an overestimation of the heat input rate would sometimes result in the overestimation and sometimes result in the underestimation of the NO_X emission rate under Appendix E. For these reasons, EPA believes that there needs to be some limits on the cases where a facility can choose not to use a return fuel flowmeter.

In today's proposed rule, EPA is proposing that a facility may choose to use only a fuel flowmeter on the main fuel line from the oil tank and not install a return meter in those cases where the previously measured proportion of oil from the recirculation line is less than or equal to 5.0 percent of the unit's total oil usage during each hour of the year. EPA believes that an error of 5.0 percent in the heat input rate should be small enough that it will not significantly affect accounting for the NO_X emission rate under Appendix E. An analysis of emissions data from a gas-fired Appendix E unit with a higher than average NO_X emission rate for gas (0.157 lb/mmBtu) showed that a 5.0 percent increase in heat input would change the quarterly average NO_X emission rate by only 3.17 percent (0.152 vs. 0.157 lb/mmBtu) (see Docket A–97–35, Item II–B–19). At the same time, EPA believes that an average proportion of 5.0 percent of total fuel usage should provide relief for the most extreme situations where it might cost more to perform quality assurance testing on a return fuel flowmeter than the value of the allowances saved by monitoring with the return flowmeter.

The Agency also considered whether it would be more appropriate to determine the proportion of recirculated fuel on an hourly average basis or on an annual average basis to determine if the returned fuel was less than 5.0 percent of total fuel usage. The Agency concluded that the proportion of fuel could be determined only if a return fuel flowmeter were already installed on the recirculation fuel line. Thus, there would appear to be little advantage to basing the proportion of fuel on an annual basis. Hourly average fuel flow rate would also be more directly related to the heat input rate used to calculate hourly NO_X emission rate under Appendix E. EPA notes this is not fully consistent with the objective of revising this provision, i.e., to exempt facilities from installation and operation of additional fuel flowmeters. Therefore, the Agency believes it is better to base the reduced fuel flow rate monitoring requirement either on actual historical fuel flowmeter data or on some other method, as yet unknown, that would yield a reasonable estimate of the average proportion of fuel recirculated to the total amount of fuel used. At this time, the Agency is unaware of what other methods could provide a reasonable estimate of the average proportion of fuel recirculated to the total amount of fuel used, either on an hourly or an annual basis. Accordingly, the Agency would allow facilities to suggest methods through the petitioning process of § 75.66.

6. Fuel Flowmeter Testing

(a) *Fuel Flowmeter Accuracy Tests.*

Background

Sections 2.1.5 and 2.1.6 of Appendix D, as revised by the May 17, 1995 direct final rule, refer to calibration and recalibration of fuel flowmeters. Section 2.1.5.2 gives procedures for a test of the flowmeter accuracy by comparing a candidate flowmeter against another flowmeter that has already been calibrated according to specified procedures. If a flowmeter does not meet the specified accuracy, then it would need to be recalibrated by adjusting it, then retested to ensure it is reading accurately.

Some utilities have found confusing the terminology of ''calibration'' for a test that compares measurements from two different flowmeters. Generally, the term ''calibration'' is used to refer to adjustments made to a flowmeter to ensure it is reading accurately. However, the type of test described in section 2.1.5.2 is more like a relative accuracy test audit than a calibration, in that it checks the flowmeter accuracy by comparing the fuel flowmeter readings against readings from an outside standard.

Discussion of Proposed Changes

To alleviate the confusion surrounding flowmeter testing, today's proposal introduces the term ''flowmeter accuracy test.'' This terminology is used in sections 2.1.5 and 2.1.6 of Appendix D.

Rationale

EPA believes that the term ''flowmeter accuracy test'' more clearly reflects the nature of the test that is performed. Introducing this new term also will clarify that the word ''calibration'' refers to flowmeter adjustments, rather than to a comparative test between a candidate flowmeter and a reference meter.

(b) *Methods for Fuel Flowmeter Accuracy Testing.*

Background

Section 2.1.5.1 of Appendix D, as revised by the May 17, 1995 direct final rule, includes a list of standards and procedures that may be used to determine if a flowmeter is sufficiently accurate for use under the Acid Rain Program. However, because of the large number of different brands and kinds of fuel flowmeters, there are also many manufacturers' procedures that are not explicitly permitted under part 75. Consequently, many Acid Rain certification applications for units with fuel flowmeters have contained petitions under §§ 75.23 and 75.66 for approval of other fuel flowmeter testing procedures. Among those methods was AGA Report No. 7 for turbine flowmeters. This method was incorporated by reference into part 75 in the November 20, 1996 final rule. In addition, another standard method that EPA approved through petitions is American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the *Manual of Petroleum Measurement Standards,* October 1988 edition (see reproduction of this document in Docket A–97–35, Item II–D–10 (Attachment B)).

In the process of implementing part 75, many utilities have commented on the problems of testing and calibrating fuel flowmeters. Unlike CEMS or stack flow monitors, it is not always possible to perform an accuracy test with the fuel flowmeter remaining in the pipe where it is installed. Utilities have stated that certain fuel flowmeters are extremely difficult to remove, send out for testing, recalibrate, and then reinstall (see Docket A–97–35, Item II–E–22). In addition, removing a fuel flowmeter from in-line may require stopping flow of the fuel and possibly shutting down the unit, with negative economic consequences (see Docket A–97–35, Item II–E–8). In addition, if a facility needs to operate a unit while the flowmeter is being tested at a laboratory, then no flow data will be available for the fuel measured by the flowmeter unless the facility has a backup fuel flowmeter. Utilities have petitioned for alternative quality assurance procedures for fuel flowmeters in order to avoid the inconvenience and expense of removing the fuel flowmeter and testing it (see Docket A–97–35, Item II–D–9). Because of this, the Agency has been evaluating various ways of testing a fuel flowmeter in-line (that is, still installed in the pipe in its regular position).

Some utilities have suggested that an alternative way to check fuel flowmeter accuracy would be to compare over time the ratio of the fuel flowrate to unit output (''load''), measured either in electrical generation in MWe or in steam flow in 1000 lb/hr (see Docket A–97–35, Item II–E–21). A fuel flow-to-load comparison could be used to determine if fuel flowmeter readings are still similar to the readings obtained the last time the fuel flowmeter was tested against an outside method. A significant change in the amount of fuel used at a load level would call into question the validity of fuel flow readings from a flowmeter. A fuel flow-to-load comparison could provide this check without removal of the fuel flowmeter from its installed location, which would be of considerable benefit to facilities.

Discussion of Proposed Changes

EPA is proposing to incorporate by reference the standard: American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the *Manual of Petroleum Measurement Standards.* The Agency also specifically requests comment on any other voluntary consensus standards from standard setting organizations, such as API, AGA, ASME, or ISO, that would be appropriate for incorporation by reference into part 75. Any suggested methods should also be submitted to the Agency as part of the comments to assist in the Agency's evaluation.

Section 2.1.7 of Appendix D to today's proposed rule includes provisions for an optional, supplemental quality assurance test for fuel flowmeters using a ratio of the fuel flow rate and the unit load. The fuel flow rate-to-load ratio comparison test would provide an additional way to meet the requirement to periodically test fuel flowmeter accuracy. This test would serve as a supplement to more rigorous fuel flowmeter tests. These more rigorous tests include the standards incorporated by reference under section 2.1.5.1 of Appendix D that require the fuel flowmeter to be taken out of line and shipped to a laboratory, and the ''master meter'' comparison procedures under section 2.1.5.2 of Appendix D. For orifice-, nozzle-, and venturi-type flowmeters, the more rigorous tests would include an inspection of the primary element and an accuracy test on the transmitters or transducers. If a facility performed and passed regular quarterly fuel flow-to-load ratio testing, then it would need to perform the more rigorous checks on monitor performance only once every 20 calendar quarters (five years).

The fuel flow-to-load ratio test would require a facility to establish a baseline period from a period of time when the fuel flowmeter is known to be operating properly. After establishing this baseline of accurate fuel flow data (or heat input rate data), a facility would calculate the fuel flow-to-load ratio (or ''gross heat rate'' (GHR)) during the baseline period. In each ''flowmeter operating quarter'' that the fuel flowmeter operates after the baseline period is completed, the facility would calculate the fuel flow-to-load ratio (or GHR) for each hour the fuel flowmeter is used to report data. The facility would compare the hourly fuel flow-to-load ratio (or GHR) to the fuel flow-to-load ratio (or GHR) during the baseline period in order to calculate the absolute value of the percentage difference for each hour. Next, the facility would calculate the average percentage difference for the quarter. If the percentage difference exceeded the specified limits for the test, the fuel flowmeter would fail the test. The key elements of the fuel flow rate-to-load evaluation are discussed in the following paragraphs.

(1) *Use of Gross Heat Rate-to-Load Ratio.* Today's proposed rule would allow a facility the option of calculating either the ratio of the fuel flow rate to the gross generation in MWe or the steam flow rate in thousands of pounds of steam per hour (''fuel flow-to-load ratio'') or the ratio of the heat input rate to the gross generation in MWe or the steam flow rate in thousands of pounds of steam per hour (''GHR''). In order to allow a meaningful comparison, a facility would use one of these two ratios consistently, both in calculating

an initial baseline ratio and in calculating hourly ratios during a particular quarter. Equations D–1c and D–1e describe the calculation of the fuel flow-to-load ratio for the baseline period and for hourly values during a calendar quarter, respectively. For the GHR, the respective equations are Equations D–1d and D-1f. These equations are found in proposed sections 2.1.7.1 and 2.1.7.2 of Appendix D.

(2) *Baseline Period for Fuel Flow-to-Load Ratio.* The provisions for calculating the baseline fuel flow-to-load ratio or gross heat rate are found in section 2.1.7.1 of today's proposed rule. EPA is proposing that the owner or operator of a facility would establish a baseline of fuel flow rate (or heat input rate) data following a flowmeter accuracy test under either section 2.1.5.1 or 2.1.5.2 of Appendix D, or following both a transmitter or transducer accuracy test under section 2.1.6.1 of Appendix D and an inspection of a primary element for an orifice-, nozzle-, or venturi-type fuel flowmeter under section 2.1.6.6. Throughout section 2.1.7 of today's proposed rule, these are referred to as ''the most recent quality assurance procedure(s).'' The baseline period of fuel flow rate (or heat input rate) data for a fuel flowmeter to be tested under section 2.1.7 would use the first 168 hours of quality assured data measured by that flowmeter following the most recent quality assurance procedure(s) for which: (1) only the fuel measured by that fuel flowmeter is combusted (i.e., no co-firing of fuels occurs); (2) the load is relatively stable and not ''ramping'' rapidly up or down; and (3) the load is sufficiently above the minimum safe, stable operating load (unless low-load operation is normal for the unit).

Today's proposal includes a limit to the length of time over which the baseline period could extend. The baseline period of 168 hours could not extend for longer than the end of the second calendar quarter following the calendar quarter in which the most recent quality assurance procedure(s) was performed. For orifice-, nozzle-, and venturi-type fuel flowmeters, two quality assurance procedures would be required: both a transmitter or transducer accuracy test under section 2.1.6.1 of Appendix D and an inspection of a primary element, such as an orifice plate. For practical purposes, this means that the transmitter or transducer accuracy test and the primary element inspection would have to be completed either in the same calendar quarter or in consecutive calendar quarters. If there were not 168 hours of quality-assured fuel flowmeter data from hours when a single fuel is combusted, then the fuel flowmeter would not be allowed to be tested using the fuel flow-to-load ratio as a supplement to other quality assurance tests.

The 168 hours of quality-assured fuel flowmeter data next would be averaged and divided by the average load, in megawatts or 1000 lb steam/hr, during the same 168 hours to determine the baseline fuel flow-to-load ratio (see Equation D–1c). Alternatively, the facility could instead calculate the gross heat rate by averaging hourly heat input rate during the 168 hours of the baseline period and by dividing the average heat input rate by the average load during the same 168 hours (see Equation D–1d).

In cases where the fuel flowmeter is located on a common pipe header, one fuel flow rate measurement could be associated with the load from several units that receive fuel from the common pipe header. In order to analyze the fuel flow-to-load ratio for a flowmeter on a common pipe header, the load from all units receiving fuel from the common pipe header would have to be combined for each hour, averaged over the baseline period of 168 hours, and compared to the average fuel flow rate during the baseline period. If a single unit receives fuel from multiple pipes, each pipe with its own fuel flowmeter, then the flow rates from all fuel flowmeters would have to be added together to obtain the average fuel flowrate for the unit to be divided by the unit load.

(3) *Data Preparation and Analysis.* In each flowmeter operating quarter following the final quarter of the baseline period, all hourly fuel flowmeter data would be compared to the load. A flowmeter operating quarter would be a calendar quarter in which the unit combusts the fuel measured by the fuel flowmeter for at least 168 hours. For each hour in which the fuel is combusted, the owner or operator would calculate the fuel flow-to-load ratio (or GHR) (see Equation D–1e for the fuel flow-to-load ratio and Equation D–1f for the GHR). Hourly fuel flow rates on common pipe headers would be compared to the sum of the loads from all units receiving fuel from the common pipe header. For units with multiple pipes and multiple fuel flowmeters, the total hourly fuel flow rate for the fuel would be compared to the unit load.

Next, the facility would compare the hourly fuel flow-to-load ratios (or GHRs) to the baseline fuel flow-to-load ratio (or GHR). The absolute value of the percentage difference would be calculated for each hour using Equation D–1g. Then the facility would calculate the average value of the percentage difference for the quarter, using each hourly percentage difference in Equation D–1h.

The quarterly average of the hourly percentage difference values next would be compared to the limitation. For either the fuel flow-to-load ratio or the GHR, Ef, the quarterly average of the hourly percentage difference values would need to be no greater than 10.0 percent, unless the average of the hourly loads used for the analysis was ≤ 50 MWe (or ≤ 500 klb/hr of steam), in which case the limit on Ef would be 15.0 percent. If a fuel flowmeter were to fail to meet this limit when using all data in the flowmeter operating quarter, then the facility would have the option of excluding certain hours. Otherwise, a failure to meet the 10.0 percent (or 15.0 percent, if applicable) limit would be considered a failure of the fuel flow-to-load ratio test.

(4) *Optional Data Exclusions.* As mentioned above, if a fuel flowmeter's data would not meet the 10.0 percent (or 15.0 percent, if applicable) limit on the quarterly average of the percentage difference values, then a facility could opt to exclude certain hours of unrepresentative fuel flow rate (or heat input rate) data and then reanalyze the smaller set of data. The types of data that EPA proposes as non-representative would be the same as the hours excluded during the baseline period, including: (1) hours when the unit combusts multiple fuels measured by multiple fuel flowmeters, such as co-firing of gas and residual oil or co-firing of residual oil and diesel fuel; (2) hours when the unit load is rapidly rising or falling, sometimes referred to as ''ramping,'' to such a degree that the load in a given hour differs by more than ± 15.0 percent from the load during either the previous hour or the hour afterwards; or (3) hours in which the unit load is in the lower 10.0 percent of the unit's operating range, unless operation at those low levels is considered normal for the unit. The facility would proceed to analyze the remaining quarterly fuel flow rate or heat input rate values, provided that there are at least 168 hours remaining for the quarter after excluding non-representative hours. If less than 168 representative hours remained after excluding the allowable hours, then a flow-to-load or GHR test would not be required for that flowmeter for that flowmeter operating quarter. If the fuel flowmeter data still failed to meet the 10.0 percent (or 15.0 percent, if applicable) limit on the quarterly average of the percentage difference values after excluding the allowable

hours, the flowmeter would fail the fuel flow-to-load ratio test.

(5) *Consequences of Failing Fuel Flow-to-Load Ratio or GHR Tests.* There would be two primary consequences of failing a fuel flow-to-load ratio or a GHR test. First, the data from the fuel flowmeter would no longer be considered quality-assured. Thus, the facility would need to invalidate data from the fuel flowmeter following the test. Proposed section 2.1.7.4 of Appendix D specifies that the missing data procedures of section 2.4.2 of Appendix D would be used to substitute for the invalid data (unless a different fuel flowmeter is available that has been tested for accuracy and has been demonstrated to meet the accuracy specification), beginning with the first hour the fuel measured by the fuel flowmeter is used during the quarter following the flowmeter operating quarter in which the meter fails the fuel flow-to-load ratio test. Second, in order to establish that the fuel flowmeter is again operating properly and providing quality-assured data, the facility would perform a fuel flowmeter accuracy test according to sections 2.1.5.1 or 2.1.5.2 of Appendix D or, for orifice-, nozzle-, and venturi-type flowmeters, a transmitter or transducer accuracy test according to section 2.1.6.1 of Appendix D. In addition to the transmitter or transducer test, orifice-, nozzle-, and venturi-type fuel flowmeters would need to be further tested following a failed flow-to-load or GHR test in order to ensure that the problem causing the failure of the fuel flow-to-load ratio was a problem with the transmitters or transducers.

Once the orifice-, nozzle-, or venturi-type flowmeter has been recalibrated and passes a transmitter or transducer accuracy test according to section 2.1.6.1 of Appendix D, the facility would perform a shortened version of the fuel flow-to-load ratio test. The shortened version of the test would use six to twelve hours of data following the passed transmitter or transducer accuracy test. If the fuel flowmeter passed the abbreviated fuel flow-to-load ratio test, then its data would be considered valid, beginning with the time and date of the passed transmitter or transducer accuracy test. However, if the fuel flowmeter were to fail the abbreviated fuel flow-to-load ratio test, then it would be necessary for the facility to inspect the primary element for corrosion or damage. Furthermore, data would be considered invalid until the orifice-, nozzle-, or venturi-type fuel flowmeter passes an inspection of the primary element. Although data from the flowmeter would be considered quality-assured after successful completion of all required accuracy testing, visual inspections and diagnostic tests, the baseline would have to be re-established no later than the end of the second flowmeter operating quarter following the quarter in which the quality assurance tests are completed.

Rationale:

EPA is proposing to incorporate by reference the standard: American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the *Manual of Petroleum Measurement Standards,* October 1988 edition. The Agency has already approved this method of fuel flowmeter testing in response to a petition (see Docket A–97–35, Item II-C–6). This is also a standard agreed to by API that is traceable to NIST standards. The Agency has a general policy of approving standards from technically knowledgeable groups such as the Organization for International Standards (ISO), the American Society for Testing and Materials (ASTM), the American Society of Mechanical Engineers (ASME), the American Gas Association (AGA), the Gas Processors Association (GPA), and API. EPA would also be willing to incorporate additional standards by reference if commenters supply a copy for consideration.

The Agency recognizes that it is difficult and sometimes costly to take a fuel flowmeter out from its installation location to be tested (see Docket A–97–35, Item II-E–22). Today's proposed rule would provide the flexibility of an additional approach for testing fuel flowmeters where they are installed. Today's proposal for a fuel flow rate-to-load comparison test would allow facilities to assure the quality of their fuel flow rate data without taking a fuel flowmeter out of line. Several industry representatives suggested that a fuel flow rate-to-load comparison was a useful approach to quality assuring data (see Docket A–97–35, Items II–E–22, II–E–23). Some industry representatives felt that a fuel flow rate-to-load ratio was straightforward and even more representative than a stack flow rate-to-load ratio (see Docket A–97–35, Item II-E–23).

In general, utilities have indicated that the idea of a fuel flow-to-load ratio is an appropriate quality assurance test for fuel flowmeters (see Docket A–97–35, Items II–D–30, II–D–41, II–E–33). Use of the fuel flow-to-load ratio was first suggested to the Agency as an alternative to annual orifice inspections (see Docket A–97–35, Item II–E–22). One utility mentioned that the fuel flow-to-load ratio test would be most useful if it allowed them to stretch the time between transmitter or transducer accuracy tests on orifice-, nozzle-, and venturi-type fuel flowmeters, as well as primary element inspections and fuel flowmeter accuracy tests performed in-line against a ''master meter'' or performed in a laboratory (see Docket A–97–35, Item II–D–49).

Utilities have also indicated that they would prefer the provisions of the fuel flow-to-load ratio test to be as similar as possible to the stack flow-to-load ratio test in today's proposed rule (see Docket A–97–35, Item II–E–33). This would be easier for facilities to comply with because they would need to learn fewer new procedures, they could use the same equations and algorithms in computer software or hand calculations, and they could report information in a similar format. To the extent possible, the Agency has incorporated this suggestion in today's proposed rule. However, because monitoring with fuel flowmeters is not identical to monitoring with stack volumetric flow monitors, there are some differences in the procedures and in the data to be recorded and reported.

Today's proposed rule would allow the quarterly fuel flow-to-load ratio test as an optional supplement to flowmeter accuracy tests under section 2.1.5.1 or 2.1.5.2 of Appendix D, transmitter or transducer accuracy tests under section 2.1.6.1 of Appendix D for orifice-, nozzle-, and venturi-type fuel flowmeters, and visual inspections of the primary element required under section 2.1.6.6 of Appendix D for orifice-, nozzle-and venturi-type fuel flowmeters. These more rigorous fuel flowmeter quality assurance procedures would still be required at least once every 20 calendar quarters (five years), even if the procedures of section 2.1.7 of Appendix D were followed. The Agency has proposed a quarterly fuel flow-to-load ratio test for several reasons: (1) this is consistent with the provisions of the proposed volumetric stack flow-to-load ratio test in today's proposed rule; (2) the test involves examining data more closely when preparing quarterly reports; and (3) a quarterly test allows facilities to find problems in fuel flowmeter data before an entire year has passed. The Agency also considered requiring the fuel flow-to-load ratio to be used more frequently than quarterly, perhaps daily; however, this would require facilities to spend far more time and effort in evaluating data at different times during the quarter than they may do currently, particularly for small, infrequently operated units. In addition, many utilities claim that fuel flowmeters tend to be stable, and therefore little change would be expected over short time periods such as a day (see Docket A–97–35, Item II–E–33).

EPA is proposing that the optional fuel flow-to-load ratio test could serve as a supplement to other quality assurance procedures for fuel flowmeters for up to 20 calendar quarters (five years). EPA is proposing a time period of 20 calendar quarters for the following reasons. First, it is similar to the current provision in section 2.1.5.2 of Appendix D, which allows a reference fuel flowmeter to be accuracy tested as seldom as once in five calendar years if comparison with an in-line ''master'' flowmeter shows less than a 1.0 percent difference in their flow rates. Second, a five-year test cycle offers certain administrative advantages. For instance, fuel flowmeters used to provide heat input data for the heat input-versus-load correlation of Appendix E could be accuracy-tested before each Appendix E test (i.e., once every five years). In addition, a five-year period would ensure that fuel flowmeters are tested by the time the unit's operating permit is renewed. The 20 calendar quarter (five-year) period is consistent with the provisions for reduced three-level flow RATAs for stack flow monitors. The 20 calendar quarter (five-year) period between tests is also consistent with the proposed time between quality assurance tests for fuel flowmeters that are used very infrequently. Repeating the periodic quality assurance procedures for fuel flowmeters at least every five years would catch slow, long-term changes in heat rates mentioned by a facility and would allow a facility to update its baseline data periodically (see Docket A–97–35, Item II–D–49). Finally, allowing the option of a 20 calendar quarter (five-year) period between more rigorous quality assurance procedures would be safer and less costly than annual testing, while, in coordination with quarterly fuel flow-to-load ratio testing, still providing assurance of the quality of the data.

(1) *Use of Gross Heat Rate or Flow-to-Load Ratio.* Today's proposed rule would allow a facility the option of calculating either the ratio of the fuel flow rate to the gross generation in MWe or the steam flow rate in thousands of pounds of steam per hour (''fuel flow-to-load ratio'') or the ratio of the heat input rate to the gross generation in MWe or the steam flow rate in thousands of pounds of steam per hour (''gross heat rate'' or ''GHR''). One utility suggested that, because the load is created based upon a number of factors in addition to the fuel flow rate, such as the gas heat rate (i.e., gross calorific value), a ratio of the heat input to the unit load would be a better test than the ratio of the fuel flow rate to the unit load (see Docket A–97–35, Item II–D–50). In addition, some utilities pointed out that the Agency allows facilities to use either a stack flow-to-load ratio or a heat input-to-load ratio (gross heat rate) as a diagnostic test on stack volumetric flow monitors, through Policy Manual Question 13.15 (see Docket A–97–35, Item II–I–9). The Agency agrees that the heat input-to-load ratio (GHR) is also a technically appropriate check on the performance of fuel flowmeters. Therefore, today's proposal includes options for both the fuel flow-to-load ratio and the GHR.

(2) *Baseline Period for Fuel Flow-to-Load Ratio or GHR.* When using this type of comparison test, it is important to establish a baseline of reliable data to which hourly data can later be compared. For the stack volumetric flow-to-load ratio, the baseline of reliable data consists of data from the reference method for flow, Method 2 of Appendix A to 40 CFR part 60. However, there is no universally applicable test for flowmeters that is performed in-line with a reference method while the unit is operating, parallel to the flow RATA. EPA asked several utilities what could be a source of baseline data to which the fuel flowmeter could later be compared. One utility suggested using fuel flowmeter readings during a time when the unit is operating at a steady load, such as when the unit undergoes Appendix E testing for a NO_X-versus-heat input correlation or when a NO_X CEMS undergoes a normal level RATA (see Docket A–97–35, Item II–D–41). A second utility recommended that the baseline be established just after performing a transmitter calibration, i.e., after performing a quality assurance test on the fuel flowmeter (see Docket A–97–35, Item II–D–49). The Agency believes that using fuel flowmeter data taken immediately following a flowmeter quality assurance test would be most likely to be accurate and representative of proper operation of the fuel flowmeter. Flowmeter quality assurance tests might include any of the methods incorporated by reference in section 2.1.5.1 of Appendix D; meter testing against a certifiable ''master'' meter under section 2.1.5.2 of Appendix D; or transmitter or transducer accuracy testing under section 2.1.6.1 of Appendix D, and inspection of a primary element for an orifice-, nozzle-, or venturi-type fuel flowmeter under section 2.1.6.6 of Appendix D. This approach is proposed in today's rule.

The utilities supporting the idea of using fuel flowmeter data taken immediately after a flowmeter quality assurance test have suggested that it would be important to have a fairly large number of hours in the baseline, on the order of 100 or more, to ensure that the baseline period is representative of typical operation (see Docket A–97–35, Item II–E–33). In today's rule, EPA is proposing to use the first 168 hours of quality assured data measured by that flowmeter for which: (1) only the fuel measured by that fuel flowmeter is combusted; (2) the unit load is not significantly ''ramping'' up or down; and (3) the unit load is safely above the minimum safe, stable load. The Agency believes that a baseline period containing 168 hours of data is sufficiently long to be representative of different unit operating conditions that may occur later. This specific time period is consistent with the minimum number of hours that a unit combusts a fuel before the quarter counts toward the deadline for the next quality assurance test, and with the minimum number of hours that a unit combusts a fuel before a quarter needs to be evaluated using the fuel flow-to-load ratio. Certain hours would be excluded from the baseline (i.e., periods of co-firing, unstable, or low load), because the fuel flow-to-load ratio or GHR would tend to be less reliable during those periods.

Today's proposal would also limit the baseline period so that it may extend no more than two quarters beyond the quarter in which the flowmeter passes its accuracy tests. The Agency has concerns that if the baseline data were to extend longer than this, the performance of the fuel flowmeter might degrade. In order for the baseline data to reflect fuel flow rate data that are most likely to be accurate, the Agency is proposing that the fuel flow rate or heat input rate data used in the baseline period must either be obtained in the calendar quarter in which the quality assurance procedure is performed, or within two calendar quarters after the QA test. The Agency considered limiting the time period to the same calendar quarter as the quality assurance procedure or to one flowmeter operating quarter beyond the QA test. However, because a quality assurance procedure may be conducted at any time during a quarter, it could be difficult for a facility to collect 168 hours of fuel flowmeter data after a quality assurance procedure in the same calendar quarter or even (for infrequently operated units that ramp up and down often) in the next calendar quarter.

For orifice-, nozzle-, and venturi-type fuel flowmeters, two quality assurance procedures would be required prior to collecting the baseline data: (1) a transmitter or transducer accuracy test, and (2) an inspection of a primary element. The Agency considered whether these two quality assurance procedures should be separated and whether the baseline period could simply be based upon a time period after the most recent quality assurance procedure. The Agency believes that the baseline period data would be more reliable if they were taken shortly after completing both quality assurance procedures for orifice-, nozzle-, and venturi-type fuel flowmeters. Using the same time period for both tests simplifies administration of the fuel flow-to-load ratio test. EPA also notes that a unit does not need to be operating in order to perform the tests; thus, it should not be burdensome for a facility to plan to coordinate the two quality assurance procedures.

(3) *Data Preparation and Analysis.* The proposed procedures for data preparation and analysis for the fuel flow-to-load ratio are similar to those for the volumetric stack flow-to-load ratio. Equations of the same form as those for the stack volumetric flow-to-load ratio are used to calculate the hourly fuel flow-to-load ratio, the hourly absolute value of the percentage difference between the baseline fuel flow-to-load ratio and the hourly fuel flow-to-load ratio, and the quarterly average percentage difference. Common pipe headers would be treated in the same way as common stacks. If there were multiple units associated with a single fuel flowmeter or flow monitor, the total load from all units would be summed before the flow rate data are divided by the load data to calculate the flow-to-load ratio. Fuel flowmeters on multiple pipes would be treated in the same way as multiple stacks associated with a single unit. If there are multiple fuel flowmeters or flow monitors associated with a single unit, the flow rates from all fuel flowmeters for the same fuel or all flow monitors would be added together before the flow rate data are divided by the load data to calculate the flow-to-load ratio.

Certain aspects of the volumetric stack flow-to-load ratio test are not the same for the fuel flow-to-load ratio test. For example, the volumetric stack flow-to-load ratio test requires the facility to screen out those hours when the unit operates further than 10.0 percent away from the average load during the most recent normal-load flow RATA. As was discussed previously, there is no equivalent of an in-line flow RATA for fuel flowmeters. EPA does not believe that there is a need to screen out hours for the fuel flow-to-load test when the unit operates at a load somewhat less than or greater than normal. Some facilities have indicated that the fuel flow-to-load ratio or GHR based on fuel flow readings is less variable over different loads than the volumetric stack flow-to-load ratio (see Docket A–97–35, Items II–E–33 and II–D–98). However, preliminary evidence has also indicated that the fuel flow-to-load ratio or GHR can be significantly different at very low operating loads than at other load levels (see Docket A–97–35, Item II–A–5). For this reason, EPA is proposing to allow hours in which the unit load is within the lower 10.0 percent of the range of operation to be excluded from both the baseline data and the quarterly flow-to-load or GHR analysis, unless such low loads are considered normal for the unit.

Another feature of the volumetric stack flow-to-load ratio test that differs from the fuel flow-to-load ratio test is the treatment of bias-adjusted data. Fuel flow rate data are never adjusted for bias. There is no bias test for fuel flowmeters. Bias-adjustment of data is an issue for the volumetric stack flow-to-load ratio test because bias-adjusted data has already been adjusted to make it more consistent with the value of the reference method data. Thus, bias-adjusted volumetric stack flow data must meet a stricter quarterly average percentage difference of 10.0 percent from the reference flow-to-load ratio, whereas the allowable difference is 15.0 percent when unadjusted volumetric stack flow data are used. (See discussion of stack flow-to-load test in Section III.M. of this preamble.) EPA notes that since the same fuel flow meter is used to produce both the baseline data and the quarterly data, the fuel flow-to-load ratio is more closely analogous to the use of bias-adjusted volumetric flow data. Therefore, the limit on the quarterly average percentage difference from baseline for fuel flow rate data should be at least as stringent as that for bias-adjusted volumetric flow data (10.0 percent). Information provided by facilities on the gross heat rate derived from fuel flow rate data have shown less variability than the corresponding stack heat rate (see Docket A–97–35, Item II–D–98). Based upon this information, EPA is proposing a limit of 10.0 percent on E_f, the quarterly average percentage difference from the baseline for the quarterly flow rate-to-load or GHR evaluation. EPA considered whether it would be appropriate to set a different limit for smaller units, as was done for the stack flow-to-load test. Analysis of some preliminary fuel flow-to-load data has shown that for lower loads (e.g., < 50 MWe), the flow-to-load ratio is quite sensitive to small changes in load (see Docket A–97–35, Item II–A–5). This indicates that it would be appropriate to set a higher limit for smaller units. Therefore, today's rule proposes a limit of 15.0 percent on the value of E_f when the quarterly average load used for the data analysis is 50 megawatts or less (or ≤ 500 klb steam per hour). The Agency solicits comment on the 15.0 percent limit for loads less than or equal to 50 megawatts.

(4) *Optional Data Exclusions.* As for volumetric stack flow monitors, if a fuel flowmeter's data would not meet the limit on the percentage deviation from the baseline, then a facility could opt to exclude certain hours of unrepresentative fuel flow rate (or heat input rate) data and then reanalyze the smaller set of data. The hours of data that EPA proposes to view as non-representative for fuel flowmeters are: (1) hours when the unit combusts multiple fuels; (2) hours when the unit load in a given hour would differ by more than ± 15.0 percent from the load during either the previous hour or the subsequent hour; or (3) hours when the load is very close to the minimum safe, stable load (unless operation in that range is normal).

The baseline period for fuel flowmeters and the data used for the quarterly flow-to-load or GHR analyses would include only those hours when a single fuel is combusted—the fuel measured by the fuel flowmeter. If the quarterly fuel flow rate data included hours when multiple fuels are co-fired, the fuel flow-to-load ratio or GHR for the fuel flowmeter being tested would be biased low. This could result in a failure of the flow-to-load test or GHR evaluation. Today's proposed rule would also allow a facility to exclude from the baseline data and the quarterly analyses those hours that are not representative because the unit's load is changing rapidly. Specifically, hours could be excluded when the unit load in a given hour would differ by more than ± 15.0 percent from the load during either the previous hour or the hour afterwards. There will be a lag in the time between when electricity is generated and registered as load and the time that the fuel flowmeter measures the fuel that is combusted to generate the load. Therefore, during an hour when the load changes rapidly, the fuel flow rate will not necessarily be changing by the same amount or in the same direction. At least one utility has suggested that the Agency consider such an exclusion for the proposed fuel flow-to-load ratio test (see Docket A–97–35, Item II–D–41).

In general, the fuel flow is directly proportional to load, with a linear graphical relationship. However, this is not always the case at extremely low loads (see Docket A–97–35, Items II–E–33, II–D–98). Therefore, today's proposed rule would allow certain low-load hours to be excluded from the flow-to-load baseline and quarterly data analyses. Specifically, loads in the lower 10.0 percent of the ''range of operation'' of the unit, (as that term is defined in proposed section 6.5.2.1 of Appendix A in today's proposal) could be excluded, unless such loads are considered normal for the unit.

Today's proposed rule, in section 2.1.7 of Appendix D, would also exempt a fuel flowmeter from the fuel flow-to-load ratio test in a quarter when a more rigorous quality assurance test is performed. This is unlike the volumetric stack flow-to-load ratio, which is required each QA operating quarter, including quarters when the flow monitor is tested with a RATA (provided, of course, that sufficient data for the analysis are obtained after the RATA).

(5) *Consequences of Failing the Fuel Flow-to-Load Ratio Test.* The consequences of failing the fuel flow-to-load ratio test would be similar to the consequences of failing quality assurance tests in general for fuel flowmeters. Data from the fuel flowmeter would no longer be considered quality assured. Because the fuel flow-to-load ratio test is only performed at the end of a quarter, the facility would invalidate data from the fuel flowmeter beginning with the first hour in the quarter after the quarter in which the meter fails the fuel flow-to-load ratio test. In order to establish that the fuel flowmeter is operating properly and providing quality assured data again, the facility would perform a flowmeter accuracy test or (for orifice-, nozzle-, and venturi-type flowmeters) a transmitter or transducer accuracy test. The Agency believes it is appropriate to perform an accuracy test if the fuel flow-to-load ratio test is failed, because in such cases the facility has had the benefit of postponing the accuracy test based upon the assumption that the fuel flowmeter has continued to measure accurately and consistently with its operation during the baseline period.

Note that for orifice-, nozzle-, and venturi-type fuel flowmeters, a transmitter/transducer test alone would not suffice to demonstrate that the flowmeter is back in control. The owner or operator would still need to ensure that the cause of the failed fuel flow-to-load ratio test was a problem with the transmitters or transducers rather than a problem with the primary element. Sudden changes in flowmeter performance are likely to be caused by a problem with transmitters (see Docket A–97–35, Item II–D–33). However, it cannot be assumed that the transmitters are solely responsible for degradation in monitor performance. In order to verify that the primary element is not contributing additional error to the fuel flow measurements because of corrosion, a facility would conduct an abbreviated (6 to 12 hour) version of the fuel flow-to-load ratio test, similar to the diagnostic test for volumetric stack flow monitors in Policy Manual Question 13.15 (see Docket A–97–35, Item II–I–9). The Agency believes that this abbreviated fuel flow-to-load ratio test would provide additional assurance that the fuel flowmeter is indeed operating properly. In addition, it would be more timely than waiting for another calendar quarter to pass to repeat the fuel flow-to-load ratio. The abbreviated test would also be less burdensome than removing the primary element from the fuel pipe. EPA believes the abbreviated fuel flow-to-load ratio test strikes a reasonable balance by providing some additional quality assurance in a timely manner. If the orifice-, nozzle-, or venturi-type fuel flowmeter failed the abbreviated fuel flow-to-load ratio test, then it would appear that the primary element may also have a problem. Therefore, upon failure of an abbreviated fuel flow-to-load ratio test, the facility would be required to inspect the primary element and to repair or replace it, as necessary.

The rules for data validation upon failure of the fuel flow-to-load ratio are not parallel with the procedures for data validation following failure of the volumetric stack flow-to-load ratio test in that there is no conditional validation of data. A number of utilities have emphasized that they wish to spend less time and effort preparing and evaluating quarterly reports for units using Appendix D, which are generally smaller and less frequently operated than coal-fired units or oil-fired units that choose to use CEMS (see Docket A–97–35, Item II–E–33). The concept of conditional data validation for fuel flowmeters is not consistent with this objective, because it would introduce additional complexity into the process, would require significantly more time and resources to quality-assure the data, and might require additional DAHS programming. Therefore, the Agency is not proposing the use of conditional data validation for fuel flowmeters.

(c) Fuel Flowmeter Quality Assurance Testing Frequency

Background

Section 2.1.6.1 of Appendix D, as revised by the May 17, 1995 direct final rule, requires regular quality assurance ''recalibrations'' (accuracy tests) of fuel flowmeters at least annually (once every four calendar quarters). For fuel flowmeters that were not used on a regular basis, such as fuel flowmeters used to measure the usage of emergency fuel or backup fuel, or flowmeters installed on peaking units, owners or operators are allowed to do flowmeter accuracy tests once every four quarters when the unit actually combusts the fuel measured by the flowmeter, rather than once every four calendar quarters. Flowmeters can be retested either by using one of the methods incorporated by reference in section 2.1.5.1 of Appendix D to part 75 or by an in-line comparison of the fuel flowmeter against a ''master'' fuel flowmeter using the procedure in section 2.1.5.2 of Appendix D.

Some utilities have expressed concern about the annual fuel flowmeter testing requirement (see Docket A–97–35, Items II–D–20, II–E–13, II–E–14). In many cases, it is neither practical nor cost-effective to modify the fuel pipes (e.g., to install a parallel length of pipe) to allow installation of a master fuel flowmeter for comparison testing. Thus, most utilities must remove a fuel flowmeter from the pipe and return it to a laboratory or to the manufacturer to be retested. In some cases, especially for oil flowmeters, this can be difficult.

Some utilities have raised the issue of whether there should be a minimum time period that a fuel flowmeter is used before a quality assurance test is required. For instance, a utility might test its unit's burners once each quarter for a few hours to ensure that the unit can be operated when needed and may not operate for the rest of the quarter. Under the current rule, the fuel flowmeter would have to be quality assurance tested after four such operating quarters, even though the flowmeter was only used for a few hours in those calendar quarters.

Discussion of Proposed Changes

Today's proposed rule includes a provision that only those calendar quarters in which the fuel measured by the fuel flowmeter is combusted for at least 168 hours would count toward determining the next quality assurance test deadline. The 168-hour time period is roughly equivalent to one week of operation while combusting the fuel measured by a particular fuel flowmeter. A calendar quarter in which the fuel measured by a fuel flowmeter is combusted for 168 hours or more would be called a ''flowmeter operating quarter.'' For example, if a unit combusted oil for 200 hours in the first calendar quarter of the year, 10 hours in the second calendar quarter, 250 hours in the third calendar quarter, and 100 hours in the fourth calendar quarter, then only the first and third calendar quarters would be considered flowmeter operating quarters for the oil flowmeter. Only the first and third calendar quarters would count toward determining the deadline for the next required oil flowmeter accuracy test.

In today's proposed rule, each fuel flowmeter would need to be accuracy tested at least once every four flowmeter operating quarters. However, the deadline for testing infrequently-used meters could not be extended indefinitely. No more than 20 calendar quarters (five years) would be allowed to elapse between successive flowmeter accuracy tests, regardless of the number of ''flowmeter operating quarters'' that have elapsed since the last test. The interval between successive quality assurance tests could also be extended for up to 20 calendar quarters if the quarterly fuel flow rate-to-load procedures in proposed section 2.1.7 of Appendix D were implemented.

Rationale

In evaluating the frequency of fuel flowmeter accuracy testing, EPA considered simply extending the less strict requirement for fuel flowmeter quality assurance testing for peaking units, backup fuel, and emergency fuel to apply to all units and all fuel flowmeters. Thus, quality assurance testing would be required once every four quarters in which the unit combusted the fuel measured by the flowmeter.

One industry representative recommended that the Agency require fuel flowmeter calibrations once every four unit operating quarters, where a unit operates at least 168 hours in the quarter (see Docket A–97–35, Item II–E–13). This approach would treat all fuel flowmeters the same, whether they were used for primary, emergency, or backup fuel.

Another utility suggested that the Agency consider creating some sort of diagnostic test comparing the flow rate of the fuel flowmeter to the unit load (generation) to determine whether the fuel flowmeter readings are degrading over time, rather than specifying a particular frequency for accuracy testing (see Docket A–97–35, Item II–E–22). Although this suggestion was originally referring to problems with corrosion of an orifice plate, such a test could also be used for other types of fuel flowmeters as a check on the quality of fuel flowmeter data.

The Agency also considered extending the typical time between accuracy tests to the equivalent of two years. This time was suggested by a member of the AGA subcommittee responsible for the drafting of AGA Report No. 7 for turbine-type flowmeters (see Docket A–97–35, Item II–E–17). The Agency also considered extending the typical time between accuracy testing to 12 calendar quarters—the equivalent of three years. Three years is the period of time that records must be retained in a file at the source under § 75.54 (or proposed § 75.57).

The Agency also considered allowing fuel flowmeters to continue for up to five calendar years between accuracy tests. This is similar to the current provision in section 2.1.5.2 of Appendix D, which allows a reference fuel flowmeter to be accuracy tested as seldom as once in five calendar years, if the in-line comparison with a master fuel flowmeter shows a 1.0 percent or less difference in their flow rates. A five-year test cycle offers certain administrative advantages. For instance, fuel flowmeters used to provide heat input data for the heat input-versus-load correlation of Appendix E could be accuracy-tested before each Appendix E test (i.e., once every five years). In addition, the five calendar-year period would ensure that fuel flowmeters are tested by the time the unit's operating permit is renewed. Facilities might find this time cycle easier to determine than a time period based upon a number of calendar quarters. However, test data would need to be retained for five years, rather than for three years, the recordkeeping period for most records under part 75. However, the Agency is not proposing this option because five years is far too long a period of time to allow a unit to continue with no checks at all upon the quality of its data. Such an approach would allow the use of data from a fuel flowmeter that potentially had been reading inaccurately for the previous five years.

Another option that EPA evaluated was to establish different fuel flowmeter quality-assurance testing frequencies depending on the fuel measured by the fuel flowmeter. Under this approach, oil flowmeters would need to be tested every four calendar quarters in which oil was combusted. Gas flowmeters would only need to be tested once every five years. The two fuels would be treated differently because units emit less NO_X and far less SO_2 when combusting gas than when combusting oil. In addition, gaseous fuels, particularly pipeline natural gas, should be less corrosive; therefore, a gas flowmeter should be less likely to degrade than an oil flowmeter.

EPA believes that today's proposed approach to reducing the fuel flowmeter quality assurance testing frequency takes into account many of the concerns raised by utilities. All unit types and fuel types would have the same frequency of testing. This would avoid confusion that could follow from an approach that set different requirements for fuels or units that are used less frequently. A group of utilities had indicated that they prefer a more consistent approach (see Docket A–97–35, Item II–E–13). Under today's proposal, infrequently-used fuel flowmeters (e.g., meters for backup fuel or emergency fuel) would only need to be calibrated once every five years. When a facility renews its operating permit, the permitting agency could verify that all fuel flowmeters have been tested at least once in the previous five years.

The minimum period of 168 hours of fuel flowmeter usage which defines a ''flowmeter operating quarter'' is consistent with the definition of a ''QA operating quarter'' in Appendix B in today's proposed rule for the quality assurance of CEMS. The Agency believes that using a consistent minimum number of hours in a calendar quarter for both CEMS and fuel flowmeters will make implementation easier for facilities and air regulatory agencies. In addition, 168 hours should be a sufficiently long period of time to ensure that short-term usage of backup fuel or emergency fuel or short-term tests of a unit do not trigger unnecessary quality assurance testing.

Today's proposed rule would also provide more flexibility in the methods that could be used for fuel flowmeter quality assurance testing. As discussed above in Section III.P.2 of this preamble, a new testing procedure has been proposed that would allow a facility to test flow rate-to-load ratio of the fuel flowmeter while leaving it installed. Thus, the Agency believes that the overall burden of fuel flowmeter testing has been significantly reduced. In addition to the reduced frequency of testing discussed above, the Agency believes the less burdensome testing procedures should address concerns of the regulated community.

The Agency requests comment on whether facilities would prefer to base the frequency of fuel flowmeter quality assurance testing on the type of fuel used or the amount of time the fuel flowmeter is used. Under the first approach, gas flowmeters would receive greater regulatory relief. Under the second approach, which is being proposed in today's rule, infrequently-used flowmeters (typically oil flowmeters) would receive greater regulatory relief.

(d) Orifice, Nozzle, and Venturi Visual Inspections

Background

Section 2.1.6 of Appendix D, as revised in the May 17, 1995 direct final rule, created special provisions for the ongoing quality assurance testing of orifice fuel flowmeters. Orifice-, nozzle-, and venturi-type fuel flowmeters are designed and installed within a set of physical specifications, such as the orifice diameter (see Docket A–97–35, Item II–D–13). Maintaining these physical specifications determines the flowmeter's ability to read accurately. Thus, it is not necessary to take an orifice-, nozzle-, or venturi-type flowmeter out of line and send it to a laboratory to determine its accuracy.

After installation of an orifice-, nozzle-, or venturi-type flowmeter is complete, the two major factors that contribute to error in flow readings are: drift in the transmitters (or transducers) which determines the total pressure, differential pressure and temperature, and corrosion of the primary element (e.g., the orifice plate) itself. Quality assurance testing of the transmitters is discussed in the next section of the preamble. In order to identify cases where error might result from corrosion of the orifice plate, the May 17, 1995 direct final rule added a requirement for an annual visual inspection of the orifice plate. If an orifice plate fails the inspection, then the facility must perform a test on the transmitters during the next calendar quarter. A procedure for visual inspections is given in Appendix B of part 2 of American Gas Association (AGA) Report No. 3, which is one of the accepted standards for installation and use of orifice flowmeters.

Some facilities have expressed concern with the frequency of visual inspections (see Docket A–97–35, Items II–D–20, II–E–13, II–E–14). This process must be done either with a tool, such as a boroscope, or else the primary element must be removed from the pipe and lifted out to be inspected. In the case of large, heavy orifices, it is necessary to use a crane to remove the orifice. Fuel must not be flowing through the pipe while the orifice plate is being removed (see Docket A–97–35, Item II–E–8).

The current provisions of Appendix D to part 75 do not explicitly state the consequences of failing a quality assurance test. Section 2.1.5.1 of Appendix D states that if a fuel flowmeter exceeds the flowmeter accuracy of ± 2.0 percent of the upper range value, then the flowmeter may not be used under part 75. Section 2.1.5.2 states that if a fuel flowmeter's accuracy exceeds ± 2.0 percent of the upper range value, then the flowmeter must be recalibrated to meet that accuracy, or it must be replaced with another flowmeter that meets the specification. Neither section explicitly states the impact upon the validity of data if a test is failed. However, if fuel flowmeter systems are to be treated parallel with continuous emission monitoring systems under § 75.21(e)(2), the consequences of failing a quality assurance test for a fuel flowmeter or an inspection of the primary element should result in the monitor being considered out-of-control and the data being considered invalid.

In section 2.1.6.1 of Appendix D, the specific consequence of failing a visual inspection of the primary element is that the transmitters must be tested in the following calendar quarter, rather than waiting until the regular annual calibration is required. However, no mention is made of any mandatory corrective action(s) to eliminate the corrosion problem.

Discussion of Proposed Changes

Section 2.1.6.6 of Appendix D in today's rulemaking proposes to require visual inspections of primary elements (i.e., orifice, nozzle or venturi) at the frequency recommended by the manufacturer or once every three years, whichever is more frequent. The Agency solicits comment on the proposed frequency of visual inspections.

The proposed rule would also explicitly require repair or replacement of the primary element and invalidation of data when a visual inspection is failed. Once the primary element is replaced or repaired, the new or repaired primary element would have to demonstrate that it meets the overall flow rate accuracy of ± 2.0 percent of the upper range value. This could be demonstrated by showing that the new or repaired primary element meets the design and installation requirements of AGA Report No. 3 or ASME MFC–3M, the same methods required for initial certification. Alternatively, the flow rate accuracy could be demonstrated by testing the fuel flowmeter against a reference fuel flowmeter using the provisions of section 2.1.5.2 of Appendix D. Finally, whenever a primary element is repaired, the fuel flowmeter transmitters would also have to be tested before the fuel flowmeter is used to provide quality assured data.

Rationale

During the process of reviewing certification applications for units using orifice flowmeters, the Agency learned of one plant where orifice corrosion was a serious problem. This utility had an orifice flowmeter which had been installed in the 1960's. This utility did not have documentation of the standard used to install the orifice as a demonstration of the meter's accuracy. In order to qualify for certification, the utility inspected the orifice. The utility personnel discovered that the orifice had been completely eaten away and was incapable of reading the flow rate (see Docket A–97–35, Item II–E–22). The utility replaced the orifice before it was able to have its fuel flowmeter certified. In addition, it was required to invalidate the flow rate data from the orifice meter and substitute for the missing data. Based upon this experience, the Agency believes that corrosion of an orifice can be a problem, and that in severe cases of corrosion, replacement of the orifice is necessary.

Despite this, many utilities have expressed concern over the difficulty of removing an orifice from place for visual inspection (see Docket A–97–35, Items II–D–20, II–E–13, II–E–14), because removal requires halting the flow of gas through the pipeline in order to remove the orifice, which can be expensive (see Docket A–97–35, Item II–E–8).

Utilities have provided the Agency with several suggestions for reducing the frequency of primary element inspections. One industry group recommended that the Agency reduce the inspection frequency to once every five years, to be coordinated with renewal of the plant's operating permit under title V of the Act (see Docket A–97–35, Items II–D–20, II–E–13, and II–E–14). One utility representative mentioned that most orifice manufacturers recommend an inspection once every three years; thus, he recommended that the Agency require visual inspections the earlier of once every three years or the time period specified by the manufacturer (see Docket A–97–35, Item II–D–41). Another utility suggested that the Agency consider creating some sort of diagnostic test comparing the flow rate of the fuel flowmeter to unit load (generation) to determine whether the fuel flowmeter readings are degrading over time, rather than specifying a particular time period (see Docket A–97–35, Item II–E–22).

EPA agrees that it would be helpful to facilities to reduce the frequency of visual inspections from their current annual frequency. Having considered all of the options suggested by the utilities, the Agency is proposing that the primary element of all nozzle, venturi and orifice fuel flowmeters be visually inspected at the frequency recommended by the manufacturer or once every three years, whichever is the more frequent. The Agency believes that up to three years between visual inspections is a technically sound period of time that will assure the quality of fuel flow rate data, while providing regulatory relief from the current annual requirement.

The Agency also has reconsidered the consequences of failure of a visual inspection. The May 17, 1995 direct final rule added a requirement to test a flowmeter's transmitters in the calendar quarter following a failed inspection, but the rule does not explicitly require that the primary element be repaired or replaced, nor does it explicitly require data from the fuel flowmeter to be invalidated.

Today's proposed rule would require the primary element to be removed following a failed visual inspection and would require the problem to be corrected. The Agency believes that it is appropriate to provide two options for correcting the problem: either replace the element with a new one or repair it. This would provide flexibility to facilities, while still assuring that the fuel flowmeter will be repaired to give quality assured data.

Today's proposed rule would also change the timing of the requirement for fuel flowmeter transmitter or transducer testing if a primary element fails its visual inspection. The Agency believes that it would be appropriate also to test the fuel flowmeter transmitters before the fuel flowmeter is placed into service again. This would be a more thorough quality assurance check of the entire fuel flowmeter than simply addressing the problem with the primary element. Thus, when the fuel flowmeter is placed into service again, its accuracy would be tested as fully as possible. In addition, EPA proposes to remove the requirement for a test on the flowmeter transmitters in the calendar quarter following a failed visual inspection. This requirement might be appropriate if it seemed that transmitter drift was likely to be a problem or if the Agency had no other means of assuring the quality of the data from the flowmeter after a problem with the primary element was known to have occurred. However, the Agency believes that problems with the primary element are separate from problems with drift in the transmitters. Because today's proposal would require a check on the fuel flowmeter transmitters after repair or replacement of the primary element, requiring an additional test of the transmitters in the following calendar quarter appears to be unnecessary.

The proposed rule gives procedures for data validation when a primary element fails a visual inspection. The element would have to be replaced or repaired, and the transmitters would have to be tested before data would again be valid from the fuel flowmeter. During the period in which the flowmeter data are considered invalid, the appropriate missing data substitution procedures would be used. The Agency has clarified that these data validation procedures would also apply to failures of other fuel flowmeter quality assurance tests. EPA believes that this will make facilities' obligations clearer. In addition, the Agency believes that fuel flowmeter systems should be treated as consistently as possible with CEMS. Consistent treatment simplifies the part 75 requirements and is more equitable for sources using different monitoring approaches.

(e) Orifice, Venturi, and Nozzle Flowmeter Transmitter Testing

Background

As discussed previously, once an orifice-, nozzle-, or venturi-type flowmeter has been installed, one of the major causes of error in the measured flow rates is drift in the transmitters or transducers that determines the total pressure, differential pressure, and temperature. The flow measurement error for these types of flowmeters is a combination of the errors in these individual transmitters or transducers and a constant error value associated with the physical dimensions of the primary element. The May 17, 1995 direct final rule added a requirement that flowmeter transmitters be tested at least annually. The transmitters are also required to be retested in the next calendar quarter if the overall flow rate error is greater than 1.0 percent of the upper range value of the flowmeter. For practical purposes, this requires a facility to know the error from the physical dimensions of the primary element in order to determine if the flowmeter meets the overall accuracy requirement.

Some utilities asked the Agency how to determine the overall flowmeter accuracy from individual transmitter values (see Docket A–97–35, Item II–E–31). EPA addressed this issue in Policy Guidance (see Docket A–97–35, Item II–I–9, Policy Manual, Question 10.17). This guidance included a formula for calculating total flowmeter accuracy from error in transmitter readings for differential pressure, static pressure and temperature, and error from all other sources (i.e. physical dimensions of the primary element). Some utilities indicated that they do not always have information available on the constant error from other portions of the primary element (see Docket A–97–35, Item II–E–13). The policy guidance also indicated that a facility could report test results electronically using the highest amount of error from any of the three transmitters. Provided that the highest error from an individual transmitter is 1.0 percent of the upper range value of the transmitter or less, the overall flowmeter accuracy will be less than 2.0 percent of the upper range value (see Docket A–97–35, Item II–I–10).

EPA has also observed that transmitter test data reported for orifice-, nozzle-, and venturi-type flowmeters have not been consistent. Some facilities test each transmitter once at three different levels, including a low, middle, and high value (see Docket A–97–35, Item II–D–16). Others test each transmitter at five different levels, including zero, full scale, and three intermediate levels (see Docket A–97–35, Item II–D–17). The Agency had previously issued some guidance on reporting test results, both for orifice flowmeters and other flowmeters (see Docket A–97–35, Items II–I–4, p. 3–58, and II–I–9, Policy Manual, Questions 10.17 and 12.27). However, this guidance appears to have been insufficient, as utilities have continued to request guidance in how to perform and report test results (see Docket A–97–35, Item II–D–21). Questions have included the number of levels at which transmitters should be tested, whether all of these levels must be non-zero, the number of times the transmitter should be tested at a particular level, if results may be reported in hardcopy or should be reported electronically, and how data should be reported electronically.

Discussion of Proposed Changes

Today's proposed rule would make the requirement to assess the total accuracy of orifice-, nozzle-, and venturi-type fuel flowmeters from the transmitter/transducer test results an option. As an alternative, proposed section 2.1.6.5 in Appendix D would allow each of the three transmitters (static pressure, differential pressure, and temperature) individually to meet an accuracy specification of 1.0 percent of the upper range value of the transmitter.

Today's rulemaking also proposes a procedure in section 2.1.6.1 of Appendix D for testing the accuracy of orifice-, nozzle-, and venturi-type fuel flowmeters. Each transmitter would be calibrated against NIST-traceable reference values at least once at the zero level and at a minimum of two other levels across the range of values that the transmitter reads during normal unit operation. Note that in many instances this would be a portion of the full-scale range of the transmitter, rather than the entire range. In addition, revised section 2.1.6.2 of today's proposed rule includes the new Equation D–1a to clarify how to calculate the error from an individual transmitter.

Finally, today's proposal would clearly specify the consequences of failure of an accuracy test on transmitters in section 2.1.6.5 of Appendix D. Just as CEM data are considered invalid from the time that a quality assurance test is failed until the test is subsequently passed, data from a fuel flowmeter would be considered invalid from the date and time of a failed transmitter accuracy test until the date and time of a passed transmitter accuracy test.

Rationale

The Agency considered two main options for determining the accuracy of a transmitter or transducer of an orifice-, nozzle-, or venturi-type fuel flowmeter. In the first approach (which is consistent with current policy guidance), these types of fuel flowmeters would be required to meet an accuracy of 2.0 percent of the upper range value of the total flow rate of the fuel flowmeter. The accuracy would be determined using the square root of the sum of the squares of all sources of error in the fuel flowmeter, according to the following equation:

$$\frac{dq_v}{q_v} = \left(K^2 + \left[\frac{-dP_f}{2P_f}\right]^2 + \left[\frac{d\Delta P}{2\Delta P}\right]^2 + \left[\frac{dT_f}{2T_f}\right]^2 \right)^{1/2}$$

Where: dq_v/q_v = Error in the volumetric flow rate due to transmitter drift at a given level;
K = Original error resulting from installation of orifice (including all other variables);
dP_f = Average difference between static pressure transmitter reading(s) and reference static pressure reading(s) at a given level;
P_f = Average reference static pressure reading at a given level;
$d\Delta P$ = Average difference between differential pressure transmitter reading(s) and reference differential pressure reading(s) at a given level;
ΔP = Average reference differential pressure reading at a given level;
dT_f = Average difference between temperature transmitter reading(s) and reference temperature reading(s) at a given level; and
T_f = Average reference temperature reading at a given level.

If the error calculations for error from the primary element of the fuel flowmeter were not available, then the facility could use a default value of 1.0 percent of the upper range value error from all parts of the fuel flowmeter except for the differential pressure, static pressure, and temperature transmitters. (In other words, the factor ''K'' in the equation above would be equal to 1.0 percent of the upper range value.) However, this would almost certainly trigger the requirement for recalibration or retesting of the accuracy of the transmitters in the next calendar quarter because the fuel flowmeter accuracy would exceed 1.0 percent of the upper range value. Based upon statements from the American Gas Association, it is the Agency's understanding that for an orifice-, nozzle-, or venturi-type fuel flowmeter meeting AGA Report No. 3 or ASME MFC–3M, the maximum error from portions of the meter other than the transmitters should be 1.0 percent of the upper range value (see Docket A–94–16, Item II–F–2, and this Docket, A–97–35, Item II–E–18).

In the second approach to determining error for orifice-, nozzle-, and venturi-type fuel flowmeters, each transmitter or transducer would be tested separately for accuracy, and each transmitter or transducer would be required to meet an accuracy specification of 1.0 percent of the full scale range of the transmitter. Under this approach, it would no longer be necessary to determine the total error in the flowrate from the fuel flowmeter. Because this proposal would eliminate the calculation of the total error in flowrate, there would no longer need to be a requirement to retest the accuracy of the transmitters in the next calendar quarter when the total fuel flowmeter accuracy exceeds 1.0 percent of the upper range value.

In today's rule, EPA proposes to allow both of the approaches described above for calculating the total flowmeter accuracy. The second approach (i.e., calculating individual transmitter accuracy) is simpler than calculating the total error in the flow rate, although it is less directly related to the accuracy of SO_2 mass emission rate and heat input measurements than the fuel flowrate. An individual transmitter accuracy specification of 1.0 percent of the full scale of each transmitter would be slightly stricter than a total fuel flowmeter accuracy specification of 2.0 percent of the upper range value of the fuel flowmeter, because one transmitter could potentially have an error greater than 1.0 percent of its full scale range while the entire error in the fuel flowrate would still be less than 2.0 of the upper range value of the fuel flowmeter. Thus, the option of calculating the total error in the fuel flowrate has been retained in today's proposal. At least one industry representative suggested allowing both approaches of calculating accuracy when testing transmitters of an orifice-, nozzle-, or venturi-type fuel flowmeter (see Docket A–97–35, Item II–E–24).

The Agency considered two main methodologies for transmitter testing on orifice-, nozzle-, and venturi-type flowmeters. The first method would be to require a five-point test that checks the linearity of the transmitter. The transmitter would be tested against an NIST traceable method (e.g., testing a pressure transmitter against an NIST traceable deadweight transmitter) at the following percentages of the full scale range of the transmitter: 0.0 percent, 20.0 to 30.0 percent, 40.0 to 60.0 percent, 70.0 to 80.0 percent, and 100.0 percent. This is the general approach that was taken by many utilities that provided transmitter calibration results to EPA (see Docket A–97–35, Items II–D–26 through 28).

The second method would be to require a comparison to an NIST traceable transmitter at the zero level and at least two other levels across the range of readings on the transmitter or transducer. This would be different from the first method in that the transmitter would only need to be tested across the range where the transmitter is actually used. For example, if a fuel flowmeter transmitter's readings never rise higher than 60.0 percent of the full scale range of the transmitter, then the transmitter could be tested at 0.0 percent, 30.0 percent, and 60.0 percent of full scale. These procedures are reflected in the proposed revised section 2.1.6.1 of Appendix D.

The Agency is proposing the second method in today's rule, i.e., that each individual transmitter must be tested at three or more points across its normal range of readings. EPA realizes that it is standard industry procedure to test a fuel flowmeter at five levels across its entire range (see Docket A–97–35, Item II–E–24). However, the Agency is aware of at least one case where a fuel flowmeter failed to meet an accuracy specification of 2.0 percent of the upper range value when it was tested at 100.0 percent of the upper range value. However, the fuel flowmeter was never used to measure a rate greater than roughly 55.0 percent of the upper range value (see Docket A–97–35, Item II–D–15). If this flowmeter had only been required to test across the range where the fuel flowmeter actually measured fuel flow rates, it would have met the accuracy specification. Section 2.1.5 requires fuel flowmeters that are tested against a master fuel flowmeter to be tested across the range of measured fuel flowrate only. Requiring testing of each transmitter at three or more points across the range of all readings would still ensure that the transmitter reads accurately across all readings, while reducing the possibility that the transmitter might fail an accuracy test because of a high error reading at the high end of the transmitter's range where the transmitter is never used. At least one utility has mentioned that this would be helpful (see Docket A–97–35, Item II–E–24). The Agency solicits comment on the proposed approach.

Today's proposed rule also includes Equation D–1a for calculating error from an individual flowmeter transmitter. The Agency feels that this would clarify the calculation. It also would prevent the possible confusion that would occur if a facility attempted to use the existing Equation D–1, which is designed for a fuel flowmeter that is compared to another fuel flowmeter.

Finally, under today's proposal, when a transducer or transmitter test is failed, a fuel flowmeter would be considered out-of-control, and its data would be considered invalid until the date and time the transmitter is retested and meets an accuracy of 1.0 percent of its full scale.

(f) Reporting of Fuel Flowmeter Testing Data

Background

As mentioned above in Section III.P.5 of the preamble, utilities have had questions about how to report the results of their fuel flowmeter testing data. In certification applications and quality assurance testing results, utilities have reported test data in a variety of ways. In some cases, the Agency was unable to determine the flowmeter accuracy from the testing information provided because data were not labeled as reference flow rate data, flowmeter data, or accuracy data. For example, for turbine flowmeters, data on the reproducibility of the ''K-factor'' was often presented. However, these are not flow rate data, nor is it clear what the accuracy of the flow rate is (see Docket A–97–35, Item II–D–9). Sometimes data were presented in tables. Other data were presented in graphs (see Docket A–97–35, Item II–D–9). In many cases, Agency or state environmental agency staff needed to request additional information from utilities to determine if they had met the accuracy requirement for fuel flowmeters (see Docket A–97–35, Items II–C–3, II–C–5).

To clarify the requirements for certification applications for fuel flowmeters, the Agency issued policy guidance about the type of information to provide (see Docket A–97–35, Item II–I–9, Policy Manual, Question 12.27). This guidance included a sample table with an example of how to submit information for a fuel flowmeter that is tested against a master meter or flow prover reference value.

Discussion of Proposed Changes

EPA proposes to add a sample table to Appendix D (Table D–1) for summarizing the results of accuracy tests of fuel flowmeters that are calibrated by comparison against other fuel flowmeters or a prover. In addition, EPA proposes to add a separate table for summarizing the results of calibrations of the transmitters or transducers of an orifice-, nozzle-, or venturi-type fuel flowmeter.

Rationale

In today's proposed rule, EPA would provide clarification in the form of a table for summarizing the quality assurance test results of fuel flowmeters that are compared against other fuel flowmeters or a prover. A second table is provided for summarizing the results of calibrations of transmitters or transducers of an orifice-, nozzle-, or venturi-type fuel flowmeter. This second table accounts for differences in the testing procedure for transmitters or transducers. In both cases, EPA has tried to make clear what critical information would have to be reported in order to demonstrate that the fuel flowmeter (or the transmitter of an orifice-, nozzle-, or venturi-type fuel flowmeter) meets the accuracy specification. In addition, EPA will design revised electronic record types with this type of information so that test results may be more easily reported electronically. The Agency is aware that this has been difficult or confusing for some utilities (see Docket A–97–35, Items II–D–23, and II–I–9, Policy Manual, Question 12.27). The Agency also considered adding a sample graph for reporting accuracy data. However, EPA feels that it would be easier to compare the data in tabular format and to enter it into the electronic data format than to enter values from a graph. Most of the graphs provided to EPA have been relatively easy to read, and there appears to be less of a need for an example to be included in Appendix D (see Docket A–97–35, Item II–D–9).

7. Use of Uncertified Commercial Gas Flowmeter

Background

Currently, a facility using Appendix D may either install its own gas flowmeter or use a commercial gas flowmeter owned by a pipeline natural gas supplier, provided that the meter meets the reporting and accuracy requirements of Appendix D, including initial certification and continuing quality assurance requirements. Some utilities have suggested to EPA that they would like to be able to use data from the commercial billing of pipeline natural gas without having to demonstrate that the gas flowmeter meets initial certification and continuing quality assurance requirements (see Docket A–97–35, Items II–D–45, II–D–49). Those utilities assert that because the amount of gas measured is already subject to market forces, the monitoring should be sufficiently accurate for the Acid Rain Program. Utilities have mentioned that gas companies often are already conducting meter calibrations as quality assurance, but utility customers generally do not have access to this information (see Docket A–97–35, Items II–D–49, II–E–33). Facilities would find it advantageous to rely upon their commercial billing charges for accounting for pipeline natural gas usage because they would need to devote less time, effort, and money to the maintenance of gas fuel flowmeters. This is particularly desirable to facilities since the SO_2 emissions from pipeline natural gas are extremely low compared to the SO_2 emissions from other fuels.

Discussion of Proposed Rule Changes

Proposed section 2.1.4.2 of Appendix D would allow facilities to record and report the gas flow rate, the heat input rate, and emission values based on gas flowmeter readings from a flowmeter used for commercial billing of pipeline natural gas without meeting the certification requirements of section 2.1.5 of Appendix D or the quality assurance requirements of section 2.1.6 of Appendix D under specified conditions. Relief from the certification and quality assurance requirements for gas flowmeters used for commercial billing would be limited to flowmeters where the gas flowmeter is used for commercial billing under a contract with another company having no common owner with the unit(s) served by the flowmeter, which would exclude any gas flowmeters used for transfers of gas between different divisions, subsidiaries, or affiliates of the same company.

If the commercial billing gas flowmeter would be used without undergoing certification or quality assurance under part 75 requirements, then the designated representative would need to report hourly records of the gas flow rate, the heat input rate, and emissions due to combustion of pipeline natural gas, as well as heat input rate for each unit if the commercial billing gas flowmeter is on a common pipe header. This would be similar to the reporting currently done for a certified gas flowmeter, but no quality assurance records would be required. The quarterly report would contain record types 303 for fuel flow rate and heat input rate, record type 314 for the SO_2 mass emission rate, either record type 320 or 323 for the NO_X emission rate in lb/mmBtu, and either record type 330 or 331 for CO_2 mass emissions. It also would be necessary for the designated representative to identify the commercial billing gas flowmeter in Table B (electronic record type 510) of the monitoring plan for the unit.

So long as the records from the commercial billing gas flowmeter are the values used for commercial billing, the designated representative would report those values from the commercial billing gas flowmeter without adjustment. If the records from the commercial billing gas flowmeter are not consistent with the values used for commercial billing because of some problem that needs to be reconciled between the gas vendor and the facility customer, then the designated representative would consider the readings from the commercial billing gas flowmeter to be invalid for that billing period and would report hourly records using the missing data procedures for fuel flowmeter data found in section 2.4 of Appendix D for all hours of gas combustion during that billing period. A facility would not be able to use the commercial billing value in the quarterly report if the commercial billing value was different from the value on the commercial billing gas flowmeter.

Rationale

Utilities have suggested that the purchase of pipeline natural gas from a vendor is subject to market forces that ensure accurate monitoring (see Docket A–97–35, Item II–D–49). Utilities have stated that gas vendors already have procedures for certification and meter calibration and that the gas vendors have an even greater incentive than utilities to maintain a high monitor ''uptime'' (i.e., availability) for gas fuel flowmeters. Typically, utilities will work together with their gas vendors if they believe there is any sort of discrepancy in their monthly billing for pipeline natural gas (see Docket A–97–35, Items II–D–33, II–E–33).

The Agency believes that this argument is reasonable. However, EPA also understands that some utilities require their gas vendor to correct their billing values based upon the evidence of the utility's own gas flowmeters. In addition, it is likely that utilities will be combusting more pipeline natural gas in the future as they respond to current and potential future environmental requirements for reducing NO_X and CO_2. Therefore, the Agency believes that there must be conditions placed upon reporting emissions and heat input for the Acid Rain Program from gas flowmeters used for commercial billing if the gas flowmeters will not be required to meet the certification and quality assurance requirements of part 75.

The Agency is proposing to limit the waiver from certification and quality assurance requirements to commercial billing gas flowmeters that are used in billing transactions between companies with entirely different ownership (e.g., a pipeline natural gas vendor and a separate electric utility company with no owners in common). Some utilities requested the relief from quality assurance requirements based upon the reasoning that a gas vendor would do its own quality assurance and maintenance, and perhaps with better accuracy than a utility would be able to maintain, but the utility would not necessarily have access to the test results and would not have control over what quality assurance might occur (see Docket A–97–35, Items II–D–49, II–E–33). This reasoning is sound if the utility and the gas vendor have no common owners, but it would not necessarily be sound if a gas supplier were part of the same company as the electric utility. Also, utilities suggested that a gas vendor may have an incentive to overstate the amount of gas in order to bill more, rather than having an incentive to underestimate or under-report (see Docket A–97–35, Item II–D–49). Once again, this argument is reasonable if the gas vendor is a separate entity, but may not be reasonable if the gas supplier has common owners with the electric utility. Therefore, today's proposed rule includes a limitation on the waiver from certification and quality assurance requirements for commercial billing gas flowmeters to those gas flowmeters used for commercial billing between companies with separate ownership.

EPA solicits comment on the proposed approach of allowing the use of uncertified fuel flowmeters for purposes of determining emissions and heat input in the limited circumstances described above.

EPA has proposed in today's rule that a facility may only report data from a commercial billing gas flowmeter if the data are used in a commercial transaction. A group of utilities suggested that the Agency allow facilities to report quarterly SO_2 emissions based on gas supplier data, including any reconciliation that has taken place (see Docket A–97–35, Item II–D–45). Such a reconciliation between a gas vendor and its customer may occur if the customer believes there is a discrepancy in their monthly billing for pipeline natural gas (see Docket A–97–35, Items II–D–33, II–E–33). If a facility and its gas vendor determined that gas supply information from a fuel flowmeter were not sufficiently accurate to purchase gas, then the Agency presumes the gas supply information is also not sufficiently accurate for emissions accounting.

The Agency also considered whether a facility should be able to use the reconciled gas volumes agreed upon for billing if that value were not from the commercial billing gas flowmeter. In general in the Acid Rain Program, hand-typed corrections to emissions data are not permitted (see Docket A–97–35, Item II–I–14), with the primary exception of cases where sound engineering judgement indicates there is an obvious error that cannot exist, such as a negative concentration reading.

Allowing a facility to enter a commercial billing value by hand would contradict this basic reporting policy of the Acid Rain Program.

Today's proposed rule also specifies the type and frequency of information that would be required to be reported by a facility concerning pipeline natural gas. Some utilities have requested the ability to report only a quarterly cumulative SO_2 mass emission number for emissions from gas (see Docket A–97–35, Item II–D–45). However, the Agency believes that there are several reasons for maintaining hourly heat input rate and emissions data during combustion of pipeline natural gas. First, hourly data is the most useful interval of data for air quality modeling in order to see if progress is being made in reducing emissions. Hourly data from combustion of pipeline natural gas will become even more important as more units switch to combusting pipeline natural gas in order to reduce their emissions. In addition, hourly data are easier to check for anomalous values than quarterly data. Further, hourly heat input rate data is necessary in order to determine the NO_X emission rate when using the NO_X-versus-heat input rate correlation of Appendix E to part 75. Also, since hourly data are already being recorded, reported, and processed by automated computer data acquisition and handling systems, a change to this requirement would require costly reprogramming for industry and for EPA. For all of these reasons, EPA is proposing that facilities continue to report hourly gas flow rates, heat input rates, and emissions from commercial billing gas flowmeters that are not required to meet the certification and quality assurance requirements of part 75.

Q. Appendix G

1. Use of ASTM D5373–93 for Determining the Carbon Content of Coal

Background

Appendix G to part 75 provides procedures for determining CO_2 emissions from fuel sampling and analysis instead of from a CO_2 CEMS and a flow monitor. Section 2.1 of Appendix G includes a mass-balance equation for determining CO_2 (see Equation G–1), the frequency for sampling fuel, and the specific methods for analyzing fuel for carbon content. Section 2.3 of Appendix G provides a method for determining CO_2 mass emissions from a gas-fired unit from its heat input using Equation G–4. Some facilities use Appendix G procedures to determine CO_2 mass emissions every day for their units. Other facilities might use the procedures of section 2.1 of Appendix G only to provide CO_2 mass emissions during extended periods when CO_2 data are missing from their CO_2 CEMS, under the provisions of § 75.36.

A utility and its fuel analysis laboratory contacted EPA concerning use of an additional ASTM method for analysis of carbon content. The industry staff felt that the new infrared analysis method, ASTM D5373–93, was the most up-to-date method and that this method should be at least as accurate as the methods specified in Appendix G to part 75 (see Docket A–97–35, Item II–D–25). Based upon the precision and bias information in the method, EPA approved its use under § 75.66 (see Docket A–97–35, Item II–C–16).

Discussion of Proposed Changes

Today's proposed rule would allow the use of ASTM D5373–93, "Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke," for Section 2.1 of Appendix G to part 75. This method is for determining the carbon content of coal. ASTM D5373–93 would also be incorporated by reference in § 75.6. Facilities would also continue to have the option to use ASTM D3178–89 to analyze coal for carbon content.

Rationale

EPA has previously approved the use of ASTM D5373–93 for analyzing the carbon content of coal (see Docket A–97–35, Item II–C–16). The Agency believes this method is of sufficient accuracy for use in the Acid Rain Program. In addition, EPA historically has accepted analytical methods from standard-setting organizations such as the American Society for Testing and Materials (ASTM). The Agency solicits comment on the use of ASTM D5373–93 for analyzing the carbon content of coal.

2. Changes to Fuel Sampling Frequency

Background

Section 2.1 of Appendix G (as revised by the May 17, 1995 direct file rule) specifies that fuel sampling should be done weekly for gas or oil for each shipment for diesel fuel and at least once per month for gaseous fuel. The sampling frequencies for diesel fuel and for gaseous fuel are consistent with the frequency for sampling under Appendix D to part 75.

Most gas-fired and oil-fired units that perform fuel sampling for sulfur content under Appendix D also perform fuel sampling for carbon content. Today's proposed rule would reduce the frequency with which facilities need to sample oil or gas under Appendix D.

Discussion of Proposed Changes

The fuel sampling frequency specified in section 2.1 of Appendix G would be made consistent with the proposed requirements for Appendix D oil and gas sampling. Thus, all oil samples could be taken upon delivery, either from the delivery vessel itself or from the storage tank after a delivery is transferred. Gas samples would be taken monthly (for pipeline natural gas), for each shipment (for gases delivered in lots), or daily (for fuels that are analyzed daily for sulfur). Coal samples would continue to be taken weekly.

Rationale

Appendix D of today's proposed rule would reduce the required sampling frequency of oil and gaseous fuels delivered in lots. Based upon information provided by one utility, the variability of carbon content in oil is less than the variability of sulfur content (see Docket A–97–35, Item II–D–18). Some utilities have stated that they would prefer the procedures for sulfur and GCV to be similar (see Docket A–97–35, Item II–D–24). Based upon this statement, the Agency believes that facilities would also prefer to have consistent fuel sampling procedures for Appendices D and G. Therefore, the Agency believes it is appropriate to make the fuel sampling frequency for carbon analysis under Appendix G consistent with the fuel sampling frequency for sulfur content under Appendix D. Similarly, section 5.5 of Appendix F would be revised to make the gas sampling frequency consistent with Appendix D. The Agency solicits comment on the proposed changes to the fuel sampling frequency.

3. Addition of Missing Data Procedures for Fuel Analytical Data

Background

Appendix D provides procedures for substituting missing fuel analytical information, either for sulfur or GCV. However, Appendix G to part 75 does not specify what should be done if carbon content data are missing.

Some software programmers asked EPA what missing data procedures should be used for carbon content data (see Docket A–97–35, Item II–E–5). The Agency responded to this question at a public conference and in policy guidance (see Docket A–97–35, Items II–E–5, and II–I–9, Policy Manual, Question 6.3). In its policy guidance, EPA stated that facilities should "[f]ill in the most recent carbon content . . . available for that fuel type (gas, oil or coal) of the same grade (for oil) or rank (for coal). If at all possible, use a carbon content value from the same fuel supply.''

Discussion of Proposed Changes

Today's proposed rule would allow facilities to substitute for missing carbon content prior to January 1, 2000, using either the most recent carbon content for that fuel type, grade and rank, or procedures parallel to those of Appendix D. Beginning January 1, 2000, facilities would substitute for missing carbon content data using procedures consistent with Appendix D. For gaseous fuels and for oil sampled manually, these procedures would provide for a conservative maximum carbon content value. Specifically, the permissible conservative carbon content values would be either the maximum carbon content measured in the previous calendar year or, if this information were not available, a default value based upon handbook fuel characteristics. For weekly coal samples or composite oil samples, CO_2 mass emissions would be calculated using the highest carbon content from the previous four carbon samples available.

Rationale

Software programmers have already indicated that it is useful to have a procedure for filling in missing carbon content data for purposes of programming (see Docket A–97–35, Item II–E–5). Some utilities have stated that they would prefer the missing data procedures to be similar for both sulfur and GCV, even if both values are conservative (see Docket A–97–35, Item II–E–24). Therefore, the Agency believes that facilities would also prefer to have Appendix G missing data procedures for carbon content that are parallel with those for sulfur content and GCV in Appendix D. Thus, today's proposal would allow for missing data for manual oil samples or for gaseous fuel using the maximum carbon content measured in the previous calendar year or, if this information were not available, a default value based upon handbook fuel characteristics.

In determining the conservative default carbon content values that would be used for missing data substitution in the event that no previous carbon content samples are available, the Agency consulted several handbook reference tables on fuel characteristics. Specifically, the Agency reviewed handbook values for the carbon content of coal (of various ranks), oil (of various grades), and gas (of different types). (see Docket A–97–35, Items II–I–18, II–I–19, II–I–20). In the case of coal, there was a fairly wide range of carbon content values for different ranks of coal. Therefore, today's rule would propose separate default carbon content values for Anthracite, Bituminous, and Subbituminous/Lignite. In contrast, the carbon content values for different grades of residual oil were fairly consistent. For this reason, today's rule proposes a single default carbon content value for all grades of oil. Finally, for gaseous fuels, the handbooks which were reviewed presented a fairly narrow range of values for natural gas but a much wider range of values for other types of gaseous fuels. Therefore, today's rule proposes a value for natural gas and a separate, conservative value for all other types of gaseous fuels.

The Agency solicits comment on the proposed revisions to the missing data procedures under Appendix D.

R. Reporting Issues

1. Partial Unit Operating Hours and Emission and Fuel Flow Rates

Background

For affected units that use CEMS to account for emissions under part 75, hourly emission rates of SO_2 (in lb/hr), NO_X (in lb/mmBtu), and CO_2 (in tons/hr), and hourly heat input rates (in mmBtu/hr) are calculated using the applicable equations in Appendix F. For affected units that use fuel flow meters and fuel analysis (or default emission rates) rather than CEMS, the applicable equations in Appendices D, F and G (for certain gas-fired units) are used to determine the hourly SO_2 and CO_2 mass emission rates and heat input rates. For oil and gas-fired peaking units that use Appendix E to account for NO_X emissions, the hourly NO_X emission rates in lb/mmBtu are derived from a graph of NO_X emission rate versus heat input rate, the hourly heat input rates being derived from the applicable equation in Appendix F. Under § 75.54(b)(2), unit operating time is reported by rounding the actual operating time up to the nearest 15 minutes.

The equations in Appendices D through G assume that each unit operating hour consists of a full 60 minutes of unit operation (or, for common stacks, that emissions are discharged through the stack for 60 minutes in each hour); the equations do not attempt to account for partial unit operating hours. This is a shortcoming in the current rule, because partial unit operating hours sometimes occur during periods of unit startup, shutdown, and malfunction. Therefore, to ensure accurate accounting of SO_2 and CO_2 mass emissions and unit heat input, part 75 should address the issue of partial unit operating hours. Note, that because NO_X emission rates are measured with respect to heat input (lb/mmBtu), rather than with respect to time (lb/hr), this discussion is not relevant for NO_X emission rate. Many vendors and utilities have asked EPA for guidance on how to calculate mass emission rates during partial unit operating hours (see, e.g., Docket A–97–35, Item II–D–4).

The crux of the partial unit operating hour issue is when to adjust the emission data for unit operating time, before the reporting of hourly values or at the quarterly summation. For many units, there are very few hours of partial operation, and adjusting the data for operating time merely involves multiplying by 1, a seemingly inconsequential issue. For other units, such as peaking and cycling units, which start up and shut down often, the issue of how the data is reported is relevant because there can be a significant amount of partial unit operating hours. Definitive and standardized reporting requirements allow facilities and/or vendors to program their software such that their calculated result equals the result calculated by EPA.

For SO_2 and CO_2, the question is whether to report hourly emissions on a mass basis (i.e., lb or tons) or on a mass emission rate basis (i.e., lb/hr or tons/hr). For heat input, the question is whether to report the total hourly heat input (in mmBtu) or the hourly heat input rate (in mmBtu/hr). For example, suppose that a unit emits for a full 60 minutes in a particular clock hour at an SO_2 concentration of 602.5 parts per million (ppm), a CO_2 concentration of 10.0 percent, a volumetric flow rate of 4,000,000 standard cubic feet per hour (scfh), and a heat input rate of 300 mmBtu/hr. Suppose further that the same unit operates for only 15 minutes in the next hour and all of the parameters (i.e., SO_2 and CO_2 concentration, flow rate, and heat input rate) remain unchanged. If unit operating time is disregarded, the SO_2 mass emission rate (calculated from Equation F–1 in Appendix F) would be the same (400 lb/hr) for both the partial operating hour and the full unit operating hour. Similarly, the CO_2 mass emission rate would be the same (22.8 tons/hr) and the heat input rate would be the same (300 mmBtu/hr) for both the full and partial operating hours. The mass emission rates and heat input rate for the partial unit operating hour are the same as the full-hour values because they are based solely upon data recorded during unit operation, i.e., in the first 15 minutes of the hour. The hourly average rates for the partial hour do not include ''zero'' values for the three 15-minute periods of unit non-operation during the clock hour (e.g., an SO_2 emission rate of (400 lb/hr + 0 + 0 + 0)/4 = 100 lb/hr would not be appropriate). If the emission and heat input rates are adjusted by multiplying them by the operating time, then, for the full operating hour (i.e., operating time = 1.0), the SO_2 and CO_2 mass emissions and heat input would be, respectively, 400 lb SO_2, 22.8 tons CO_2, and 300 mmBtu. For the partial hour (operating time = 0.25), the corresponding values would all be divided by four, i.e., 100 lb SO_2, 5.7 tons CO_2, and 75 mmBtu, respectively.

Software vendors and utilities have requested clarification as to whether hourly SO_2 mass emission values should be reported as totals, in lb, or as rates, in lb/hr. As early as November of 1993, EPA stated that hourly SO_2 mass emission values should be reported as rates in lb/hr. Then, when determining quarterly cumulative SO_2 mass emissions, each hourly emission rate would be converted to a mass basis by multiplying it by the unit operating time (expressed as a fraction of an hour) for the same hour. Similarly, hourly heat input values would be expressed as rates, in mmBtu/hr, and hourly CO_2 mass emissions would be expressed as rates, in tons/hr. Parallel issues were also addressed by the Agency's policy, for units that determine SO_2 and CO_2 mass emissions and heat input from fuel flow rates and fuel analyses under Appendix D to part 75 (see Docket A–97–35, Item II–I–9, Policy Manual, Questions 14.14, 14.36 and 14.37).

Some utilities have requested that the Agency change its policy and allow reporting of hourly total SO_2 and CO_2 mass emissions and heat input instead of mass emission rates and heat input rates (see Docket A–97–35, Item II–E–14). The utilities argued that this would simplify determination of the total year-to-date SO_2 mass emissions, in order to estimate the number of allowances needed to cover a unit's emissions or to prepare a report on mass emissions for a state environmental agency, because the reported values would already be multiplied by the hourly operating time. Thus, by performing the multiplication by operating time before reporting the hourly value rather than waiting until calculating the quarterly value, it might save a calculation step if a facility wanted to use the data for another purpose. For these reasons, reporting of totals is a preferred approach for some facilities. However, other utilities that have incorporated the correct rate approach into their software have indicated that they would prefer not to have to revise their software to report in totals.

Partial unit operating hours must also be considered in the recording and reporting of hourly unit load. The standard missing data procedures in § 75.33 require historical flow rate data to be placed in load ''bins'' (ranges) based upon the maximum operating electrical generation (or steam flow rate) of the unit. However, the recorded hourly volumetric flow rate value in scfh applies only to the fraction of the hour in which the unit operates. Therefore, the reported load for the hour should be based upon the average electrical generation during the period when the unit operates. Thus, the electrical generation should be recorded as a rate for the period when the unit operates, rather than an integrated total for the entire hour. The units for reporting hourly load should, therefore, be MWe or 1000 lb/hr of steam, and not MW-hr or 1000 lb of steam.

Discussion of Proposed Changes

In today's rulemaking, EPA is proposing to amend part 75 to clarify that heat input, fuel flow, SO_2 mass emissions, and CO_2 mass emissions are all to be reported on an hourly basis as rates. Today's proposal also would clarify that the hourly emission rates are to be based only upon data collected during periods of unit operation (i.e., for partial unit operating hours, emission rates or heat input rates of zero that are recorded during periods of non-operation are not to be included in the hourly average emission rates). These clarifications are found in proposed § 75.57, and Appendices D, E and F to part 75. Today's proposed rule would also clarify that the proper units of reporting for load are MWe and lb/hr of steam.

Today's proposal would also provide new options for reporting unit operating time. While the current requirement to report operating time rounded to the nearest 15 minutes would be retained as an option, the proposal would allow more flexibility by specifying that, for reporting purposes, unit operating time be 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).

Consistent with the requirement to report hourly SO_2 and CO_2 mass emissions and hourly heat input as rates, today's rulemaking proposes to revise the quarterly summation formulas for SO_2 and CO_2 and to add summation formulas for heat input in Appendix F to part 75. The proposed formulas show that hourly mass emission rates or heat input rates would be multiplied by unit operating time before summing to get total mass emissions. Today's proposal also includes new formulas in Appendix D for summing hourly SO_2 mass emission rates and hourly heat input values from fuel flowmeter systems in order to determine quarterly and annual total SO_2 mass emissions and total heat input. The Appendix D and F equations revised or added to address summations include Equations D–6, D–7, D–8, D–9, F–3, F–12, F–24, and F–25.

In addition, EPA is proposing optional recordkeeping provisions for determining total heat input, total SO_2 mass emissions or total CO_2 mass emissions for the hour. In addition to reporting the required emission and heat input rates, owners or operators could choose to report the total hourly heat input and mass emissions under this option.

Rationale

As stated above, some utilities have expressed a preference for reporting hourly total values for SO_2 and CO_2 mass emissions and heat input, rather than rates (see Docket A–97–35, Item II–E–14). They have stated that this is easier to understand and that reporting hourly total values, instead of or in addition to rates, would make it easier to determine the cumulative total mass emissions at any time during the year.

One representative requested that EPA consider allowing either method of calculation (i.e., hourly rates or totals), so long as the annual mass emissions and heat inputs are correctly determined and reported. EPA notes that, although this approach may appear advantageous because it would not require some facilities to reprogram their DAHS software, it would require other facilities to reprogram their software and it would make it difficult for EPA to verify emissions calculations from reported hourly data. Because EPA considers it essential to the Acid Rain Program to be able to recalculate annual compliance values based upon hourly emission information reported by facilities, the Agency is not revising the rule to take the representative's suggestion. EPA considered using the total mass emissions (or total heat input) approach instead of the mass emission rate (or heat input rate) approach currently stated in Agency policy (see Docket A–97–35, Item II–I–9, Policy Manual, Questions 14.14 and 14.36). In fact, as discussed in section III.H. of this preamble, the Agency is proposing, under subpart H of part 75, model reporting requirements for NO_X mass emissions that would (if adopted by an applicable state or federal authority) require hourly NO_X mass emissions to be reported as a total value (in lb) rather than an hourly mass emission rate (in lb/hr). However, using hourly mass emission totals for values currently reported to the Agency would have the distinct disadvantage of requiring both EPA and the utilities who correctly implemented the mass emission rate approach to reprogram software to perform the new calculations, whereas retaining the use of SO_2 and CO_2 emission and heat input hourly rates offers several advantages.

First, using hourly mass emission rates and heat input rates instead of totals is consistent with the units of measure in which flow rate is recorded. Volumetric flow monitors measure flow rate during a given time in standard cubic feet per hour scfh, rather than total flow in standard cubic feet (scf). When SO_2 concentration is multiplied by volumetric flow rate, one calculates a mass emission rate rather than a total mass of SO_2. Similarly, multiplying a volumetric flow rate by a diluent gas concentration yields a heat input rate in mmBtu/hr, rather than a total heat input in mmBtu.

Second, the current missing data procedures for volumetric flow rate, which are based upon the assumption that flow is a rate that is comparable from one hour to another, rather than a total volumetric flow that will vary depending upon the unit operating time, would no longer be appropriate if volumetric flow rate were changed to a total volumetric flow. Third, for Appendix E gas-fired or oil-fired peaking units, it is critical that heat input rate, and not total heat input, be used to determine the NO_X emission rate. The Appendix E correlation curve formulas are based upon heat input rate rather than total heat input. Appendix E allows a facility to create a correlation of the NO_X emission rate measured in the stack during stack testing and heat input combusted during that same period of time, rather than installing CEMS on gas-fired or oil-fired peaking units. If a facility were mistakenly to use the total heat input from an hour rather than the heat input rate, it would correlate to the wrong portion of the NO_X to heat input rate correlation curve and would incorrectly estimate NO_X emission rate. For example, if heat input totals were used to determine NO_X emission rate from the Appendix E curve, the unit would have a different NO_X emission rate if it combusted 25,000 mmBtu in half an hour than if it combusted 25,000 mmBtu during a full hour. This would apply both under the current provisions of Appendix E and today's revised provisions to Appendix E.

In view of the above considerations, today's proposed rule would affirm that facilities are to report SO_2 and CO_2 emissions and heat input as rates on an hourly basis. However, facilities would also be allowed, at their discretion, to report SO_2 and CO_2 emissions and heat input as hourly totals, in addition to reporting them as rates. This approach would not require reprogramming of computerized reporting software for those utilities that are following EPA's current policy, and would provide consistent reporting that allows EPA to recalculate emissions and heat input values. Those utilities that find recording and reporting of hourly total SO_2 and CO_2 mass emissions and heat input to be desirable would be able to do so. EPA will provide the necessary electronic record types to support this optional reporting.

Although today's proposed rule would affirm that emissions and heat input are to be reported as rates, rather than totals, EPA has become concerned that for partial unit operating hours, some utilities are incorrectly calculating hourly average flow rates by including flow rates of zero in the hourly average to represent periods of non-operation, rather than basing the average flow rate solely on the minutes of operation of the affected unit during the clock hour. In one example, it appears that the software is designed to calculate the average flow rate by including data from all minutes during those fifteen-minute quadrants of an hour when the unit operates, thus including some minutes when the unit is not operating, rather than creating an average flow rate just from merely those minutes when the unit is operating and emitting (see Docket A–97–35, Item II–C–17). EPA suspects that still other utilities may be calculating an average hourly flow rate that includes flow rates of zero for whole quadrants of an hour when a unit does not operate. This can result in the flow rate values for partial operating hours being under-reported to EPA and a lowering of the average flow rates in the load ranges used to provide substitute flow rate data, both of which can cause underestimation of SO_2 mass emissions.

The Agency is also concerned that this same kind of improper data averaging may be occurring when hourly gas concentrations are determined during partial operating hours. EPA would, therefore, require in today's proposal that facilities base all of their reported hourly average concentrations, flow rates, emission rates, and heat input rates solely upon data that are recorded during unit operation (that is, when the unit is combusting fuel and emitting).

Some utilities have indicated that the approach of averaging in readings of zero from periods of non-operation has been incorporated to compensate for having to report operating time rounded up to the nearest fifteen minutes (Note, this is not an acceptable approach). A utility representative indicated that reporting operating time to less precision can cause overestimation of emissions because the operating time is multiplied by the mass emission rate. Thus, a mass emission rate of 400 lb/hr measured over a period of 20 minutes, during an hour when the unit shut down, would be multiplied by an operating time of .5 hr (i.e., 20 minutes rounded up to the nearest fifteen minutes) and would result in 200 lb of SO_2 being reported rather than the 132 lb of SO_2 that was actually emitted. The utility suggested that a solution would be to allow operating time to be reported to more precision than is currently allowed. Therefore, today's proposal would allow flexibility for reporting unit operating time to greater precision. While the current requirement to report operating time rounded up to the nearest 15 minutes would be retained as an option, the proposal would allow more flexibility by specifying that unit operating time be 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). Thus, a facility could decide whether it had enough partial operating hours (e.g., unit start-ups and shutdowns) to merit changing their software to report operating time to more precision.

2. Use of Bias-Adjusted Flow Rates in Heat Input Calculations.

In late 1995, the first year of the Phase I SO_2 allowance program, EPA conducted an audit of the Phase I-affected units. Data from the second quarter of 1995 were retrieved from the Emission Tracking System (ETS) in order to determine whether the SO_2 emission rates and heat input values were being properly reported. The results of the audit showed that a number of sources were not reporting heat input correctly. The problem in most instances was that the unadjusted flow rate was being used in the heat input equation, rather than the bias-adjusted value. EPA believes that this is attributable to the fact that part 75 does not explicitly state that the bias-adjusted flow rate is to be used in heat input calculations. The Agency has attempted to clarify this through policy guidance (see Docket A–97–35, Item II–I–9, Policy Manual, Question 14.81). To correct the situation, the necessary language would be added to section 7.6.5 of Appendix A in today's proposed rule.

3. Removing the Restriction on Using the Diluent Cap Only for Start-Up

Background:

Based on the May 17, 1995 direct final rule, sections 3.3.4, 4.1, 4.4.1, 5.1, 5.2.1, 5.2.2, 5.2.3, and 5.2.4 of Appendix F currently provide for the substitution of a constant CO_2 or O_2 value for a measured value from a CO_2 or O_2 monitor during unit start-up. This provision was originally created in response to concerns from some utilities that their NO_X emission rate in lb/mmBtu was being overestimated during unit start-up (see Docket A–90–51, Item IV–D–220, Letter from English, Mark G., Deputy General Counsel, Kansas City Power & Light Company on EPA's Proposed Part 75 regulations; see also Docket A–94–16, Item II–F–2). During unit start-up or other periods when the unit is at a low load level, CO_2 concentrations are lower than during normal operation and O_2 concentrations are higher than during normal operation. The NO_X emission rate equation, however, is not designed to be used in these situations because it assumes complete combustion and normal operating conditions. As a result, the NO_X emission rate equation overestimates the NO_X emission rate when the CO_2 concentration is very low or the O_2 concentration is very high, such as during start-up. The equations for calculating emission rates in lb/mmBtu use measured CO_2 concentration or the difference between ambient air's O_2 concentration and the measured O_2 concentration in the denominator. For example, NO_X emission rate is calculated using a NO_X pollutant concentration monitor and a CO_2 diluent monitor using the following equation:

$$E_{NO_X} = 1.194 \times 10^{-7}\ C_{NO_X}\ F_c \frac{100}{\%CO_2}$$

When a small CO_2 concentration is entered into this equation, the calculated NO_X emission rate will be very high and will overestimate the actual emissions.

The idea of capping CO_2 or O_2 concentration was implemented in part 75 for determination of NO_X emission rate, CO_2 mass emissions, and heat input during unit start-up. The cap concentration was set at a minimum CO_2 concentration of 5.0 percent CO_2 and a maximum O_2 concentration of 14.0 percent O_2, based upon some information provided by utilities for boilers (see Docket A–94–16, Item II–D–34).

Some utilities asked EPA to consider extending this cap on diluent gas concentrations to other situations when a unit is operating at a low level (see, e.g., Docket A–97–35, Items II–D–20 and 30, and Docket A–97–35, Items II–E–13 and II–E–14). In addition to unit start-up, this might include periods of unit shutdown or unit "banking," where a unit is combusting a very small amount of fuel to keep the boiler warm, but little or no electricity is generated. During these other situations where a unit operates at a low level, the CO_2 concentration will be very low and the O_2 concentration will be very high, resulting in high calculated NO_X emission rate values like those during unit start-up. One software vendor specifically mentioned that it would be easiest to implement the diluent cap if it could be used any time the CO_2 concentration would fall below or the O_2 concentration would rise above the cap value (see Docket A–97–35, Item II–E–7). This could be implemented mathematically in the software, rather than having to examine the unit operation or the number of hours since the unit started operating in order to trigger use of the diluent cap.

During the process of implementing the May 17, 1995 direct final rule, EPA issued guidance that explained that facilities may use the diluent cap values for calculating NO_X emission rate during unit start-up whenever the CO_2 concentration is below 5.0 percent or the O_2 concentration is above 14.0 percent, and also may use the actual measured CO_2 or O_2 concentration values at all times for calculating CO_2 mass emissions or heat input (see Docket A–97–35, Item II–I–9, Policy Manual, Question 14.39). In Question 14.39, EPA recommended that even if the diluent cap is used to calculate NO_X emission rate, the actual diluent measurement should be used for the purpose of calculating CO_2 mass emissions or heat input, because the purpose of the diluent cap was "to avoid using an extreme diluent concentration in the denominator of the equation to calculate emission rate in lb/mmBtu." The formulas for calculating hourly CO_2 mass emission rate or hourly heat input rate do not use the CO_2 or O_2 concentrations in the denominator of the equation. Thus, use of the diluent cap would tend to overestimate both CO_2 mass emission rate and hourly heat input.

Discussion of Proposed Changes

Today's proposed rule would allow facilities to use diluent cap values of 14.0 percent O_2 or 5.0 percent CO_2 for boilers and 19.0 percent O_2 or 1.0 percent CO_2 for turbines. For the purpose of calculating NO_X emission rates in lb/mmBtu, the diluent cap would be allowed to be used for any hour in which the average measured CO_2 concentration is below the cap value or the average measured O_2 concentration is above the cap value. Diluent cap values would still be allowed to be used to calculate CO_2 mass emissions or heat input, as well as NO_X (or SO_2) emission rate in lb/mmBtu.

Rationale

EPA acknowledges that there are periods of low unit operation or low load in addition to unit start-up where the calculated NO_X emission rate would be overestimated if it were based upon measured diluent concentrations. Therefore, the Agency believes that extending use of the diluent cap is appropriate. The Agency believes that allowing use of the diluent cap anytime when the actual measured value is above the cap (for O_2) or below the cap (for CO_2) is easier to program and to implement than limiting the use of the diluent cap based upon unit load, another option that EPA considered. The Agency believes that it is unlikely that a unit would ever be able to operate at a high load and still have an O_2 or CO_2 concentration beyond the diluent cap value. Therefore, it is not necessary to limit the use of the diluent cap value based on unit load.

The Agency is also proposing new diluent cap values for turbines. Turbines tend to operate with much higher levels of excess O_2 than boilers. For example, Method 20 of Appendix A, 40 CFR part 60, the procedure for testing SO_2, NO_X and diluent gas from stationary gas turbines subject to the NSPS, requires testers to correct data to a typical concentration of 15.0 percent O_2. Emissions data reported to EPA confirms that for turbines, hourly concentrations of O_2 are typically between 14.0 and 16.0 percent and hourly concentrations of CO_2 are typically between 3.0 and 4.0 percent. Thus, a turbine's diluent gas concentration is likely to consistently exceed the diluent cap value of 14.0 percent O_2 and to be consistently below the cap value of 5.0 percent CO_2 promulgated in the May 17, 1995 direct final rule. If these values were allowed to be used by turbines at all times rather than just during unit start-up, a turbine could conceivably report its NO_X emission rate using only the diluent cap value and never report the actual monitored diluent concentrations, thereby consistently underestimating the NO_X emission rate. Therefore, today's proposal provides diluent cap values of 19.0 percent O_2 or 1.0 percent CO_2 that are clearly beyond the typical O_2 or CO_2 concentrations measured at turbines, while still providing some relief at extreme diluent concentrations. It is EPA's observation that turbines with NO_X CEMS have not reported emissions using the diluent cap thus far. Thus, no turbines should need to reprogram software in order to report the use of the new diluent cap value for turbines with a new method of determination code.

EPA considered removing the option for facilities to use the diluent cap for heat input rate and CO_2 concentration, as well as for NO_X (and SO_2) emission rate in lb/mmBtu, but is not proposing to do so in today's proposal. As explained previously, the diluent cap was created in order to calculate more representative NO_X emission rate data during certain unusual circumstances. However, when a diluent cap value is used to calculate the hourly CO_2 mass emission rate or the heat input rate, the final calculation would often be less representative of actual emissions or heat input during those hours. The Agency also found that allowing some facilities to use the diluent cap only for NO_X emission rate and others to use the diluent cap also for hourly CO_2 mass emission rate and heat input rate makes it difficult to check emissions and heat input rate data to verify that calculations are performed correctly. This is because a data acquisition and handling system could use either the actual reported diluent gas concentration or the diluent cap value to calculate NO_X emission rate, CO_2 mass emission rate, or heat input rate, but there is currently no provision in the electronic data reporting format for a facility to indicate which value was used to calculate the heat input. However, some utilities have indicated that making a change to discontinue using the diluent cap for calculations of heat input rate and CO_2 mass emission rate would require a significant change in their software calculations (see Docket A–97–35, Item II–E–25). Therefore, today's proposed rule would allow facilities the options of (1) not using the diluent cap at all, (2) using the diluent cap only for calculating NO_X (or SO_2) emission rate in lb/mmBtu, or (3) using the diluent cap for calculating NO_X (or SO_2) emission rate in lb/mmBtu, heat input rate, and CO_2 emissions. In addition, EPA is proposing to add a minor additional reporting requirement to indicate whether the diluent cap is used in calculating CO_2 and heat input in the electronic data reporting format. This would allow EPA to verify facilities' calculations, while requiring less reprogramming than changing the calculations for heat input and CO_2 emissions.

The Agency solicits comment on the proposed revisions relating to the diluent cap.

4. Complex Stacks—General Issues

Background

Many power plants regulated under part 75 have relatively simple stack and monitoring configurations. Many utilities have one stack for each affected unit and have CEMS installed on the stack. Other plants have more than one unit discharging to the atmosphere through a common stack, with CEMS installed on the common stack. Still others have individual units that exhaust into multiple stacks and have CEMS installed on each stack. The monitoring requirements for these various configurations are addressed in §§ 75.13, 75.16, 75.17, and 75.18. EPA has issued guidance to assist utilities in preparing quarterly reports for these unit and stack configurations (see Docket A–97–35, Items II–I–4 and II–I–9, Policy Manual, Section 17).

For the configurations described above, the process of accounting for emissions and heat input from the units and stacks will follow simple mathematical rules. For example, for single unit-single stack configurations, the emissions and heat input for the unit are directly determined from the stack CEMS (or from an excepted methodology, where applicable). For units discharging through a common stack with CEMS on the common stack, the combined emissions and heat input are determined from the CEMS, and the heat input to each individual unit is determined by apportionment of the combined heat input, using a ratio of the unit load to the combined load of all units utilizing the common stack. For a single unit exhausting through multiple stacks, the sum of the SO_2 and CO_2 mass emissions and heat input for the different stacks equals the total SO_2 and CO_2 mass emissions and heat input for the unit.

However, in implementing part 75, EPA has become aware of a number of affected units that have stack exhaust configurations which are more complex than the configurations described above. For example, one utility has a configuration in which two units can emit through two different stacks at the same time, combining their emissions in both stacks (see Docket A–97–35, Items, II–C–1, II–D–12). In this case, the stack configuration is both a common stack and a multiple stack configuration. EPA has had significant problems in determining the emissions and heat input from these units, and in one case, EPA rejected the quarterly reports for the units (see Docket A–97–35, Item II–C–8). The utility worked closely with EPA to resolve the reporting issues resulting from this unusual situation (see Docket A–97–35, Item II–D–21). Other utilities with similar situations have contacted the Agency to ensure there would not be problems with their reporting (see, e.g. Docket A–97–35, Item II–D–5).

There have been other cases in which a unit that is accountable for holding SO_2 allowances shares a common stack with a unit that does not hold SO_2 allowances (e.g., where an affected unit and a non-affected unit share a common stack or, prior to 1/1/2000, where a Phase I unit and a Phase II unit share a common stack). These are termed ''subtractive stack'' situations in the following discussion. Utilities with subtractive stack situations have generally used the provisions of § 75.16(a)(2)(ii)(C) or § 75.16(b)(2)(ii)(B). These provisions allow a facility to monitor separately the common stack and the unit with no allowance requirement and to subtract the emissions from the non-affected or Phase II unit from the common stack emissions. In some cases, it has not been clear in the electronic quarterly reports whether a utility is reporting combined emissions from all of the units using the common stack or whether the emissions from the non-affected unit(s) have already been subtracted out of the reported emissions (see Docket A–97–35, Item II–C–18). This confusion in interpreting the quarterly emissions reports has made compliance determination difficult.

The Agency found that there is a potential problem with the underestimation of emissions using this subtractive approach. In some cases, the error in the monitors' measurements might be such that a larger emissions value is subtracted from a smaller value, resulting in the reporting of false negative emissions (see Docket A–97–35, Item A–94–16–IV–D–18, Comments from Monitor Labs). In other cases, there may be an incentive for making inaccurate measurements with the monitoring systems installed on a unit with no allowance requirement. For example, if the SO_2 pollutant concentration monitor on a unit with no allowance requirement did not operate properly and had a significant amount of missing data, the facility would calculate SO_2 emissions from the unit using a conservative, high concentration value. Therefore, emissions reported for the units with allowance requirements would, as a result of the subtraction, be less than the actual emissions. Thus, a facility might have a disincentive for good monitor performance and accuracy, because it could lower the emissions reported for the units with allowance requirements. Though allowed under the current wording of Appendix A to part 75 and subpart D of part 75, this is contrary to the intent of the missing data substitution procedures, which is to encourage good monitor performance while preventing any systematic underestimation of emissions. (See Docket A–97–35, Items II–B–13, II–E–4, and II–I–12.)

Discussion of Proposed Changes

Today's proposed rulemaking would add a general regulatory requirement to §§ 75.16 and 75.17 for facilities with complex stack configurations (i.e., subtractive stack situations or configurations involving combinations of common stacks and multiple stacks) to receive approval from EPA's Administrator for a method of calculating and reporting emissions from the units and stacks in the configuration. The facility would be required to reach agreement with the Agency on issues such as: identification of the stack in its quarterly report, representation of the configuration in its monitoring plan, groups of units for which cumulative emissions must be reported, testing procedures, use of the bias test, and use of the missing data substitution procedures. This would apply both to sources that already have certified monitoring equipment and are submitting quarterly reports and to units that do not yet have certified monitoring systems (e.g. new units).

Rationale

The Agency evaluated two basic approaches to resolving issues in these complex stack monitoring configurations. First, EPA considered resolving the issues through policy guidance and through instructions for submitting quarterly reports. Second, the Agency considered putting detailed instructions in part 75 for reporting from and testing of monitoring systems installed in these complex stack configurations. These rule provisions would have explicitly addressed missing data substitution to ensure that when emissions are reported, they are not underestimated from units with an allowance requirement or a NO_X emission limitation. For example, EPA could have required, for the subtracted unit(s), that the facility only use those provisions of the standard missing data procedures that are not intended to be conservative estimates, such as the average SO_2 concentration during the hour before and the hour after a missing data period. Another approach for missing data substitution could have been to count zero emissions for the unit with no allowance requirement during any missing data periods. Or perhaps creation of a site-specific missing data procedure could have been required (see Docket A–97–35, Items II–E–4 and II–I–12). To prevent a potential underestimation of emissions and a disincentive for more accurate monitoring due to application of a bias adjustment on a monitor on a unit with no allowance requirement where its emissions are subtracted from a common stack, EPA could have required that the bias calculation be based upon both the monitors on the common stack and the monitors on units with no allowance requirement, resulting in a single bias adjustment factor for the subtractive stack situation.

However, EPA's experience thus far in implementing the program indicates that each complex monitoring configuration tends to be unique. Thus, the Agency has rejected the two approaches discussed above and has decided instead to make General regulatory revisions that allow for case-by-case resolution of issues in individual plant situations, rather than making extensive, detailed revisions to part 75 to address each unique situation.

The Agency prefers to make regulatory revisions rather than addressing issues solely through policy and guidance. In some cases, the Agency has given advice to utilities on how to report emissions, and the utility involved has not followed the Agency guidance (see Docket A–97–35, Items II–C–7, II–C–24, and II–D–8). In another case, the current provisions of part 75 for missing data substitution and for the bias test appeared to be in conflict with guidance that the Agency wanted to issue in order to ensure that emissions are not underestimated in a subtractive stack situation (see Docket A–97–35, Item II–B–13). Therefore, today's proposed rule would require owners or operators of facilities with complex stack configurations to apply for approval of their monitoring plans and reporting methodologies from EPA's Administrator on a case-by-case basis. The Agency believes that the General regulatory provisions requiring approval of a complex monitoring situation by EPA's Administrator will give both facilities and the Agency flexibility to deal with site-specific cases, while also giving the Agency regulatory authority to resolve any case-specific problems.

It is possible that any final rule resulting from today's proposal may not be promulgated until 1999. Thus, EPA is proposing to require the Administrator's approval of the monitoring plans and reporting methodologies only for those situations that will exist on and after January 1, 2000. Any subtractive stack situations that exist only during the duration of Phase I would not fall under this requirement. However, complex stack situations that exist where affected and non-affected units share a common stack would need to meet today's proposed requirement. Similarly, in situations where coal-fired units sharing a common stack have different NO_X emission limitations under part 76, or situations where some units sharing a common stack have a NO_X emission limitation under part 76 and others have no NO_X emission limitations under part 76, any complex monitoring configuration would need to be approved by EPA's Administrator.

5. Complex Stacks—Heat Input at Common Stacks

Background

For a unit that utilizes a flow monitor to determine SO_2 mass emissions, section 5 of Appendix F to part 75 requires heat input to be calculated using the installed flow monitor and a diluent gas (O_2 or CO_2) monitor. The January 11, 1993 final rule indicated that units with common stacks, multiple stacks, or bypass stacks should follow the same General procedures for monitoring heat input as are used for monitoring SO_2 under § 75.16. As written, those procedures allowed facilities to monitor their heat input either by placing individual monitors on each unit that serves a common stack or by placing monitors only on the common stack and measuring a combined heat input from all of the units sharing the common stack. The May 17, 1995 rule required the combined heat input measured by monitors on the common stack to be apportioned to the individual units, in two specific provisions. First, unit level heat input was required under § 75.16(e)(2) for cases in which a knowledge of the heat input for each unit is critical to compliance determination (i.e., for situations where any units using the common stack have a NO_X emission limit). Second, § 75.16(e)(3) required unit level heat input to be determined for all other common stacks, but only until the year 2000. The November 20, 1996 rule outlined the acceptable methodology for apportioning heat input, i.e., by using the ratio of the unit load in MWe or lb of steam per hour to the combined load of all units utilizing the common stack (provided that all of the units utilizing the common stack are combusting fuel with the same F-factor).

Discussion of Proposed Changes

Today's proposed rule would revise the existing requirements found in § 75.54(b) and two specific provisions of § 75.16(e) for accounting of heat input for units serving a common stack, a by-pass stack, or multiple stacks. First, EPA would require determination and reporting of the unit level heat input to be continued after the year 2000 for all affected units, rather than restricting it to certain situations after 2000. Second, EPA would clarify that the proper units of measure for load to be used in an apportionment of common stack heat input to determine unit level heat input are totals of MWe-hr and 1000 lb of steam, rather than rates of MWe and 1000 lb/hr of steam.

Rationale

EPA considered leaving the current provisions of § 75.16(e) and § 75.54(b) from the May 17, 1995 and November 20, 1996 rules unchanged. However, this would have the serious drawback of requiring the facilities to reprogram their computer software for certain units and not for others. Corresponding monitoring plan changes would also be required. Additionally, EPA would have to reprogram its emission tracking software to accommodate two different heat input reporting methodologies for common stacks. In view of these considerations, EPA is proposing to continue to receive individual heat input data from all affected units. This information is useful for developing inventories of total NO_X mass emissions in tons in support of other Agency rulemakings. Without such information, the inventories would be based on assumptions about how units operate, rather than being based on unit level heat input as reported from the facility.

The Agency believes that a relatively small number of sources would be affected by this proposed change. This is because (1) most coal-fired units would still need to report unit level heat input under the current provisions of § 75.16(e)(2), even after the year 2000; and (2) gas-fired and oil-fired units using fuel flowmeters to determine heat input and to implement the procedures of Appendix D or Appendix E would still be required to monitor heat input for each unit under section 2.1 of Appendix D. Because of the usefulness of having heat input data for individual units, because of the burden of reprogramming software to remove the heat input apportionment by the year 2000, and because of the small number of sources that would benefit from retaining the current provisions of § 75.16(e)(3), EPA believes it is reasonable to require all units that measure combined heat input at a common stack to continue to apportion heat input to the individual units. The Agency solicits comment on the number of sources that would be affected by this revision.

6. Start-Up Reporting—Units Shutdown Over the Compliance Deadline

Background

As currently written, part 75 requires that units which are shutdown over an applicable compliance date specified in § 75.4 must submit a notice of the planned and (if different) actual shutdown date. In addition, § 75.4(d) provides an extended certification deadline for such units of ''the earlier of 45 unit operating days or 180 calendar days after the date that the unit recommences commercial operation of the affected unit.'' If an owner or operator subsequently recommences commercial operation of the unit, a notice related to the planned and (if different) actual date of recommencement of commercial operation is required. In addition to these notices, § 75.64 requires that after the applicable compliance date passes, the owner or operator must submit quarterly reports for such units. If the unit remains shut down and does not operate during the quarter, the quarterly report must show zero emissions. Utility commenters (see, e.g., Docket A–97–35, Items II–D–20, II–D–30) have recommended that this quarterly report requirement for shutdown units be deleted because it is unnecessary and burdensome.

Discussion of Proposed Changes

Section 75.64(a) would be modified so that quarterly reporting is not required until the first quarter in which a previously shutdown unit recommences commercial operation. In this case, the first quarterly report would contain data beginning with the hour in which the unit recommences commercial operation.

Rationale

Units that are shutdown over their applicable certification deadlines are required to submit notice, pursuant to § 75.61(a)(3), of the planned date of recommencement of commercial operation and also must submit a follow-up notice if the actual date of recommencement of commercial operation is different from the planned date. As a result of these notice provisions, EPA will know whenever the status of a shutdown unit changes. Because shutdown units have no emissions, the Agency believes that quarterly reporting in addition to the notice provisions is unnecessary to fulfill the emission reporting objectives of the Act.

The Agency notes, however, that the proposed revision differs from that suggested by certain utilities (see Docket A–97–35, Item II–D–30). The utilities proposed tying the reporting requirement to the certification deadline in § 75.4(d). However, under § 75.4(d), facilities are required to report emissions data using special provisions in that section prior to the extended certification deadline in § 75.4(d). Thus, the proposed revisions would tie the obligation for quarterly reporting to the quarter in which commercial operation is recommenced.

7. Start-Up Reporting—New Units

Background

As currently written, § 75.64(a) requires the first quarterly report for new units to be submitted for the quarter corresponding to the compliance date in § 75.4. However, the current provision is unclear about which hourly emissions data need to be included in the first quarterly report if the compliance deadline does not correspond to the first hour in the quarter.

Discussion of Proposed Changes

Section 75.64(a) would be modified to clarify that a new unit must start reporting data beginning with the earlier of the date and time of provisional certification or the compliance deadline in § 75.4(b).

Rationale

These proposed revisions are generally consistent with existing implementation of the new unit reporting requirements, and primarily would serve to clarify ambiguous elements of the current rule.

8. Recordkeeping and Reporting Provisions

Background

Subpart F and subpart G of the existing part 75 regulation set forth the recordkeeping and reporting requirements that accompany the monitoring provisions of part 75. Specifically, in subpart F, § 75.53 contains the monitoring plan requirements, § 75.54 contains the general recordkeeping provisions, § 75.55 lists the general recordkeeping provisions for specific situations, and § 75.56 consists of the certification, quality assurance and quality control record provisions. In subpart G, § 75.62 lists the monitoring plan reporting provisions, § 75.62 contains the reporting requirements for initial certification and recertification applications, and § 75.64 discusses the provisions for quarterly reports. Quarterly reports are electronic data files containing emissions and operating data from affected units, as well as monitoring plan information and the results of certification and quality assurance tests. Under § 75.64, these electronic data reports are required to be submitted to the Agency each calendar quarter. This electronic information is used by the Agency for many different purposes, including implementation of the SO_2 allowance trading program, determination of compliance with emission limits, development of reports on utility emissions, and modeling of air quality to assess the effectiveness of the Act.

In order to effectively use the electronic quarterly report information, EPA created a standardized reporting format, the electronic data reporting (EDR) format. The electronic file formats and record structures of the EDR provide the vehicle by which required information is submitted to the Agency every calendar quarter. The EDR primarily defines the order, length, and placement of information within the electronic report or file. The individual tables of the EDR define the record type, type code, start column, data element description, units, range, length, and FORTRAN format for each data element in the electronic report. The information in the EDR fields mirrors the required information set forth in subparts F and G of part 75. Considering both the volume of information contained in each quarterly report (e.g, operating and emissions data for each of the hours in the quarter) and the number of reports submitted to the Agency (i.e., currently, 1765 reports are received each quarter for the 2055 affected units; some reports contain information for more than one unit if several units are interrelated, as in a common stack configuration), a standard format is critical in order for the Agency to review, verify, and use the information reported. A standard format allows the Agency to develop software to receive and verify the files and to correlate and separate out specific information for compliance determinations. A standard format also allows software vendors to create standard software which can be utilized by many affected units. This is more cost effective than developing site-specific software and thus reduces the software cost to industry.

Today's rulemaking proposes a number of revisions to subparts F and G of part 75 (the reporting and recordkeeping sections of the rule). The majority of these changes are necessary to implement the proposed substantive revisions to the sections of the rule and appendices discussed elsewhere in this notice. In addition, EPA is proposingrevisions to these subparts in order to streamline implementation of the program and to coordinate reporting under the Acid Rain Program with other programs.

To support the changes to the recordkeeping provisions, new §§ 75.57, 75.58, and 75.59 would be added. These sections would replace existing §§ 75.54, 75.55, and 75.56. The addition of new sections is necessary because the proposed revisions would not be mandatory until January 1, 2000, and to have the proposed revisions listed throughout existing effective sections could lead to confusion. However, an owner or operator would be free to follow the provisions of §§ 75.57, 75.58, and 75.59 before January 1, 2000, if he chooses to do so. In addition, the owner or operator would be required to satisfy, prior to January 1, 2000, the elements in these sections that support a regulatory option proposed in other sections of part 75 if the owner or operator elects to implement that option prior to January 1, 2000.

Because, as discussed above, the Acid Rain Program relies on a standardized electronic data reporting format, EPA has also developed draft revisions to the EDR formats and instructions (draft EDR version 2.1). The following discussion refers to both the rule sections and EDR record types (RTs) that would be affected by the proposed revisions.

Discussion of Proposed Changes

There are a number of proposed rule changes to the recordkeeping and reporting requirements of part 75 and corresponding draft EDR revisions that would be necessary to implement the substantive revisions proposed by EPA and discussed elsewhere in this preamble. These include the following requirements:

(1) Changes to support new CO_2 missing data requirements (see § 75.57 and RT 202, 210, and 211);

(2) Changes to support new reporting, QA and missing data requirements for moisture monitoring (see §§ 75.53, 75.57, and 75.59, and RT 211, 212, 220, and 618);

(3) Changes to support optional Appendix I (flow methodology for gas and oil units) (see §§ 75.57 and 75.58, and RT 220, 302, 303, 608, and 609);

(4) Changes to support more flexibility for units that have multiple range analyzers (see §§ 75.53 and 75.59, and RT 230, 530, 600, 601, and 602);

(5) Changes to support the use of the diluent cap during all hours (see § 75.57 and RT 300 and 330);

(6) Changes to support test exemptions and extensions for units that operate infrequently (see §§ 75.59 and 75.64, and RT 301, 697, and 698);

(7) Changes to support increased flexibility in fuel sampling (see § 75.58 and RT 302, 303, 313, and 314);

(8) Changes to allow reporting of hourly total values in addition to hourly rates (see § 75.57 and RT 300, 310, and 330);

(9) Changes to support the proposed re-definition of unit operating loads (see §§ 75.53 and 75.59, and RT 535 and 611);

(10) Changes to support reporting of conditional data during recertification events (see § 75.59, and RT 556);

(11) Changes to support a new quarterly flow-to-load QA check for flow monitors (see § 75.59, and RT 605 and 606);

(12) Changes to allow QA test grace periods (see § 75.59, and RT 699);

(13) Changes to support simplified reporting for low mass emissions units (see §§ 75.53, 75.58, and 75.63, and RT 360, 508, and 531);

(14) Changes to support fuel flow-to-load QA checks for fuel flow meters (see § 75.59, and RT 628 and 629); and

(15) Changes to support expanded reporting of RATA supporting information (see § 75.59, and RT 614, 615, 616, 617, and 618).

In addition, since the EDR version 1.3 was released, EPA has developed additional record types to aid in the implementation of the program, by allowing the designated representative to certify the validity of quarterly reports using an electronic certification statement. The proposed revisions would adopt the necessary rule language to implement these miscellaneous record types (see § 75.64, and RT 900, 901, 910, and 920).

The proposed revisions would also set forth optional requirements for reporting of NO_X mass emissions that states or EPA could adopt as part of a NO_X mass trading program, such as the OTC NO_X Budget Program. In this situation both a rule change and an EDR change would be needed (see §§ 75.57 and 75.64 and RT 301, 307, and 328).

The proposed rule revisions also include a number of changes that EPA believes will facilitate implementation of the program. These include:

(1) Reporting of test numbers, reasons for tests and indicators of aborted tests (see § 75.59, and RT 560, 600, 601, 602, 603, 610, and 611);

(2) Changing the deadlines for reporting the RATA supporting information that was originally required on January 1, 1998 (see § 75.59, and RT 614, 615, 616, 617, and 618);

(3) Reporting of an optional record type that will allow facilities to provide contact person information that many facilities currently provide in quarterly report cover letters (see § 75.59, and RT 999);

(4) Based on comments received, the rule would be revised so that reporting the reasons for missing data as part of the quarterly report would become optional, but would still need to be maintained on-site (see §§ 75.56 and 75.59, and RT 550);

(5) Reporting of facility location, identification, and EDR version numbers to support the transition from EDR 1.3 to EDR 2.1 (see § 75.64, and RT 100 and 102);

(6) Reporting of information documenting the calculation of heat input (see § 75.57, and RT 300);

(7) Reporting of reference method backup QA data (see § 75.59(a)(11), and RTs 260, 261, and 262);

(8) Expanded reporting of unit definition information (see §§ 75.53, and RTs 504, 585, 586, and 587);

(9) Reporting of Appendix E segment ID information (see § 75.58, and RT 323, 324, and 560);

(10) Reporting of qualification data for peaking units or gas-fired units (see § 75.53, and RT 507);

(11) Reporting of the qualifying test for off-line calibrations (see § 75.59, and RT 623);

(12) Reporting of Appendix E emission rate test data (see §§ 75.59, and RT 650–653);

(13) Reporting of span effective date information and flow rate span values (see § 75.53, and RT 530); and

(14) Removal of the recordkeeping provisions of §§ 75.50, 75.51, and 75.52 that are no longer effective.

Rationale

The majority of the proposed changes to subparts F and G are needed to support proposed substantive changes elsewhere in part 75. EPA is also proposing certain minor revisions to the order and wording of provisions in these subparts so that the records required by the rule match up consistently with the record type descriptions in the EDR. Certain utility groups previously had objected that EPA had not made the EDR format available for formal public notice and comment. The Agency maintains that it is not required to provide notice and comment for the EDR. The data included in (or proposed to be included in) the EDR are also listed in the rule (or the proposed rule revisions) as requirements under the recordkeeping and/or reporting provisions of §§ 75.53 through 75.64, which have already undergone (or are undergoing) public notice and comment. Since the EDR simply shows how to present electronically the data whose submission is (or will be) required by the rule, it is the rule, not the EDR, that imposes the data requirements. Notice and comment on the contents of the EDR would therefore be unnecessary and duplicative. Moreover, the requirement to present the rule's data requirements in a specified format is authorized by § 75.64(d), which requires a quarterly report to be submitted in the format specified by the Administrator. Like the data requirements, this format requirement in part 75 was adopted after public notice and comment.

In today's rulemaking, EPA has developed draft EDR revisions simultaneously with the proposed rule revisions and is therefore including the draft EDR revisions in the docket for comment at the same time as the proposed rule revisions (see Docket A–97–35, Item II–A–12). EPA is also posting the draft EDR v2.1 revisions and draft EDR v2.1 reporting instructions on the Acid Rain Homepage (www.epa.gov/acidrain). However, the Agency maintains that notice and comment are not necessary for revisions to the EDR so long as the data included in the EDR is the same as the data required by rule provisions that have undergone or are undergoing notice and comment. Thus, future EDR revisions may be made without prior notice and comment on the EDR in order to implement rule revisions for which notice and opportunity for comment are provided. However, the Agency will continue its informal procedures for involving the affected stakeholders in any such EDR revisions.

There are a number of other proposed changes to §§ 75.54–75.64 that have been included to implement existing provisions in other sections of part 75. First, information on test numbers and reasons for tests would be required so that quality-assurance test data can be more easily correlated and interpreted. Second, the reporting of various run-specific and point-specific RATA support information would be required (e.g., point velocity head readings, gas reference method quality-assurance data, moisture reference method data, etc.). The Agency believes that most testing companies currently either collect these data electronically or enter the data into computer programs manually to determine RATA results. By requiring the reporting of these data elements in a standard electronic format, the Agency believes that both facilities and regulatory personnel would be able to more easily interpret data that are currently provided by test contractors in many different hardcopy formats.

The Agency is proposing not to require the electronic reporting of RATA support information prior to the year 2000. Sections 75.56 (a)(5)(iii)(F) and (a)(7) and § 75.64(a)(1) of part 75 currently require RATA supporting information to be reported in the electronic quarterly report. EPA believes, however, that it would be more cost effective to require the more detailed RATA support records to be electronically reported beginning in the year 2000, rather than having a two-stage implementation. The Agency has notified all designated representatives that this RATA supporting information will not be required to be reported electronically, in RT612 and 613 of the quarterly report, prior to January 1, 2000.

The Agency notes that certain data elements (e.g., yaw angle, pitch angle, axial velocity, wall effect point identifier, etc.) have been included in anticipation of future revisions to EPA Reference Method 2. EPA is presently evaluating a number of alternative flow rate measurement methodologies, such as the use of a 3-dimensional probe. Depending on the outcome of the Agency's evaluation, one or more of these alternative flow measurement techniques may be allowed beginning in the year 2000. Therefore, EPA believes it is appropriate to include data elements to support these anticipated Method 2 revisions in draft EDR version 2.1.

Finally, by changing the requirements for reporting the results of the most recent RATA from requiring it to be reported in the quarter in which it was performed, to requiring it to be reported in the quarter in which it was performed and each subsequent quarter in which a BAF that was calculated using the results of that RATA are used, EPA would make the individual quarterly reports more self contained and make it easier for people who are using the reported data to understand how the BAFs reported in those reports were applied. EPA considered adding a field to the hourly emissions data record for each pollutant to indicate the BAF applied in that hour. However, the Agency received requests from utilities on an early draft of the EDR revisions that the hourly emissions data record types not be revised to add a field for BAF. The Agency believes that reporting the results of the most recent RATA, including the BAF, in each quarterly report would accommodate the utilities' requests not to add the BAF to each hourly record type and would achieve the objective of making the quarterly reports easier to interpret because the BAF being applied will be found in each quarterly report. In addition, since electronic RATA results involve a relatively small amount of information that can be copied into subsequent reports and does not have to be recreated, it should not be a significant burden to reporting facilities.

The proposed revisions would also remove the requirement to report the reasons for missing data and make it optional. However, even if the information is not reported, the reasons for missing data would have to be maintained on site in a manner suitable for inspection. Based on the high data availability achieved during initial implementation of the program, the Agency believes that this type of information is not needed in the review of most quarterly reports. For those situations in which the Agency may wish to review this information, the records would still be on-site for audit purposes or for submittal to the Agency.

The EPA is also proposing to incorporate additions which would allow the reporting of electronic signatures and certification statements so that no hardcopy reporting of any kind (e.g., cover letters) would be necessary to meet the quarterly report requirements.

Finally, the removal of recordkeeping §§ 75.50, 75.51, and 75.52 (and the corresponding explanatory text included in Appendix J to the existing rule) is necessary because those sections were scheduled for replacement during the May 17, 1995 rule revisions. At that time, §§ 75.54, 75.55, and 75.56 were added as replacements for §§ 75.50, 75.51, and 75.52, effective January 1, 1996. Because the effective date is now past, the old sections and Appendix J will be removed and reserved in order to prevent any confusion.

9. Electronic Transfer of Quarterly Reports

Background

Sections 75.64(a) and (d) of the original January 11, 1993 Acid Rain rule requires emissions, monitoring, and quality assurance data to be electronically reported to the Administrator on a quarterly basis in a format to be specified by the Administrator. Version 1.3 of the Electronic Data Reporting (EDR) format (see Docket A–97–35, Item II–I–5) further specifies the record structures to be used to report the required data elements. Page 3–3 of the May 1995 Acid Rain Program CEMS Submission Instructions (see Docket A–97–35, Item II–I–4) further specifies the mode of transmission of the electronic data file to the Agency. Three modes of transfer are listed as options: (a) by mail on diskette, (b) by mail on magnetic tape, or (c) through direct electronic transfer.

Since the beginning of the program, the Agency has received quarterly reports by mail on diskette and through direct electronic transfer. To date, the magnetic tape option has never been utilized. Based on the first four years of implementation of part 75, the Agency believes that the use of the direct electronic transfer mode of transmission has many advantages to the Agency and to the affected sources. In fact, more than seventy percent of the reports for sources currently affected by part 75 were submitted directly to the EPA mainframe with EPA-provided software in second quarter 1997, and the number of sources using this option has steadily increased over time (see Docket A–97–35, Item II–I–8).

Discussion of Proposed Changes

Today's proposal would require quarterly reports to be submitted via direct electronic transfer unless otherwise approved by the Administrator. This would remove the option of sending files through the mail on interceding media except for hardship cases where a modem is not available or where technical difficulties prevent the successful transmission of files via modem.

An additional revision to section 4 of Appendix A to part 75 would require data acquisition and handling systems (DAHS) to be capable of transmitting a record of measurements and other required information by direct computer-to-computer electronic transfer via modem and EPA-provided software.

Rationale

For each quarterly report submitted, the Agency performs an assessment which results in a feedback report for the submitting designated representative. This feedback report provides information to the facility that may be used in making trading decisions, that may indicate that a change is needed to the facility software, and/or that may indicate that the file needs to be corrected and resubmitted. A major advantage of submission through direct electronic transfer with a modem and EPA-provided software is that the designated representative submitting the file receives the EPA assessment of the submitted data much more quickly than for a file that is transmitted through the mail on diskette. Currently, for a file that is submitted to the Agency by electronic transfer via modem and EPA-provided software, the EPA assessment is received by the designated representative, via modem and EPA-provided software, immediately (typically within ten minutes) after the transmission of the quarterly report file. However, for files submitted on diskette that must travel through the mail system and be processed by Agency personnel, a letter containing the EPA assessment is currently sent to the designated representative through the mail and arrives 45 days or later from when the submission was originally received by the Agency. Therefore, with direct electronic transfer, potential errors get corrected and resolved more quickly and trading decisions can be made with assurance that submitted data meets the minimum quality standards acceptable to the Agency. Additionally, the source may electronically submit the quarterly report, via modem and EPA software, prior to the deadline, immediately receive the EPA assessment, fix any errors, and resubmit the file by the deadline. Many utilities have indicated that this is an important advantage over submission of the quarterly report by diskette.

Another benefit of direct electronic transfer is the reduced risk of error in transmission to the Agency or handling at the Agency. Throughout the implementation of the program, many files submitted on diskette through the mail have been lost, returned to the sender, damaged in transit, or contained viruses (see Docket A–97–35, Item II–I–8). When a file is submitted using direct electronic transfer of a quarterly report, the designated representative submitting the file(s) receives an immediate confirmation that the file was received by the Agency.

Further, immediate feedback from the agency on quarterly report submissions may also contribute to cost savings for facilities if a file submitted via direct electronic transfer is rejected and required to be amended and resubmitted. Utilities have indicated that submitting the report to EPA, receiving feedback, and making the necessary corrections to the file in a single work session significantly reduces the cost of reworks, particularly for facilities that retain their master file at the individual plant locations.

An additional advantage to direct electronic transfer is the reduced cost to the Agency resulting from the minimized EPA labor hours required to process a diskette. For instance, a diskette transmitted through the mail must be catalogued, scanned for readability and viruses, uploaded to the EPA mainframe Emissions Tracking System, and renamed. On the other hand, transmission of a file by direct computer-to-computer electronic transfer using EPA software eliminates all of those manual steps because they are performed automatically by the EPA software used for transmission of the report.

A possible concern about a requirement to submit the quarterly report via modem is the possibility that source may not be equipped with a modem and electronic transfer capability. Although the Agency believes that most sources currently have a modem or will have a modem by the year 2000, the Agency understands that a very small percentage might not. Therefore, the Agency would accept petitions from sources unable to transmit files via modem in order to allow transmission via diskette for hardship cases.

Additionally, a utility group representative raised a concern about the possibility of a computer at either the facility source or at the EPA being inoperative at the time of the deadline for transmission, preventing a source from successfully transferring the quarterly report to the Agency. In order to minimize the risk of this type of problem, there is a wide window, currently thirty days, during which EPA will accept quarterly report transmissions each quarter. Additionally, EPA has instituted preventative measures to minimize the possibility that the EPA computer would be inoperative for an extended length of time, preventing quarterly report transmission. Nevertheless, the Agency accepts that it is conceivable that a technical difficulty could prevent the successful electronic submission of a quarterly report and, therefore, would also approve diskette submission on an as-needed basis for sources unable to transfer a file via modem and EPA-provided software due to technical difficulties. Furthermore, EPA solicits comment on whether it should allow a grace period for late submissions due to a technical difficulty with the EPA computer.

Finally, section 4 of Appendix A to part 75 would be amended to require the DAHS to be capable of transmitting the required information by direct electronic transfer via modem and EPA-provided software, for consistency with the proposed § 75.64(f). In addition, section 4 of Appendix A to part 75 would retain the requirement for the DAHS to be capable of transmitting a record of measurements and other required information via an IBM-compatible personal computer diskette so that an on-site inspector could collect electronic data on a diskette for review.

S. Revised Traceability Protocol for Calibration Gases

Background

Currently, Appendix H to part 75 requires affected units to follow a 1987 version of EPA Protocol procedures for developing calibration gases. This protocol document has been superseded by a later version, the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA 600/R–97/121. The 1997 document is actually five protocols. Two of these protocols (formerly known as Protocols 1 and 2) have been combined to allow both CEMS and ambient air analyzers to be calibrated from gases produced either without dilution (Procedure G1) or with dilution (Procedure G2). The remaining three protocols (Procedures P1, P2, and P3) describe procedures that are mandatory for ambient air quality analyzers (not continuous emission monitoring systems).

The 1997 Protocol document, described above, is required by other parts of the CFR, such as the NSPS provisions in part 60. Because the old and new protocols specify different certification periods (i.e., useful shelf lives) for most calibration gases, some affected units that must comply with both part 60 and part 75 have been forced to replace calibration gas cylinders more frequently because of the shorter certification period in the 1987 Protocol procedures required by part 75.

Under the 1987 Protocol document, affected units with low SO_2 emission rates occasionally had difficulty finding calibration gases that were within the concentration ranges required by Appendix A to part 75. The 1997 Protocol document allows calibration gases to be developed over a wider range of concentrations than was previously allowed.

Under the current part 75 rule, ''Protocol 1 gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value).'' However, no method is specified to determine the uncertainty value. The overall uncertainty in the concentration estimated for a calibration gas comes from many different sources, including uncertainty in the reference standards, uncertainty in the analyzer multi-point calibration, uncertainty in the zero/span correction factors, and measurement imprecision.

Discussion of Proposed Changes and Rationale

Today's rule proposes to remove Appendix H and revise parts 72 and 75 to be consistent with the 1997 Protocol document. The following sections of part 75 would be revised: §§ 72.2 and 72.3; sections 5.1.1 through 5.1.6, 6.2, and 6.3.1 of Appendix A; and all of Appendix H.

The final rule would incorporate by reference the 1997 Protocol document. This is the preferred option for the following reasons: (a) calibration gas certification periods would be identical under parts 60 and 75, thereby allowing affected units to reduce expenditures on calibration gas without sacrificing accuracy or performance; (b) lower emitting affected units would more easily be able to comply with the required range of calibration gas concentrations; (c) improved assaying procedures and accuracy determinations would be allowed; and (d) a wider selection of calibration gases would be allowed.

While today's proposal would retain the requirement for EPA protocol gases to be within 2.0 percent of the tag value, section 5.1.3 in Appendix A would be revised to specify the use of the uncertainty calculation procedure in section 2.1.8 of the 1997 Protocol document for estimating the analytical uncertainty associated with the assay of the calibration gas. This uncertainty estimate includes the uncertainty of the reference standard and any gas manufacturer's intermediate standard (GMIS) and interference correction equation that may be used in developing the calibration gas.

EPA proposes to change the term ''Protocol 1 gas'' to ''EPA protocol gas'' because the 1997 Protocol document combines the Protocol 1 and Protocol 2 procedures; therefore, the term ''Protocol 1 gas'' would no longer be used.

Today's proposal would also continue to allow a ''research gas mixture'' to be used as a calibration gas. However, an RGM would need to meet the same 2.0 percent uncertainty requirement that a protocol gas would meet.

The proposed rule would explicitly allow GMISs to be used as calibration gas for two reasons. First, an EPA protocol gas may be made from a GMIS. Therefore, GMISs are at least as accurate as EPA protocol gases. Second, GMISs are more readily available and less expensive than standard reference material or National Institute of Standards and Technology (NIST) traceable reference material, both of which are allowable as calibration gas under part 75.

Today's proposal clarifies that NIST/EPA-approved certified reference materials (CRMs) would be acceptable as calibration gas by adding those CRMs to the definition of ''calibration gas'' in § 72.2.

The 1997 Protocol document accepts primary reference standards from the Netherlands Measurement Institute as being equivalent to standard reference materials from the NIST. As a result, today's proposal adds ''standard reference material-equivalent compressed gas primary reference material'' to the ''calibration gas'' definition in § 72.2 and to section 5.1.2 of Appendix A.

Finally, the definition of ''zero air material'' would be revised to accommodate other acceptable procedures.

Major differences between the 1987 Protocol procedures and the 1997 Protocol procedures are explained on pages 1–1 through 1–3 of the 1993 Protocol document and on pages 1–1 through 1–2 of the 1997 Protocol document (see Docket A–97–35, Items II–I–23 and 24).

T. Appendix I—New Optional Stack Flow Monitoring Methodology

Background

Section 412 of the Act requires that units subject to title IV install SO_2 concentration monitors and volumetric flow monitors for the purpose of determining SO_2 emissions. The purpose of the volumetric flow requirement is to enable a unit to convert SO_2 concentrations into mass emission rates of pounds per hour (lbs/hr). Volumetric flow is also used to determine heat input rate in mmBtu/hr and CO_2 mass emission rate in ton/hr.

In December 1991, 56 FR 63002 (December 3, 1991), EPA proposed an exception to the requirement to install SO_2 concentration monitors and volumetric flow monitors at oil- and gas-fired units in Appendix D to part 75. The exception relies on fuel flowmeters and fuel sampling and analysis to determine SO_2 emissions from oil- and gas-fired units. In comments on the December 1991 proposed rule, some industry commenters also advocated allowing oil- and gas-fired units to use a diluent monitor, an F-factor, and a fuel flowmeter as an alternative to a volumetric flow monitor. An F-factor is a fuel-specific constant that relates the heat content of a fuel and the volume of gases given off upon combustion. It is used to convert pollutant concentrations into units of pounds of pollutant per million British thermal units of heat input (lb/mmBtu). EPA already allows the use of F-factors in emissions monitoring under part 75 and under 40 CFR part 60, subparts Da and Db. Method 19 of Appendix A to part 60 uses F-factors as the reference methods for calculating SO_2 and NO_X emissions in terms of lb/mmBtu for subpart Da and Db units. F-factors also are used in the performance tests for certain pollutants required under § 60.8 to determine if a source is in compliance with a particular emission standard in lb/mmBtu. Part 75 also uses F-factors in conjunction with diluent gas and volumetric flow data to determine heat input under section 5 of Appendix F to part 75. Table 19–1 of Method 19 in Appendix A to part 60 and Table 1 in section 3.3.5 of Appendix F to part 75 list the appropriate F-factors for different types of fuel, including oil and natural gas.

Although the commenters supported the two exceptions included in Appendix D, some commenters did not believe the exceptions would be economical at all oil- and gas-fired units. According to one commenter, fuel sampling protocols have an inherently high bias because they assume a 100 percent conversion of fuel sulfur into SO_2, which results in higher emissions reporting from fuel sampling protocols than from CEMS. The commenter claimed that the high bias appears to be in the range of 5 to 10 percent. According to the commenter, the higher emissions reporting ''penalty'' that is inherent in fuel sampling protocols would justify installing SO_2 CEMS at some oil- and gas-fired units, particularly large, base-loaded oil-fired units. In addition, the commenter claimed that, for oil- and gas-fired units which install SO_2 CEMS, use of the ''F-factor/fuel flow method''—which includes use of an F-factor, a fuel flowmeter, fuel sampling data, and a diluent (CO_2 or O2) concentration monitor—would provide much more accurate and precise information than volumetric flow monitors (see Docket A–90–51, Item IV–D–184).

In a four-day experiment performed in 1991 by one commenter, measurements from the F-factor/fuel flow method were compared to those generated by a combined SO_2 CEMS and a volumetric flow monitor. However, EPA did not believe that four consecutive days of data were sufficient to support a conclusive equivalency determination. Instead, in the January 11, 1993 final rule (58 FR 3590, 3643), EPA reserved Appendix I to part 75 for the F-factor/fuel flow method and stated that, to be approved, the method would have to meet the criteria for alternative methods as required by section 412 of the Act and the provisions of § 75.40 in a 30-day (720 hour) trial.

Section 412 of the Act requires that an alternative monitoring system provide information with ''the same precision, reliability, accessibility, and timeliness as that provided by CEMS . . .'' 42 U.S.C. 7651k. To be approved, the alternative monitoring system must meet the criteria for alternative methods in a 720 hour trial as required by the provisions of subpart E of part 75. The rule designates a certified CEMS or a reference method according to Appendix A to part 60 as the reference for evaluating the alternative monitoring system's performance.

In order to meet the precision and reliability criteria, an alternative monitoring system must achieve performance specifications and quality assurance requirements equivalent to those for CEMS. In addition, to demonstrate precision, an alternative monitoring system must pass three statistical tests evaluating the flow CEMS and alternative method in terms of their respective systematic error, random error, and correlation. Additionally, to meet the reliability criterion, the alternative monitoring system is required to match a certified CEMS in terms of annual availability. Finally, to meet the accessibility and timeliness criteria, an alternative monitoring system must match the CEMS' ability to record requisite emissions data on an hourly basis and report results within 24 hours.

In 1995, Long Island Lighting Company (LILCO) sponsored an ''alternative flow monitor demonstration project'' to demonstrate the equivalency of fuel flow measurements and F-factor calculations to stack instrument flue gas measurements for the determination of volumetric flow. The project was performed by Entropy at LILCO's Port Jefferson Unit 4, a 180 MW oil-fired unit that burns residual oil with a maximum sulfur content of one percent. The components of the alternative method consisted of a fuel flowmeter and a CO_2 CEMS. The alternative F-factor/fuel flow method was compared to a flue gas volumetric flow CEMS.

Testing of the F-factor/fuel flow method took place in April–May 1995, and 739 hours of data were collected over a wide range of operating loads (40 MW—190 MW). Fuel oil samples were taken daily and analyzed for density and carbon content. The alternative method successfully passed statistical tests but showed statistically significant bias (see Docket A–97–35, Item II–D–14). Due to the bias uncovered during the test, EPA concluded that the alternative flow monitor demonstration project did not meet the requirements of subpart E of part 75 for an alternative monitoring system. However, EPA is proposing that a default multiplier, derived from the demonstration data, be incorporated into the equations used under Appendix I to compensate for the detected systematic bias and thereby help to ensure that emissions are not underestimated when using the F-factor/fuel flow method. With these provisions, EPA proposes to include the F-factor/fuel flow method as an excepted method for determining flow in Appendix I to part 75. The proposed default multiplier, 1.12, is based on the data and results of the LILCO demonstration and is supported by EPA and the Class of '85 Regulatory Response Group. The default multiplier would be incorporated into the equations used under Appendix I whenever a relative accuracy test audit is performed on a component-by-component basis as was proposed in the LILCO demonstration.

Discussion of Proposed Changes

EPA proposes to include the F-factor/fuel flow method in Appendix I as an excepted method for use in place of a volumetric flow monitor for oil- and gas-fired units that burn only natural gas and/or fuel oil. The F-factor/fuel flow method uses fuel flow measurement, fuel sampling data, CO_2 (or O_2) CEMS data and F-factors to determine the flow rate of the stack gas. EPA proposes limiting use of the F-factor/fuel flow method to oil- and gas-fired units that burn only natural gas and/or fuel oil because of the greater fuel consistency of oil and natural gas and because the fuel flow rates of oil and natural gas can be monitored accurately with a fuel flowmeter, unlike the feed rate of coal.

Appendix I flow monitoring would be done using any of the following combinations of components: a CO_2 monitor and a volumetric oil flowmeter, a CO_2 monitor and a mass oil flowmeter, a CO_2 monitor and a volumetric gas flowmeter, an O_2 monitor and a volumetric oil flowmeter, an O_2 monitor and a mass oil flowmeter, or an O_2 monitor and a volumetric gas flowmeter.

Today's proposal would amend § 75.20, "Certification and Recertification Procedures," to add certification and recertification procedures for units using Appendix I flow monitoring systems. Initial certification of the components of the F-factor/fuel flow method would be performed either component by component or on a system basis. If each component is tested separately, then the fuel flowmeter would be tested in accordance with section 2.1.5 of Appendix D, and the CO_2 or O_2 monitor would have to pass a 7-day calibration test, a linearity check, a cycle time test and a relative accuracy test audit (RATA) using Method 3A from Appendix A to part 60. A bias test would also have to be conducted. If the excepted Appendix I flow monitoring system is tested as an entire system, then the following tests would be performed: a 7-day calibration error test, a linearity check, and a cycle time test on the CO_2 or O_2 monitor, and a relative accuracy test audit on the entire excepted flow monitoring system using Method 2 from Appendix A to part 60, and a bias test. The owner or operator would also test the data acquisition and handling system. Upon successful completion of all certification tests, the Appendix I system would be considered provisionally certified.

Today's proposal would amend § 75.21, "Quality Assurance and Quality Control Requirements," to include Appendix I flow monitoring systems. A unit utilizing the optional F-factor/fuel flow method would have to meet ongoing quality assurance testing requirements. First, the daily and quarterly assessment requirements for a CO_2 or O_2 monitor in sections 2.1 and 2.2 of Appendix B would have to be followed. Second, one of the following would have to be met, depending on whether the owner or operator chooses to test the method on a component-by-component basis or on a system level: (1) the fuel flow meter quality assurance requirements and a separate RATA on the CO_2 (or O_2) monitor; or (2) a system level flow RATA. If the components are tested separately, the applicable procedures in section 2.1.6 of Appendix D would have to be followed for the fuel flowmeter quality assurance (i.e., a flow meter accuracy test, a transmitter accuracy test and primary element inspection, and/or the supplemental quarterly fuel flow-to-load quality assurance testing) and the applicable RATA procedures in sections 6.5 through 6.5.2.2 of Appendix A for the CO_2 (or O_2) monitor would be followed. In addition, the bias test would have to be performed on the CO_2 (or O_2) monitor and, if the bias test is failed, a bias adjustment factor (BAF) would have to be calculated and applied to hourly data.

If the entire system is tested, the applicable procedures in sections 6.5 through 6.5.2.2 of Appendix A would have to be used to meet the performance specifications for flow relative accuracy in section 3.3.4 of Appendix A. The bias test would have to be performed on the volumetric flow data and, if the bias test is failed, a BAF would have to be calculated using the procedures in section 7.6 of Appendix A.

Several other sections of the rule would be modified or added in order to incorporate the new excepted method described in Appendix I, including §§ 75.30, 75.57, 75.58, and 75.59. Section 75.30, "General Provisions" (for missing data substitution procedures), would be modified by adding quality assured data from a certified excepted flow monitoring system under Appendix I to the list of monitoring systems that measure flow rate data, for which the missing data substitution procedures of subpart D are required. If fuel sampling data, fuel flow rate data, and diluent gas data are missing, then the data acquisition and handling system would have to substitute for missing volumetric flow data. In addition, § 75.57, would include additional information that Appendix I flow monitoring systems must record. This includes fuel flow rate data and data from component monitors. Section 75.58(g) would be added to address specific volumetric flow rate record provisions for units using the optional protocol in Appendix I. Section 75.59, "Certification, Quality Assurance and Quality Control Record Provisions," would also include certification and quality assurance information that facilities must record for Appendix I flow monitoring system tests.

Finally, the new proposed Appendix I would describe the applicability, procedures, calculations, missing data, and recordkeeping and reporting requirements for units using Appendix I to determine flow.

The Appendix I formulas are more complex if an O_2 monitor is used. EPA proposes to allow the use of an O_2 monitor for Appendix I; however, the initial programming of the formulas and monitoring plan development may take longer for Appendix I flow monitoring systems that use an O_2 monitor.

Volumetric stack flow rate during oil combustion would be calculated from (1) a bias adjustment factor from the applicable bias test results; (2) the fuel flow rate (in gal/hr); (3) the fuel density (in lb/gal); (4) the percent carbon by weight; (5) the CO_2 (or O_2) concentration percent by volume; and (6) the appropriate conversion factor. The carbon content of the fuel would have to be determined according to the procedures in section 2.1 of Appendix G and the density of the oil would have to be determined according to the procedures in section 2.2 of Appendix D.

Rationale: EPA is proposing 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 because 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, while affording cost savings that some industry representatives estimate could be substantial. The Agency solicits comment on the proposed Appendix I and associated changes to part 75.

Appendix I may offer cost savings to some oil and gas fired units. Representatives from oil- and gas-fired units have estimated that the costs of operating, maintaining and testing volumetric flow monitors range from approximately $15,000 to $25,000 per year. In contrast, using the F-factor/fuel flow method is estimated to result in costs of only approximately $5,000 to $7,000 per year due to elimination of the operating, maintenance, testing and fuel costs associated with the volumetric flow monitor.

U. The Use of Predictive Emissions Modeling Systems (PEMS)

A number of parties have submitted preliminary field test data designed to demonstrate that EPA should set forth specific requirements for alternative monitoring methodologies that predict NO_X emission rates at gas-fired units. These ''predictive emissions modeling systems'' (PEMS) use mathematical models to predict NO_X emission rates based on sensor readings of key operating parameters. The agency is evaluating the submitted data and will consider taking further action under a future rulemaking if additional study demonstrates the equivalency of PEMS to CEMS for well defined classes of units.

IV. Administrative Requirements

A. Public Hearing

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

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

B. Public Docket

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

C. Executive Order 12866

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

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

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

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

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

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

D. Unfunded Mandates Reform Act

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

This proposed rule is not expected to result in expenditures of more than $100 million in any one year and, as such, is not subject to section 202 of the UMRA. Although the proposed rule is not expected to significantly or uniquely affect small governments, the Agency has notified all potentially affected small governments that own or operate units potentially affected by the proposal in order to assure that they have the opportunity to have meaningful and timely input on the proposed 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.

E. Paperwork Reduction Act

The information collection requirements in this proposal 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. 1835.01), 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.gov/icr.

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

The average annual projected hour burden is 2,608,836, which is based on an estimated 835 likely respondents (on a per utility basis). The projected cost burden resulting from the collection of information is $47,555,000, which includes a total projected capital and start-up cost of $1,436,000 (for monitoring equipment/software), and a total projected operation and maintenance cost (which includes purchase of testing contractor services and total projected fuel sampling and analysis cost of $716,000) of $46,119,000. 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.

Comments are requested on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques. Send comments on the ICR to the Director, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M Street, SW, Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Include the ICR number in any correspondence. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after May 21, 1998, a comment to OMB is best assured of having its full effect if OMB receives it by June 22, 1998. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

F. Regulatory Flexibility Act

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 proposed rule would not have a significant impact on a substantial number of small entities.

Today's proposed revisions to part 75 result in a net cost reduction to utilities affected by the Acid Rain Program, including small entities. Most importantly, the proposed changes to Appendix D and the addition of an optional calculation procedure instead of actual monitoring for oil- and gas-fired units with low mass emissions would 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. Therefore, I certify this action will not have a significant economic impact on a substantial number of small entities.

G. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''ANTTAA''), Pub L. No. 104–113 15 USC 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.

This regulatory action proposes to incorporate by reference voluntary consensus standards pursuant to § 12(d) of the NTTAA. The EPA has adopted the general policy of using voluntary consensus standards from technically knowledgeable groups such as the Organization for International Standards (ISO), the American Society for Testing and Materials (ASTM), the American Society of Mechanical Engineers (ASME), the American Gas Association (AGA), the Gas Processors Association (GPA), and the American Petroleum Institute (API).

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

EPA proposes to incorporate by reference the following voluntary consensus standards for use under part 75:

a. ASTM D5373–93 ''Standard Methods for Instrumental Determination of Carbon, Hydrogen and Nitrogen in laboratory samples of Coal and Coke.'' This standard is proposed to be incorporated by reference for use under section 2.1 of Appendix G to part 75 and is discussed further in section III.Q.1 of this preamble.

b. API Section 2 ''Conventional Pipe Provers'' from Chapter 4 of the *Manual of Petroleum Measurement Standards,* October 1988 edition. This standard is proposed to be incorporated by reference for use under paragraph (g)(1)(i) of § 75.20 and under section 2.1.5.1 of Appendix D to part 75. The proposal to incorporate this standard by reference is discussed further in section III.P.6.(b) of this preamble.

List of Subjects in 40 CFR Parts 72 and 75

Air pollution control, Carbon dioxide, Continuous emission monitors, Electric utilities, Environmental protection, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: April 27, 1998.

Carol M. Browner,

Administrator, U.S. Environmental Protection Agency.

For the reasons set out in the preamble, title 40 chapter 1 of the Code of Federal Regulations is proposed to be 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 revising the definitions of ''calibration gas,'' ''excepted monitoring system,'' ''gas-fired,'' ''pipeline natural gas,'' ''span,'' ''stationary gas turbine,'' and ''zero air material''; by revising paragraph (2) of ''oil-fired'' and paragraph (2) of the ''peaking unit''; by adding paragraph (3) to the definition of ''peaking unit''; by adding new definitions for ''conditionally valid data,'' ''EPA protocol gas,'' ''gas manufacturer's intermediate standard,'' ''low mass emissions unit,'' ''maximum rated hourly heat input,'' ''ozone season,'' ''probationary calibration error test,'' ''research gas mixture (RGM)'', and ''standard reference material-equivalent compressed gas primary reference material''; and by removing the definition of ''protocol 1 gas,'' 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.

* * * * *

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 of 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.

* * * * *

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.

* * * * *

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

* * * * *

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 with a total sulfur content no greater than the total sulfur content of natural gas (including coal-derived gaseous fuel) for at least 90.0 percent of the unit's average annual heat input during the previous 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,

(A) The designated representative submits 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) For a unit that 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, if the designated representative submits: 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 with a total sulfur content no greater than the total sulfur content of natural gas 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 with a total sulfur content no greater than the total sulfur content of natural gas 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 (2)(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 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 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 a unit failing to meet the criteria in paragraph (2) of this definition initially qualified as a gas-fired unit under paragraph (3)(ii) of this definition, the unit may qualify as a gas-fired unit for a subsequent year only under paragraph (3)(i) 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.

* * * * *

Low mass emissions unit means a gas-fired or oil-fired unit that burns only natural gas and/or fuel oil and that qualifies under §§ 75.19(a) and (b) of this chapter.

* * * * *

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

Oil-fired means:

* * * * *

(2) For purposes of part 75 of this chapter, a unit may qualify as oil-fired if the unit burns only fuel oil and gaseous fuels with a total sulfur content no greater than the total sulfur content of natural gas and if the unit does not meet the definition of gas-fired.

* * * * *

Ozone season means the period of time from May 1st to September 30th, inclusive.

* * * * *

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,

(A) The designated representative submits 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) For a unit that 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, the designated representative submits: all available capacity factor data, beginning with the date on which the unit commenced commercial operation; and projected capacity factor.

(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 gas-fired unit under paragraph (2)(ii) of this definition, the unit may qualify as a peaking unit for a subsequent year only under paragraph (2)(i) of this definition.

* * * * *

Pipeline natural gas means natural gas 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. The hydrogen sulfide content of the natural gas must be documented 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.

* * * * *

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

* * * * *

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.

* * * * *

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.

* * * * *

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, a concentration of CO_2 above 400 ppm; or

(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; or

(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 specific CEM readings or cause the CEM being zeroed to read concentrations of the gas being zeroed.

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

§ 72.3 Measurements, abbreviations, and acronyms.

* * * * *

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.

* * * * *

§ 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 conditional data were reported in the quarterly report. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional 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 continues to read as follows:

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

7. Section 75.1 is amended by revising paragraph (a) to read as follows:

§ 75.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to Sections 412 and 821 of the Clean Air Act, 42 U.S.C. 7401-7671q as amended by Public Law 101–549 (November 15, 1990) (the Act). In addition, this part sets forth provisions for the monitoring, recordkeeping, and reporting of NO_X mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NO_X mass emission reduction program, if these provisions are adopted as requirements under such a program.

* * * * *

8. Section 75.2 is amended by revising paragraph (a) and adding a new paragraph (c) to read as follows:

§ 75.2 Applicability.

(a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_X.

* * * * *

(c) The provisions of this part may apply to sources subject to a State or federal NO_X mass emission reduction program, if these provisions are adopted as requirements under such a program.

9. Section 75.4 is amended by revising paragraphs (a) introductory text and (d)(1) and adding a new paragraph (i) to read as follows:

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the Acid Rain permit which governs that unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the Acid Rain permit. For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the provisions of this part become applicable upon the submission of an Opt-in permit application in accordance with § 74.14 of this chapter. The provisions of this part for the monitoring, recording, and reporting of NO_X mass emissions become applicable on the deadlines specified in the applicable State or federal NO_X mass emission reduction program, if these provisions are adopted as requirements under such a program. 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, 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 (h) of this section):

* * * * *

(d) * * *

(1) The maximum potential concentration of SO_2, the maximum potential NO_X emission rate, the maximum potential flow rate, as defined in section 2.1 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.

* * * * *

(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, or heat input, 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) January 1, 2000, for a unit that is existing and has commenced commercial operation by October 3, 1999; or

(2) For a new affected unit which has not commenced commercial operation by October 4, 1999, not 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 January 1, 2000, not later than the earlier of 45 unit operating days or 180 calendar days after the date that the unit recommences commercial operation.

10. Section 75.5 is amended by revising paragraph (f)(2) to read as follows:

§ 75.5 Prohibitions.

* * * * *

(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 emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

* * * * *

11. Section 75.6 is amended by redesignating paragraph (a)(40) as paragraph (a)(41) and by adding new paragraphs (a)(40) and (f) to read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(a) * * *

(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.

* * * * *

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005–4070: American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993), for § 75.20 and appendix D to this part.

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 emission, 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 a full scale exceedance, 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)(2), (e)(3) introductory text, (e)(3)(ii), (e)(3)(iv), and (e)(4) and by adding paragraph (d)(3), 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 natural gas or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 20 grains per 100 standard cubic feet (gr/100 scf)) 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 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 psychrometric chart (for saturated gas streams following wet scrubbers, 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 natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas);

(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. Appendix D shall not, however, be used when the unit combusts gaseous fuel with a total sulfur content greater than the total sulfur content of natural gas (i.e., > 20 gr/100 scf); when such fuel is burned, the owner or operator shall comply with the provisions of paragraph (e)(4) of this section; or

(3) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b).

(e) * * *

(2) When gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 20 gr/100 scf) is combusted in the unit, 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 with appendix D to this part, by following the fuel sampling and analysis procedures in section 2.3.1 of appendix D to this part, by meeting the recordkeeping requirements of § 75.55 or § 75.58, as applicable, and by 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 of this part. The flow monitor and diluent monitor shall meet all of the applicable quality control and quality assurance requirements of appendix B of this part.

(3) When gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 20 gr/100 scf) is burned in the unit, 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, on and after January 1, 2000, the SO_2 monitoring system shall be subject to the following provisions; prior to January 1, 2000, the owner or operator may comply with these provisions:

* * * * *

(ii) The calibration response of the SO_2 monitoring system shall 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). This calibration adjustment is optional if gaseous fuel is burned in the affected unit only during unit startup.

* * * * *

(iv) In accordance with the requirements of section 2.1.1.2 of appendix A to this part, for units that sometimes burn natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) 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 natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) is combusted. For units that burn only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) 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.

(4) During any hours in which a unit combusts only gaseous fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 20 gr/100 scf), 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.

* * * * *

14. Section 75.12 is amended by revising the title; by redesignating existing paragraphs (b), (c), and (d) as paragraphs (c), (d), and (f), respectively; by adding new paragraphs (b) and (e); 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).

* * * * *

(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, i.e., if the NO_X pollutant concentration monitor measures on a different moisture basis from the diluent monitor, the owner or operator shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in § 75.11(b).

(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.

* * * * *

(e) *Low mass emissions units.* Notwithstanding the requirements of §§ 75.12(a) and (c), the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system;

(2) Meet the requirements specified in paragraph (d)(2) of this section for using the excepted monitoring procedures in appendix E to this part, if applicable; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_X emission rate and hourly NO_X mass emissions.

* * * * *

15. Section 75.13 is amended by revising paragraphs (a) and (c) and by adding paragraph (d) 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 ''SO_2 continuous emission monitoring system'' is replaced with ''CO_2 continuous emission monitoring system,'' the phrase ''SO_2 concentration'' is replaced with ''CO_2 concentration,'' the term ''maximum potential concentration of SO_2'' is replaced with ''maximum potential concentration of CO_2,'' and the phrase ''SO_2 mass emissions'' is replaced with ''CO_2 mass emissions.''

* * * * *

(c) *Determination of CO_2 mass emissions using an O_2 monitor* according to appendix F. 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 defined in § 75.11(b), 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 ''SO_2 continuous emission monitoring system'' is replaced with ''CO_2 continuous emission monitoring system,'' the term ''maximum potential concentration of SO_2'' is replaced with ''maximum potential concentration of CO_2,'' and the phrase ''SO_2 mass emissions'' is replaced with ''CO_2 mass emissions.''

(d) *Determination of CO_2 mass emissions from low mass emissions units.* The owner or operator of a unit that qualifies as a low mass emissions unit under §§ 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a CO_2 continuous emission monitoring system and flow monitoring system;

(2) Meet the requirements specified in paragraph (b) or (c) of this section for use of the methods in appendix G or F to this part, respectively; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO_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. Revising the last sentence and 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; 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 terms ''SO_2 mass emissions'' and ''emissions'' are replaced with the term ''heat input'' and the phrase ''SO_2 continuous emission monitoring system and flow monitoring system'' is replaced with the phrase ''a diluent monitor and a flow monitor.'' The applicable equation in appendix F to this part shall be used to calculate the heat input from the hourly flow rate, diluent monitor 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) * * * The heat input may be apportioned either by using the ratio of load (in MWe-hr) for each individual unit to the total load for all units utilizing the common stack or by using the ratio of steam flow (in 1000 lb) for each individual unit to the total steam flow for all units utilizing the common stack. The heat input should be apportioned according to the procedures in 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 and 75.72.

17. Section 75.17 is amended by adding introductory text before paragraph (a) and 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.

Notwithstanding the provisions of paragraphs (a), (b), and (c) of this section, the owner or operator of an 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 provisions for monitoring NO_X emission rate in §§ 75.71 and 75.72.

(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 added to subpart B to read as follows:

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

(a) *Applicability.* (1) Consistent with the requirements of paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input, hourly NO_X emission rate, and hourly NO_X, SO_2, and CO_2 mass emissions from a low mass emissions unit. A low mass emissions unit is a gas-fired or oil-fired unit that burns only natural gas and/or fuel oil and that:

(i) Emits no more than 25 tons of SO_2 annually and no more than 25 tons of NO_X annually; and

(ii) Has calculated emissions of no more than 25 tons of SO_2 annually and no more than 25 tons of NO_X annually based on the maximum rated hourly heat input, the actual operating time for each fuel burned, and the low mass emissions excepted methodology, calculations, and values in paragraph (c) of this section.

(2) A unit may initially qualify as a low mass emissions unit only under the following circumstances:

(i) The designated representative provides historical actual and calculated emissions data from the previous three calendar years immediately prior to the submission of an application to use the low mass emissions excepted methodology, and the data demonstrates to the satisfaction of the Administrator that the unit meets the criteria in paragraphs (a)(1)(i) and (ii) of this section; or

(ii) If a unit does not have the historical data required in paragraph (a)(2)(i) of this section for any one or more of the previous three calendar years, the designated representative submits:

(A) Any historical annual emissions and operating data, as required in paragraphs (a)(1)(i) and (a)(1)(ii) of this section, beginning with the unit's first calendar year of commercial operation, and the data demonstrates to the satisfaction of the Administrator that the unit meets the criteria in paragraphs (a)(1)(i) and (a)(1)(ii) of this section; and

(B) A demonstration satisfactory to the Administrator that the unit will continue to qualify as a low mass emissions unit under the requirements of this paragraph (a). The demonstration shall include any historical emissions and operating data for less than a calendar year for the unit and projected emissions information for the unit, as determined using projected operating hours and fuel usage, and the low mass emissions excepted methodology, calculations, and values in paragraph (c) of this section.

(b) *Disqualification.* If a unit that initially qualifies as a low mass emissions units under this section changes the fuel that is burned in the unit such that a fuel other than natural gas or fuel oil is combusted in the unit, the unit is disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. In addition, if a unit that initially qualifies as a low mass emissions unit under this section emits more than 25 tons of SO_2 or 25 tons of NO_X in any calendar year or has calculated emissions greater than 25 tons of SO_2 or 25 tons of NO_X in any calendar year, as determined using the low mass emission equations in paragraph (c) of this section, the owner or operator of the unit shall have two quarters from the end of the quarter in which the exceedance occurs to install, certify, and report SO_2, NO_X, and CO_2 from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13, respectively. The unit shall be disqualified as a low mass emissions unit as of the end of the second quarter following the quarter in which either of the 25 ton limits was exceeded. A unit that has been disqualified from using the low mass emissions excepted methodology may subsequently qualify again as a low mass emissions unit under paragraph (a)(2) of this section, provided that if such unit qualified under paragraph (a)(2)(ii) of this section, the unit may subsequently qualify again if the unit meets the requirements of paragraph (a)(2)(i) of this section.

(c) *Low mass emissions excepted methodology, calculations, and values.*—(1) *Operating time.* (i) Report an hourly record if the unit operated for any portion of the hour or if records are missing, as to whether or not the unit operated for any portion of that hour.

(ii) Quarterly operating time (hr) is equal to the sum of all of the reported operating hours in the quarter, such that any hour in which the unit combusted fuel for any portion of the hour is considered a full hour.

(iii) Year-to-date cumulative operating time (hr) is equal to the sum of all of the reported operating hours in the year to date, such that any hour in which the unit combusted fuel for any portion of the hour is considered a full hour.

(2) *Heat input.* (i) Hourly heat input (mmBtu) is equal to the maximum rated hourly heat input, as defined in § 72.2 of this chapter. However, the owner or operator of an affected unit may petition the Administrator under § 75.66 for a lower value for maximum rated hourly heat input than that defined in § 72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(ii) Calculate the quarterly total heat input (mmBtu) using Equation 7a as follows:

$$HI_{qtr} = T_{qtr} \times HI_{hr} \quad \text{(Eq. 7a)}$$

where:

T_{qtr} = Actual number of operating hours in the quarter, in hr.

HI_{hr} = Hourly heat input under paragraph (c)(2)(i) of this section, in mmBtu.

(iii) Calculate the year-to-date cumulative heat input (mmBtu) as the sum of all of the hourly heat input values in the year to date.

(3) SO_2. (i) Calculate the hourly total SO_2 mass emissions (lbs) using Equation 7b and the appropriate fuel-based SO_2 emission factor from Table 1a for the fuel being burned in that hour. If more than one fuel is burned in the hour, use the highest emission factor for all of the fuels burned in the hour. If records are missing as to which fuel was burned in the hour, use the highest emission factor for all of the fuels capable of being burned in that unit.

TABLE 1a.—SO_2 EMISSION FACTORS (LB/MMBTU) FOR VARIOUS FUEL TYPES

Fuel type	SO_2 Emission factors
Pipeline Natural Gas	0.0006 lb/mmBtu.

TABLE 1a.—SO_2 EMISSION FACTORS (LB/MMBTU) FOR VARIOUS FUEL TYPES—Continued

Fuel type	SO_2 Emission factors
Natural Gas	0.06 lb/mmBtu.
Residual Oil	2.1 lb/mmBtu.
Diesel Fuel	0.5 lb/mmBtu.

$W_{SO2} = EF_{SO2} \times HI_{hr}$

(Eq. 7b)

Where:

W_{SO2} = SO_2 mass emissions, in lbs.

EF_{SO2} = Fuel-based SO_2 emission factor from Table 1a of this section, in lb/mmBtu.

HI_{hr} = Hourly heat input under paragraph (c)(2)(i) of this section, in mmBtu.

(ii) Calculate the quarterly total SO_2 mass emissions (tons) by summing all of the hourly SO_2 mass emissions under paragraph (c)(3)(i) of this section in the quarter and dividing by 2000 lb/ton.

(iii) Calculate the year-to-date cumulative SO_2 mass emissions (tons) by summing all of the SO_2 mass emissions under paragraph (c)(3)(i) of this section in the year to date.

(4) NO_X. (i) Determine the hourly NO_X emission rate (lb/mmBtu) by using the appropriate fuel and boiler type default NO_X emission rate in Table 1b for the fuel being burned in that hour. If more than one fuel is burned in the hour, use the highest emission rate for all of the fuels burned in the hour. If records are missing as to which fuel was burned in the hour, use the highest emission factor for all of the fuels capable of being burned in that unit.

TABLE 1b.—NO_X EMISSION RATES (LB/MMBTU) FOR VARIOUS BOILER/FUEL TYPES

Boiler type	Fuel type	NO_X Emission rate
Tangentially fired	Oil	0.366
Tangentially fired	Gas	0.290
Dry Bottom Wall fired	Oil	0.490
Dry Bottom Wall fired	Gas	0.400
Combustion Turbine	Oil	0.258
Combustion Turbine	Gas	0.172
Combined Cycle	Oil	0.273
Combined Cycle	Gas	0.273

(ii) Calculate the hourly total NO_X mass emissions (lbs) as the product of the NO_X emission rate (lb/mmBtu) and hourly heat input (mmBtu), using Equation 7c as follows:

$W_{NOX} = EF_{NOX} \times HI_{hr}$

(Eq. 7c)

where:

W_{NOX} = NO_X mass emissions, in lbs.

EF_{NOX} = Boiler-type and fuel-type NO_X emission factor from Table 1b of this section, in lb/mmBtu.

HI_{hr} = Hourly heat input under paragraph (c)(2)(i) of this section, in mmBtu.

(iii) Calculate the quarterly average NO_X emission rate (lb/mmBtu) by summing all of the hourly NO_X emission rates for the quarter and dividing the total by the number of reported operating hours under paragraph (c)(1)(i) of this section in the quarter.

(iv) Calculate the quarterly total NO_X mass emissions (tons) by summing all of the hourly NO_X mass emissions under paragraph (c)(4)(ii) of this section in the quarter and dividing the total by 2000 lb/ton.

(v) Calculate the year-to-date cumulative average NO_X emission rate (lb/mmBtu) by summing all of the hourly NO_X emission rates for all of the hours in the year to date and dividing the total by the number of reported operating hours under paragraph (c)(1)(i) of this section in the year to date.

(vi) Calculate the year-to-date cumulative NO_X mass emissions total (tons) by summing all of the hourly NO_X mass emissions under paragraph (c)(4)(ii) of this section in the year to date.

(5) *CO_2*. (i) Calculate the hourly total CO_2 mass emissions (tons) using Equation 7d and the appropriate fuel-based CO_2 emission factor from Table 1c for the fuel being burned in that hour. If more than one fuel is burned in the hour, use the highest emission factor for all of the fuels burned in the hour. If records are missing as to which fuel was burned in the hour, use the highest emission factor for all of the fuels capable of being burned in that unit.

TABLE 1c.—CO_2 EMISSION FACTORS (TON/MMBTU) FOR GAS AND OIL

Fuel type	CO_2 emission factors
Natural Gas	0.059 ton/mmBtu.
Oil	0.081 ton/mmBtu.

$W_{CO2}=EF_{CO2} \times HI_{hr}$

(Eq. 7d)

Where:

W_{CO2} = CO_2 mass emissions, in tons.

EF_{CO2} = Fuel-based CO_2 emission factor from Table 1c, in ton/mmBtu.

HI_{hr} = Hourly heat input under paragraph (c)(2)(i) of this section, in mmBtu.

(ii) Calculate the quarterly total CO_2 mass emissions (tons) by summing all of the hourly CO_2 mass emissions under paragraph (c)(5)(i) of this section in the quarter.

(iii) Calculate the year-to-date cumulative CO_2 mass emissions (tons) by summing all of the hourly CO_2 mass emissions under paragraph (c)(5)(i) of this section in the year to date.

(d) The quality control and quality assurance requirements in § 75.21 are not required for a low mass emissions unit for which the optional low mass emissions excepted methodology in paragraph (c) of this section is being used in lieu of a continuous emission monitoring system or an excepted monitoring system under appendix D or E to this part.

Subpart C—[Amended]

19. Section 75.20 is amended by:

a. Revising the title of the section;

b. Revising the titles of paragraphs (a)(3), (a)(4), (c), (d), (g), (g)(1), (g)(2), (g)(4), and (g)(5);

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

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

e. Revising and 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; and revising newly designated paragraphs (c)(4) introductory text, (c)(8) introductory text, (c)(8)(i), (c)(9)(ii), and (c)(10) introductory text; and

f. Adding new paragraphs (c)(5), (c)(6), (c)(7), (g)(6), (g)(7), (h), and (i), 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 §§ 75.13 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, each 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, provided that 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, 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 if the data validation procedures of paragraph (b)(3) of this section are applied to the initial certification (or recertification) of a continuous emissions monitoring system, it is possible for data recorded by the CEMS during the certification (or recertification) test period to be quality assured retrospectively, upon completion of all of the certification (or recertification) tests. Therefore, in certain instances, 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 written 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 written 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 written 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 beginning with the following time: 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 tests until the date and time that the owner or operator completes subsequently approved initial certification tests, if the data validation procedures of paragraph (b)(3) of this section were not used. 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.

* * * * *

(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; the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part to report volumetric flow; or 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

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(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 is determined by the Administrator to 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, 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 is determined by the Administrator to 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; changing of flow rate monitor polynomial coefficients; 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 stack flow rate or gas monitoring system for which the Administrator determines that a RATA is not necessary shall not be considered a recertification event. In such cases, any other tests that the Administrator determines to be necessary (linearity checks, calibration error tests, DAHS verifications, etc.) shall be performed as diagnostic tests, rather than recertification tests. The data validation procedures in paragraph (b)(3) of this section shall be applied 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 recertification testing after changing the flow rate monitor polynomial coefficients, the owner or operator shall complete a 3-level RATA. For all other 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.

(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 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.* (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.

(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, reprogramming, and any preliminary tests (e.g., trial RATA runs or a challenge of the monitor with calibration gases other than those used to perform the daily calibration error test) 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 after the probationary calibration error test that initiates the test period:

(A) For a linearity test and/or cycle time test, 168 consecutive unit operating hours;

(B) For a RATA (whether normal-load or multiple-load), 720 consecutive unit operating hours; and

(C) For a 7-day calibration error test, 21 consecutive unit operating days.

(v) All recertification tests shall be performed hands-off, as follows. No adjustments to the calibration of the CEMS, other than the adjustments described in section 2.1.3 of appendix B to this part, are permitted prior to or 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 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 this 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. 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 test, 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. 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;

(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, provided that the calibration error on the day of the failed 7-day calibration error test does not exceed twice the performance specification in section 3 of appendix A to this part; and

(D) If a calibration error test is failed (i.e., the results of the test exceed twice the performance specification in section 3 of appendix A to this part) during a recertification test period, 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. Previously-passed recertification tests in the sequence and previously-recorded conditionally valid data shall not be affected by a late 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 has been passed, re-establishing the conditionally valid status of data from the monitoring system.

(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 is 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 conditional 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. In addition, if the owner or operator submits any conditionally valid data (as defined in § 72.2 of this chapter) in any of the four quarterly reports for a given year, the owner or operator shall indicate the 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. 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.

(x) If the replacement, modification, or change requiring recertification of the CEMS is such that the data collected by the prior certified monitoring system are no longer representative, such as after a change to the flue gas handling system or unit operation that requires changing the span value to be consistent with section 2.1 of appendix A to this part, 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:

(A) 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

(B) For a change that results in a significantly lower concentration or flow rate, substitute data using the standard missing data procedures.

(C) 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.

(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 written notice of approval or disapproval 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 such 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) * * *

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

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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 monitor to a reference method.

(6) For each continuous moisture sensor:

(i) A 7-day calibration error test; and

(ii) 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.

(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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(9) * * *

(ii) Proper computation and application of the missing data substitution procedures in subpart D of this part and the bias adjustment factors in section 7 of appendix A to this part.

(10) The owner or operator shall provide, or cause to be provided, adequate facilities for initial certification or recertification testing that include:

*   *   *   *   *

(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 continuous emission monitoring system 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 continuous emission monitoring system 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 continuous emission monitoring system 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 monitoring system is not used to report emission data under this part. For any day on which a redundant backup monitoring system 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 continuous emission monitoring system shall comply with all of the following requirements for initial certification, quality assurance, recertification, and data reporting:

(i) For a non-redundant backup gas monitoring system that has its own separate probe, sample interface, and analyzer or for 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 non-redundant backup gas monitoring system consisting of one or more like-kind replacement analyzers that use the same probe and sample interface as a primary monitoring system, no initial certification of the non-redundant backup monitoring system is required. Note that a non-redundant backup analyzer, connected to the same probe and interface as a primary analyzer 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 considered a like-kind, non-redundant backup analyzer.

(iii) Each non-redundant backup monitoring system 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 monitoring system is used to report data, except that the requirements for when a linearity test must be performed are superseded by the requirements of this section. The owner or operator shall ensure that each non-redundant backup continuous emission monitoring system 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 non-redundant backup NO_X-diluent or SO_2-diluent monitoring system consisting of a primary pollutant analyzer and a like-kind replacement diluent analyzer (or vice-versa), provided that the primary analyzer 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 monitoring system 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 use of data retrospectively, as follows. Conditionally valid data from the CEMS 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 monitor other than those 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 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 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 CEMS remain invalid until the hour of completion of a successful linearity test.

(iv) When data are reported from a non-redundant backup monitoring system, the appropriate bias adjustment factor (BAF) shall be determined as follows:

(A) Apply the BAF from the most recent RATA of the non-redundant backup system (even if that RATA was done more than 12 months previously); or

(B) If no RATA results are available for the non-redundant backup system (e.g., for a non-redundant backup gas monitoring system that uses the same probe and sample interface as the primary monitoring system), apply the primary monitoring system BAF.

(v) A non-redundant backup system may not be used for reporting data from a particular affected unit or common stack for more than 720 hours in any one calendar year, unless the monitoring system passes a RATA at that same unit or stack.

(vi) For each non-redundant backup gas monitoring system that has its own separate probe, sample interface, and analyzer and for each non-redundant backup flow monitor, no more than eight successive calendar quarters shall elapse following the quarter in which the last RATA of the monitoring system was done at a particular unit or stack, without performing a subsequent RATA. Otherwise, the monitoring system may not be used to report data from that unit or stack until the hour of completion of a successful RATA at that location.

* * * * *

(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 the appropriate calibration procedures using one of the following standard methods: 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''; 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''; ASME MFC–9M–1988 with December 1989 Errata, ''Measurement of Liquid Flow in Closed Conduits by Weighing Method''; ISO 8316: 1987(E) ''Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank''; Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (1985 Edition); 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 calculation procedures of Part 3; or American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993), as required by appendices D and E to this part (all methods incorporated by reference under § 75.6).

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(2) *Initial certification and recertification testing notification.* The designated representative shall provide initial certification testing notification and periodic retesting notification for an excepted monitoring system under appendix E to this part as specified in § 75.61. The designated representative shall submit recertification testing notification, as specified in § 75.61, for quality assurance related NO_X emission rate 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.

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(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 ''continuous emission or opacity monitoring system'' shall be replaced with ''excepted monitoring system'' and except that ''shall follow the procedures for loss of initial certification in paragraph (a)(5)'' or ''shall follow the procedures of paragraph (b)(5)'' shall be replaced with ''shall follow the procedures for loss of certification in paragraph (g)(7)''. 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 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) *Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19.* The owner or operator of a gas-fired, oil-fired, or diesel-fired unit using the optional low mass emissions excepted methodologies under § 75.19 shall meet the applicable general operating requirements of § 75.10, the applicable requirements of § 75.19, and the applicable certification requirements of this paragraph (h).

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

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

(3) *Approval of certification applications.* Upon submission of the required certification application for approval to use the low mass emissions excepted methodology under § 75.19, the excepted methodology shall be deemed provisionally certified for use under the Acid Rain Program during the period for the Administrator's review. The provisions for the certification application formal approval process in the introductory text of paragraph (a)(4) and in paragraphs (a)(4)(i), (ii), and (iv) of this section shall apply, except that ''continuous emission or opacity monitoring system'' shall be replaced with ''excepted methodology.''

(4) *Disapproval of certification applications.* If the Administrator determines that the certification application does not demonstrate that the unit meets the requirements of §§ 75.19(a) and (b), the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification is invalidated by the Administrator, and the data recorded under the excepted methodology shall not be considered valid. The owner or operator shall follow the procedures for loss of certification:

(i) 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(e) (introductory paragraph) and 75.21(e)(1): the maximum potential concentration of SO_2, as defined in section 2.1 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; the maximum potential flow rate, as defined in section 2.1 of appendix A to this part to report volumetric flow; or the maximum CO_2 concentration used to determine the maximum potential concentration of SO_2 in section 2.1.1.1 of appendix A to this part to report CO_2 concentration data until such time, date, and hour as a continuous emission monitoring system or excepted monitoring system, where applicable, is installed and provisionally certified;

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

(iii) The owner or operator shall install and provisionally certify continuous emission monitoring systems or excepted monitoring systems, where applicable, no later than 180 unit operating days after the date of issuance of the notice of disapproval.

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

(1) *Initial certification and recertification testing.* The owner or operator shall, where applicable, use the

following procedures for certification and recertification of an excepted flow monitoring system under appendix I to this part.

(i) For an excepted flow monitoring system under appendix I to this part where each component is tested separately, perform the following tests on each O_2 or CO_2 component monitor:

(A) 7-day calibration error test;

(B) Linearity check;

(C) Cycle time test;

(D) Relative accuracy test audit using Test Method 3A from appendix A to part 60 of this chapter; and

(E) Bias test.

(ii) For an excepted flow monitoring system under appendix I to this part where each component is tested separately, meet the certification procedures under paragraph (g)(1)(i) of this section and the recertification procedures under paragraph (g)(6) of this section on each fuel flowmeter component using the standards specified, or meet the testing procedure under section 2.1.5.2 of appendix D to this part.

(iii) For an excepted flow monitoring system under appendix I to this part that is tested as an entire system, perform the following tests:

(A) 7-day calibration error test on the O_2 or CO_2 monitor,

(B) Linearity check on the O_2 or CO_2 monitor,

(C) Cycle time test on the O_2 or CO_2 monitor,

(D) Relative accuracy test audit on the entire excepted flow monitoring system under appendix I to this part, using Test Method 2 (or its allowable alternatives) from appendix A to part 60 of this chapter, and

(E) Bias test on the entire excepted flow monitoring system under appendix I to this part.

(iv) For the automated data acquisition and handling system used as part of an excepted flow monitoring system under appendix I to this part, the owner or operator shall perform tests designed to verify:

(A) The proper computation of hourly averages for volumetric flow rates, heat input, and pollutant mass emissions; and

(B) The proper computation and application of the missing data substitution procedures for volumetric flow in subpart D of this part.

(2) *Initial certification and recertification testing notification.* The designated representative shall provide initial certification and recertification testing notification for an excepted flow monitoring system under appendix I to this part, as specified in § 75.61, for any relative accuracy test audit.

(3) *Monitoring plan.* The designated representative shall submit a monitoring plan in accordance with §§ 75.53 and 75.62. For a unit that previously had a flow monitoring system or an excepted monitoring system under appendix D to this part and later submits a revised monitoring plan for an excepted flow monitoring system under appendix I to this part, the designated representative shall submit the revised monitoring plan no later than 45 days prior to the first day of certification testing.

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

(5) *Approval of initial certification and recertification applications.* Upon successful completion of the required initial certification or recertification procedures for each excepted monitoring system under appendix I to this part, each excepted monitoring system under appendix I 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 ''continuous emission or opacity monitoring system'' shall be replaced with ''excepted monitoring system'' and except that ''shall follow the procedures for loss of initial certification in paragraph (a)(5)'' or ''shall follow the procedures of paragraph (b)(5)'' shall be replaced with ''shall follow the procedures for loss of certification in paragraph (i)(7)''. Data measured and recorded by a provisionally certified excepted monitoring system under appendix I to this part will be considered quality assured data from the date and time of completion of the final certification test, provided that the Administrator does not revoke the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete initial certification or recertification application in accordance with the provisions in paragraph (a)(4) of this section.

(6) *Recertification requirements.* A recertification of an excepted flow monitoring system under appendix I to this part is required for any modification to the equipment used in the appendix I excepted flow monitoring system that would require recertification under paragraph (b) or (g) of this section.

(7) *Procedures for loss of certification for excepted monitoring systems under appendix I to this part.* In the event that a certification or recertification application is disapproved for an excepted monitoring system under appendix I to this part, data from the monitoring system are invalidated, and the applicable missing data procedures in section 4 of appendix I 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 (i)(2) of this section, and shall submit a new certification or recertification application according to the procedures in paragraph (i)(4) of this section.

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; revising newly designated paragraph (a)(9); and

c. Adding new paragraphs (a)(7), (a)(8), and (f), 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 continuous emission monitoring system meets the quality assurance requirements of § 75.20(d) for each day and quarter that the system is used to report data.

* * * * *

(4) When a unit combusts only natural gas or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas and SO_2 emissions are determined in accordance with § 75.11(e)(3), 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 natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content

of natural gas) is combusted in the unit. Notwithstanding, the results of any daily calibration error test and linearity test of the SO_2 monitoring system performed while the unit is combusting only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) shall be considered valid. If any such test is failed, the SO_2 monitoring system shall be considered to be 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 natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) is sometimes burned as a primary and/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 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 fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas, the SO_2 monitoring system is exempted from the relative accuracy test audit requirements in appendices A and B to this part. For the purposes of this part, a fuel having a total sulfur content no greater than 0.05 percent sulfur by weight shall be deemed to qualify as a ''fuel with a total sulfur content no greater than the total sulfur content of natural gas.''

(7) If the designated representative certifies that a particular unit with an SO_2 monitoring system combusts fuel(s) with a total sulfur content greater than the total sulfur content of natural gas (i.e., >0.05 percent sulfur by weight) only as emergency backup fuel(s) or for short-term testing, the SO_2 monitoring system shall be conditionally exempted from the RATA requirements of appendices A and B to this part, provided that the unit combusts the higher-sulfur fuel(s) for no more than 480 hours per calendar year. If, in a particular calendar year, the higher-sulfur fuel usage exceeds 480 hours, a RATA of the SO_2 monitor shall be performed (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 operating hour grace period following the quarter in which the exceedance occurs (see SO_2 RATA provisions in section 2.3.3 of appendix B to this part for further discussion of the grace period).

(8) On and after January 1, 2000, the quality assurance provisions of §§ 75.11(e)(3)(i) through 75.11(e)(3)(iv) shall apply (except that the term ''gaseous fuel'' shall be replaced with ''fuel'') to all units with SO_2 monitoring systems during hours in which only fuel having a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤0.05 percent sulfur by weight) is combusted in the unit, except for units that use such fuel only for unit startup.

(9) Provided that a unit with an SO_2 monitoring system is not exempted under paragraph (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 fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas (i.e. ≤0.05 percent sulfur by weight) 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 either by the end of the eighth successive elapsed calendar quarter since the last RATA or in the next calendar quarter in which a fuel with a total sulfur content greater than the total sulfur content of natural gas is burned in the unit.

* * * * *

(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 paragraph (a)(4)(iv) of § 75.20, 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), or an audit of any excepted monitoring system under appendix D, E, or I 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, an audit under § 75.20(a)(4)(iv), or another audit, the system is out-of-control. The owner or operator shall follow the procedures for out-of-control periods in § 75.24.

(f) *Excepted flow monitoring systems under appendix I.* The owner or operator of an affected unit shall operate, calibrate, and maintain each excepted flow monitoring system under appendix I to this part used under the Acid Rain Program according to the quality assurance and quality control procedures in appendices B and I to this part.

21. Section 75.22 is amended by revising paragraphs (a)(2), (a)(4), and (c)(1) introductory text to read as follows:

§ 75.22 Reference test methods.

(a) * * *

(2) Method 2 or its allowable alternatives, except for 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.

* * * * *

(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 paragraph (d) to read as follows:

§ 75.24 Out-of-control periods.

* * * * *

(d) When the bias test indicates that an SO_2 monitor, volumetric flow monitor, or NO_X continuous emission monitoring system 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 and in accordance with § 75.7.

* * * * *

23. Section 75.30 is amended by revising paragraphs (a)(2) and (d) to read as follows:

§ 75.30 General provisions.

(a) * * *

(2) A valid quality assured hour of flow data (in scfh) has not been measured and recorded for an affected unit from a certified flow monitor, or from a certified excepted flow monitoring system under appendix I to this part, or by an approved alternative monitoring system under subpart E of this part; or

* * * * *

(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 natural gas or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas.

(1) Whenever a unit with an SO_2 continuous emission monitoring system combusts only pipeline natural gas 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 continuous emission monitoring system combusts gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≥20 gr/100 scf) 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), 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 natural gas (or a gaseous fuel with total sulfur content no greater than the total sulfur content of natural gas), 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, 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 natural gas, or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas, 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 natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) 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 75.32 is amended by 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) * * *

(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 natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) from calculations of percent monitor data availability for SO_2 pollutant concentration monitors, as provided in § 75.30(d).

* * * * *

25. Section 75.33 is amended by adding a new paragraph (d) to read as follows:

§ 75.33 Standard missing data procedures.

* * * * *

(d) On and after January 1, 2000, failure to maintain a monitor data availability, as calculated pursuant to § 75.32, of at least 80.0 percent for SO_2, NO_X, flow rate, or CO_2 shall be considered a violation of the primary measurement requirement of § 75.10(a). This paragraph (d) shall not apply: if, for a particular unit or stack for which the monitor data availability drops below 80.0 percent, less than 3,000 unit operating hours have been accumulated in the previous 12 calendar quarters; or if a data availability percentage of less than 80.0 percent results from a sudden and reasonably unforeseeable event beyond the control of the owner or operator, such as catastrophic monitor failure or destruction of monitoring equipment by fire, flood, etc. If such circumstances have caused (or are projected to cause) the monitor data availability to drop below 80.0 percent, the owner or operator shall notify the Administrator, in writing, within 7 days of the event(s). Notification, in writing, shall also be provided to the EPA Regional Office and to the appropriate State agency. The written notifications shall fully explain the circumstances that have caused (or may cause) the low monitor data availability and shall contain an action plan and a projected time schedule for correction of the problem. Failures that are caused in part by poor maintenance or careless operation shall not, for the purposes of this paragraph, be considered reasonably unforeseeable events beyond the control of the owner or operator.

26. 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 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.

* * * * *

27. Section 75.35 is amended by revising paragraphs (a) and (c) to read as follows:

§ 75.35 Missing data procedures for CO_2 data.

(a) On and after January 1, 2000, the owner or operator of a unit with a CO_2 continuous emission monitoring system (or an O_2-diluent monitor that is used to determine CO_2 concentration in accordance with appendix F to this part) shall substitute for missing CO_2 concentration data using the procedures of this section. Prior to January 1, 2000, the owner or operator may substitute for missing CO_2 or O_2 concentration data using the procedures of this section.

* * * * *

(c) Upon completion of the first 720 quality assured monitor operating hours following initial certification of the CO_2 continuous emission monitoring system, the owner or operator shall provide substitute data for CO_2 concentration or CO_2 mass emissions required under this subpart, including CO_2 data calculated from O_2 measurements using the procedures in appendix F to this part, in accordance with the procedures in § 75.33(b), except that the terms ''SO_2 concentration'' and ''SO_2 pollutant concentration monitor'' shall be replaced, respectively, with ''CO_2 concentration'' and ''CO_2 pollutant concentration monitor.''

28. Section 75.36 is amended by revising paragraphs (a), (b), and (c) to read as follows:

§ 75.36 Missing data procedures for heat input.

(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 January 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 this section. Prior to January 1, 2000, the owner or operator may substitute for missing CO_2 or O_2 concentration data using the procedures in this section.

(b) During the first 720 quality assured monitor operating hours following initial certification (i.e., following the date and time of completion of successful certification tests of the CO_2 or O_2 monitor), 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) Upon completion of the first 720 quality assured monitor operating hours following initial certification of the CO_2 (or O_2) monitor, the owner or operator shall provide substitute data for CO_2 or O_2 concentration to calculate heat input according to the procedures in § 75.33(b), except that the term ''SO_2 concentration'' shall be replaced with ''CO_2 concentration'' or ''O_2 concentration'' (as applicable) and the term ''SO_2 pollutant concentration monitor'' shall be replaced with ''CO_2-diluent monitor'' or ''O_2-diluent monitor'' (as applicable).

* * * * *

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

§ 75.37 Missing data procedures for moisture.

The owner or operator shall substitute for missing moisture data (beginning no later than January 1, 2000 or the date and hour on which the unit or stack is required to begin reporting under § 75.64, whichever date is earlier) as follows:

(a) Where no prior quality assured percent moisture data exist, substitute 0.0 percent moisture for each unit operating hour;

(b) For the first 720 quality assured monitor operating hours, substitute for each hour of the missing data period the average of the percent moisture values obtained during the hour before and the hour after the missing data period;

(c) Once 720 quality assured monitor operating hours have been obtained, begin calculating the percent data availability of the moisture monitoring system, in accordance with § 75.32;

(d) When the percent data availability, as of the last hour in the missing data period, is ≥90.0 percent, substitute for each hour of the missing data period the average of the percent moisture values obtained during the hour before and the hour after the missing data period;

(e) If the percent data availability of the moisture monitor is < 90.0 percent as of the last hour in the missing data period, substitute 0.0 percent moisture for each hour of the missing data period.

Subpart E—[Amended]

30. Section 75.48 is amended by revising paragraphs (a)(3)(ii) and (a)(3)(iii) 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.

* * * * *

31. Section 75.50 is removed and reserved.

§ 75.50 [Removed and Reserved]

32. Section 75.51 is removed and reserved.

§ 75.51 [Removed and Reserved]

33. Section 75.52 is removed and reserved.

§ 75.52 [Removed and Reserved]

34. Section 75.53 is amended by revising paragraphs (a) and (b) and adding paragraphs (e) through (f) to read as follows:

§ 75.53 Monitoring plan.

(a) *General Provisions.*

(1) Compliance dates. Beginning on January 1, 2000, the owner or operator shall comply with the provisions in paragraphs (a), (b), (e) and (f) of this section only. Before January 1, 2000, the owner or operator shall comply with either paragraphs (a) through (d) or paragraphs (a), (b), (c), and (f) of this section, except that the owner or operator shall comply with provisions in paragraphs (e) and (f) of this section only before January 1, 2000, when those provisions support a regulatory option provided in another section of this part 75 and the regulatory option is exercised before January 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), as applicable) of this section, 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 continuous emission monitoring system, continuous opacity monitoring system, excepted methodology under § 75.19, excepted monitoring system under appendix D, E, or I 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.

* * * * *

(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.

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

(A) Short name;

(B) Classification of 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 date, 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, 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 continuous emission monitoring systems (i.e., SO_2 pollutant concentration monitor, flow monitor, moisture monitor; NO_X pollutant concentration monitor and diluent gas monitor), the continuous opacity monitoring system, or excepted monitoring system (i.e., 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 or method of operation, such as in situ pollutant concentration monitor or thermal flow monitor;

(D) Designation of the system as a primary, redundant backup, non-redundant backup, like kind 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; and

(F) Status of the monitoring component.

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

(A) For hardware components, the manufacturer and model number; and

(B) For software components, 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 to link continuous emission monitoring system or excepted monitoring system observations with reported concentrations, mass emissions, or emission rates, according to the conversions listed in appendix D, E, or F 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) Flue identification number, as reported to the Energy Information Administration (EIA).

(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.

(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 §§ 75.13 through 75.17.

(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 continuous emission monitoring system 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)(ii), (e)(1)(vi), and (e)(1)(vii) 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 in appendix I to this part for estimating stack flow rate, 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; and

(E) Monitoring system identification code.

(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 protocol for gaseous fuel in appendix D to this part, historical fuel sampling information on the sulfur content of the gaseous fuel according to section 2.3.3 of appendix D to this part.

(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.

(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) Conditional 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.

35. Section 75.54 is amended by adding new paragraphs (g) and (h) to read as follows:

§ 75.54 General recordkeeping provisions.

* * * * *

(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.

(h) *Compliance dates.* On January 1, 2000, the provisions of this section are no longer applicable. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.57. Beginning on January 1, 2000, the owner or operator shall comply with § 75.57 only.

36. Section 75.55 is amended by adding a new paragraph (g) to read as follows:

§ 75.55 General recordkeeping provisions for specific situations.

* * * * *

(g) *Compliance dates.* On January 1, 2000, the provisions of this section are no longer applicable. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.58. Beginning on January 1, 2000, the owner or operator shall comply with § 75.58 only.

37. Section 75.56 is amended by adding new paragraphs (a)(5)(vii) and (e) to read as follows:

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

(a) * * *

(5) * * *

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

* * * * *

(e) *Compliance dates.* On January 1, 2000, the provisions of this section are no longer applicable. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.59. Beginning on January 1, 2000, the owner or operator shall comply with § 75.59 only.

38. Section 75.57 is added to Subpart F to read as follows:

§ 75.57 General recordkeeping provisions.

(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 §§ 75.13 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 (f) 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 (f) 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:

(i) F-factor for heat input calculation; and

(ii) 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 (including the separate identification code for the moisture monitoring system, if applicable);

(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) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth), where SO_2 concentration is measured on a dry basis. If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, record both the wet- and dry-basis oxygen hourly averages (in percent O_2, rounded to the nearest tenth);

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

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

(3) 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 data in paragraphs (c)(1) and (c)(2) 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: SO_2: Method 6C. Flow: Method 2. NO_X: Method 7E. CO_2 or O2: 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, flow rate, or NO_X emission rate for the hour before and the hour following a missing data period.
7	Hourly average SO_2 concentration, CO_2 concentration, flow rate, or NO_X emission rate using initial missing data procedures.
8	90th percentile hourly SO_2 concentration, flow rate, or emission rate.
9	95th percentile hourly SO_2 concentration, flow rate, or NO_X emission rate.
10	Maximum hourly SO_2 concentration, flow rate, or NO_X emission rate.
11	Hourly average flow rate or NO_X emission rate in corresponding load range.
12	Maximum potential concentration of SO_2, maximum potential concentration of CO_2, maximum potential flow rate, or maximum potential NO_X emission rate, as determined using section 2.1 of appendix A to this part.
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, it shall be 5.0 percent for boilers and 1.0 percent for turbines; if it is replacing an O_2 measurement, it shall be 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 ppm during hours when only natural gas (or fuel with equivalent sulfur content) is combusted.
19	200.0 percent of the MPC; default high range value.
20	200.0 percent of the full-scale range setting (full-scale exceedance of high range).
40	Stack volumetric flow calculated using the procedures of appendix I.
54	Other quality assured methodologies approved through petition. These hours are included in missing data lookback and are included 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 included as unavailable hours for percent monitor availability calculations.

(d) *NO_X emission record provisions.* The owner or operator shall record the 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 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 concentration (ppm, rounded to the nearest tenth);

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

(5) Hourly average NO_X emission rate (lb/mmBtu, rounded either to the nearest hundredth or thousandth prior to January 1, 2000 and rounded to the nearest thousandth on and after January 1, 2000);

(6) Hourly average NO_X emission rate (lb/mmBtu, rounded either to the nearest hundredth or thousandth prior to January 1, 2000 and rounded to the nearest thousandth on and after January 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;

(7) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_X

monitoring system, and, if applicable, separately for the moisture monitoring system, calculated pursuant to § 75.32;

(8) Method of determination for hourly average NO_X emission rate using Codes 1–55 in Table 4a of this section;

(9) Identification code for emissions formulas used to derive hourly average NO_X emission rate and total NO_X mass, as provided in § 75.53, and 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 continuous emission monitoring system (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;

(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 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 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) *O_2-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, shall keep the following records for the O_2-diluent monitor:

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

(2) Date and hour;

(3) Hourly average O2 concentration (in percent, rounded to the nearest tenth);

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

(5) Method of determination code for O_2 concentration data using Codes 1–55, substituting the words ''O_2 concentrations'' and ''O_2 concentration'' for the words ''CO_2 concentrations'' and CO_2 concentration'' in the descriptions of Codes 6 and 7 in Table 4a of this section, respectively.

(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 cure such causes.

(i) Compliance dates. Beginning on January 1, 2000, the owner or operator shall comply with the provisions in paragraphs (a), (b), (e) and (f) of this section only. Before January 1, 2000, the owner or operator shall comply with either paragraphs (a) through (d) or paragraphs (a), (b), (c), and (f) of this section, except that the owner or operator shall comply with provisions in paragraphs (e) and (f) of this section only before January 1, 2000, when those provisions support a regulatory option provided in another section of this part 75 and the regulatory option is exercised before January 1, 2000.

39. Section 75.58 is added to read as follows:

§ 75.58 General recordkeeping provisions for specific situations.

(a) *Specific SO_2 emission record provisions for units with qualifying Phase I technology.* In addition to the SO_2 emissions information required in § 75.54(c), from January 1, 1997 through December 31, 1999, the owner or operator shall record the applicable information in this paragraph for each 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 and § 75.15.

(1) For units with post-combustion emission controls:

(i) Component/system identification codes for each inlet and outlet SO_2-diluent continuous emission monitoring system;

(ii) Date and hour;

(iii) Hourly average inlet SO_2 emission rate during unit operation (lb/mmBtu, rounded to nearest hundredth);

(iv) Hourly average outlet SO_2 emission rate during unit operation (lb/mmBtu, rounded to nearest hundredth);

(v) Percent data availability for both inlet and outlet SO_2-diluent continuous emission monitoring systems (recorded to the nearest tenth of a percent), calculated pursuant to Equation 8 of § 75.32 (for the first 8,760 unit operating hours following initial certification) and Equation 9 of § 75.32, thereafter; and

(vi) Identification code for emissions formula used to derive hourly average inlet and outlet SO_2 mass emissions rates for each affected unit or group of units using a common stack.

(2) For units with combustion and/or pre-combustion emission controls:

(i) Component/system identification codes for each outlet SO_2-diluent continuous emission monitoring system;

(ii) Date and hour;

(iii) Hourly average outlet SO_2 emission rate during unit operation (lb/mmBtu, rounded to nearest hundredth);

(iv) For units with combustion controls, average daily inlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth), determined by coal sampling and analysis procedures in § 75.15; and

(v) For units with pre-combustion controls (i.e., fuel pretreatment), fuel analysis demonstrating the weight, sulfur content, and gross calorific value of the product and raw fuel lots.

(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 petitioning to use or 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(b) or § 75.57(b) 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 1–55 in Table 4 of § 75.54 or 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 emission controls petitioning to use or 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 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 1–55 in Table 4 of § 75.54 or 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 petitioning under § 75.66 for substituting a representative SO_2 concentration during missing data periods, any available inlet and outlet SO_2 concentration values recorded by an SO_2 continuous emission monitoring system; and

(iv) For units petitioning under § 75.66 for substituting a representative NO_X emission rate during missing data periods, 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 flow rate of oil, while the unit combusts oil, with the units in which oil flow is recorded (gal/hr, lb/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) Method of oil sampling (flow proportional, continuous drip, as delivered, manual from storage tank, or daily manual);

(v) Mass rate of oil combusted each hour (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 (flag value if derived from missing data procedures);

(viii) Gross calorific value (heat content) of oil used to determine heat input (Btu/mass unit) (flag value if derived from missing data procedures);

(ix) Hourly heat input rate from oil, according to procedures in appendix F 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); and

(xi) Monitoring system identification code.

(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 nearest tenth of a percent).

(3) For gas-fired units or oil-fired units, using the optional protocol in appendix D to this part for using an assumed sulfur content or density, or for as-delivered fuel sampled from each delivery:

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

(ii) Record and report the assumed sulfur content, GCV 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 (rounded to the nearest 0.1 grains/100 scf) (flag value if derived from missing data procedures); or

(B) SO_2 emission rate from NADB or default SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas;

(iv) Hourly flow rate of gaseous fuel, while the unit combusts gas (100 scfh) (flag value if derived from missing data procedures);

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

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

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

(viii) 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

(ix) Monitoring system identification code.

(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) (flag value if derived from missing data procedures);

(iii) Gross calorific value or heat content (Btu/lb) (flag value if derived from missing data procedures); and

(iv) Density or specific gravity, if required to convert volume to mass (flag value if derived from missing data procedures).

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

(i) Date of sampling;

(ii) Sulfur content (grains/100 scf, rounded to the nearest tenth) (flag value if derived from missing data procedures);

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

(i) Date of sampling; and

(ii) Gross calorific value or heat content (Btu/100 scf) (flag value if derived from missing data procedures).

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

(i) Type of oil or gas; and

(ii) Type of sulfur sampling and value used in calculations.

(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), (d)(2)(vii), and (d)(3)(vi) 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 fuel flow rate of oil while the unit combusts oil with the units in which oil flow is recorded (gal/hour, lb/hr, or bbl/hour) (flag value if derived from missing data procedures);

(iii) Gross calorific value (heat content) of oil used to determine heat input (Btu/lb) (flag value if derived from missing data procedures);

(iv) Hourly average NO_X emission rate from combustion of oil (lb/mmBtu);

(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)); and

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

(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) (flag value if derived from missing data procedures);

(iii) Gross calorific value (heat content) 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)); and

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

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

(i) Date and hour;

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

(iii) Hourly average NO_X emission rate for the unit for all fuels;

(iv) 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);

(v) 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);

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

(vii) Segment ID of the correlation curve; and

(viii) Monitoring system identification code.

(4) For each fuel sample:

(i) Date of sampling;

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

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

(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 natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) is combusted in a unit with an SO_2 continuous emission monitoring system, 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)(3), 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 continuous emission monitoring system to determine SO_2 emissions during hours in which only natural gas or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas is combusted in the unit. If the unit sometimes burns only natural gas (or gaseous fuel with total sulfur content no greater than the total sulfur content of natural gas) 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 types of fuel was combusted in the unit during each missing data period. This recordkeeping requirement does not apply to an affected unit that burns natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) 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, 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 optional low mass emissions excepted methodology in § 75.19(c):

(1) Date and hour;

(2) 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 SO_2, CO_2, and NO_X);

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

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

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

(6) Hourly CO_2 mass emissions (tons, rounded to the nearest tenth).

(g) *Specific provisions for gas-fired units or oil-fired units using optional protocol in appendix I to this part.* In addition to recording the information in § 75.54(c) or § 75.57(c), as applicable, the owner or operator shall record the applicable information in this paragraph for each affected unit for which the owner or operator is using the optional protocol in appendix I to this part. This includes:

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

(i) Date and hour;

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

(iii) Method of oil sampling (flow proportional, continuous drip, as delivered, or manual);

(iv) Mass of oil combusted each hour (lb/hr, rounded to the nearest tenth);

(v) For units using volumetric oil flowmeters, density of oil (flag value if derived from missing data procedures);

(vi) Gross calorific value (heat content) of oil used to determine heat input (Btu/mass unit) (flag value if derived from missing data procedures);

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

(viii) Fuel usage time for combustion of oil during the hour (rounded up to the nearest 15 minutes).

(2) 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) Hourly flow rate of gaseous fuel (100 scfh) (flag value if derived from missing data procedures);

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

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

(vi) Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest 15 minutes); and

(vii) F-factor (F_c=Carbon-based F-factor of 1040 scf CO_2/mmBtu for natural gas, or F_d=Dry basis, O_2-based F-factor of 8,710 dscf/mmBtu for natural gas).

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

(i) Date of sampling;

(ii) Gross calorific value or heat content (Btu/lb) (flag value if derived from missing data procedures);

(iii) Density or specific gravity, if required to convert volume to mass (flag value if derived from missing data procedures); and

(iv) Percent carbon by weight.

(4) For each monthly sample of gaseous fuel:

(i) Date of sampling; and

(ii) Gross calorific value or heat content (Btu/100 scf) (flag value if derived from missing data procedures).

(5) Hourly average diluent gas concentration (percent O_2 or percent CO_2, rounded to the nearest tenth).

(h) *Compliance dates.* Beginning on January 1, 2000, the owner or operator shall comply with this section only. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.55; except that if a regulatory option provided in another section of this part 75 is exercised prior to January 1, 2000, then the owner or operator shall comply with any provisions of this section that support the regulatory option beginning with the date on which the option is exercised.

40. Section 75.59 is added to read as follows:

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

(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 monitor (including O_2 monitors used to determine CO_2 emissions), moisture sensor, 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, including any follow-up tests after corrective

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

(ii) Description of any adjustments, corrective actions, or maintenance following test.

(3) For each SO_2 or NO_X pollutant concentration monitor, CO_2 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) Date and hour;

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

(v) Observed value (average monitor response at each reference gas concentration, in ppm or other appropriate units);

(vi) Percent error at each of three reference gas concentrations (rounded to nearest tenth of a percent) (flag if using alternative performance specification);

(vii) Calibration gas level;

(viii) Mean of reference values and mean of measured values;

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

(x) Description of any adjustments, corrective action, or maintenance following test.

(4) For each flow monitor (where applicable) 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, and items in paragraphs (a)(4)(vi) and (vii) of this section, 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 following test;

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

(A) Component/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 BHR) and hourly ratios (or GHE 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; and

(L) Number of hours exempted for hours preceding a successful diagnostic test, following a documented monitor repair or major component replacement; and

(vii) Reference data for the flow-to-load ratio or gross heat rate evaluation, including:

(A) Reference flow RATA end date and time;

(B) Test number;

(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; and

(H) Reference gross heat rate value.

(5) For each SO_2 pollutant concentration monitor, flow monitor, CO_2 pollutant concentration monitor (including any O_2 concentration monitor used to determine CO_2 mass emissions or heat input), NO_X continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, moisture monitoring system, and 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 continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, moisture monitoring system, or approved alternative monitoring systems, including:

(A) Date, hour, and minute of beginning of test run;

(B) Date, hour, and minute of end of test run;

(C) 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) Run number;

(G) Run data for monitor, in the appropriate units of measure;

(H) Run data for reference method, in the appropriate units of measure;

(I) 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;

(J) Average gross unit load; and

(K) 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) 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.)

(E) Bias test results as specified in section 7.6.4 in appendix A to this part.

(F) Bias adjustment factor from Equations A–11 and A–12 in appendix A to this part for any monitoring system that failed the bias test (except as provided in section 7.6.5 of appendix A to this part) and 1.000 for any monitoring system that passed the bias test. (For multi-load RATAs of flow monitors only, when the bias test is passed at the load level(s) designated as normal in section 6.5.2.1 of appendix A to this part, the system BAF shall be recorded as 1.000. When the bias test is failed at any load level designated as normal in section 6.5.2.1 of appendix A to this part, bias adjustment factors shall be recorded at the two most frequently used load levels, as defined in section 6.5.2.1 of appendix A to this part.)

(iv) Description of any adjustment, corrective action, or maintenance following 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 flow polynomial equation used to linearize the flow monitor and the numerical values of the polynomial coefficients of that equation.

(6) For each SO_2, NO_X, CO_2, or O_2 pollutant concentration monitor, NO_X-diluent continuous emission monitoring system, or SO_2-diluent continuous emission monitoring system, 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; and

(ix) Cycle time result for the entire system.

(x) Reason for test.

(7) The owner or operator shall also record, for each relative accuracy test audit, supporting information sufficient to substantiate compliance with all applicable sections and appendices in this part. 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 absolute 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 axial velocity (ft/sec); and

(P) Total volumetric flow rate (scfh, wet basis).

(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) ΔP at traverse point (inches of H_2O);

(G) T_s, stack temperature at the traverse point (° F);

(H) Calculated impact (total) velocity at the traverse point (ft/sec);

(I) Composite (wall effects) traverse point identifier;

(J) Number of points included in composite traverse point;

(K) Yaw angle of flow at traverse point (degrees);

(L) Pitch angle of flow at traverse point (degrees); and

(M) Calculated axial velocity at traverse point (ft/sec).

(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) Reference gas concentration (zero, mid, or high gas levels) 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) The code for the formula used to convert reference method data to units of lb/mmBtu (if applicable);

(U) Date(s) of the latest analyzer interference test(s);

(V) Results of the latest analyzer interference test(s);

(W) Date of the latest NO_2 to NO conversion test (Method 7E only);

(X) Results of the latest NO_2 to NO conversion test (Method 7E only); and

(Y) For each calibration gas cylinder 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) Parameter (SO_2, NO_X, flow, CO_2, or H_2O), to indicate whether the moisture determination is used to support a gas or flow rate RATA or whether the determination is used to quality assure a moisture monitoring system;

(B) Test number;

(C) Run number;

(D) The beginning date, hour, and minute of the run;

(E) The ending date, hour, and minute or the run;

(F) Unit operating level (low, mid, high, or normal, as appropriate);

(G) Moisture measurement method;

(H) Volume of H_2O collected in the impingers (ml);

(I) Mass of H_2O collected in the silica gel (g);

(J) Dry gas meter calibration factor;

(K) Average dry gas meter temperature (°F);

(L) Barometric pressure (inches of mercury);

(M) Differential pressure across the orifice meter (inches of H_2O);

(N) Initial and final dry gas meter readings (ft^3);

(O) Total sample gas volume, corrected to standard conditions (dscf); and

(P) Percentage of moisture in the stack gas (percent H_2O).

(vi) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part) for the unit or common stack on which the continuous emission monitor(s) are installed, expressed in megawatts or thousands of lb/hr of steam;

(vii) The load level(s) designated as normal in section 6.5.2.1 of appendix A to this part for the unit or common stack on which the continuous emission monitor(s) are installed, expressed in megawatts or thousands of lb/hr of steam;

(viii) Except for peaking units, 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;

(ix) Except for peaking units, the relative frequency (percentage) of historical usage of each load level (low, mid, and high) in the previous four QA operating quarters, as determined in section 6.5.2.1 of appendix A to this part, to the nearest 0.1 percent. The beginning and ending calendar quarters in the historical look-back period shall also be recorded. A summary of the data used to determine the most frequently and second most frequently used load levels and the percentage of time that each load level has been used historically shall be kept on-site in a format suitable for inspection;

(x) Indication of whether the unit/stack qualifies for single load flow RATA testing (operation for ≥ 85.0 percent of operating hours is at a single load level); and

(xi) Date of the load analysis described in paragraphs (a)(7)(vi) through (a)(7)(x) of this section.

(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) Hardcopy quality assurance relative accuracy test reports, certification reports, or recertification reports for pollutant concentration or stack flow CEMS shall include, as a minimum, the following elements (as applicable to the type(s) of test(s) performed):

(i) Summarized test results near the front of the report;

(ii) DAHS printouts of the CEMS data generated during the calibration error, linearity, cycle time, and relative accuracy tests;

(iii) For pollutant concentration monitor relative accuracy tests at normal operating load:

(A) The raw reference method data from each run (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 and post-test quality assurance checks (i.e., calibration gas injections) of the reference method analyzers;

(C) The raw data and results for any moisture measurements made during the relative accuracy testing;

(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 flow monitor relative accuracy tests:

(A) The raw Reference Method 2 data, including auxiliary moisture data (often in the form of handwritten data sheets);

(B) The tabulated, final volumetric flow rate values used in the relative accuracy calculations (determined from the Method 2 data and other necessary measurements, e.g., moisture, stack temperature and pressure, etc.), 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 presented information in the monitoring plan). Include a discussion of any special traversing or measurement scheme. The discussion shall also confirm that sample points satisfied applicable acceptance criteria; and

(ix) Names of key personnel involved in the test program, including test team members, plant contacts, agency representatives or test observers on site, etc.

(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 elements in paragraph (a)(7)(ii) of this section, except for paragraphs (a)(7)(ii) (A), (F), (H), and (L);

(E) Data element in paragraph (a)(7)(iii)(A) of this section.

(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) Data elements in paragraph (a)(7)(iv) (B) through (I) and (L) through (O) of this section; 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:

(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;

(vii) Test code.

(12) For each quality assurance test extension or exemption request, the owner or operator shall record the following:

(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 fuel usage with a sulfur content >0.05 percent by weight; and

(G) Year to date hours of non-redundant back-up CEMS use at the unit/stack.

(ii) For a linearity test quarterly exemption:

(A) Component/system identification code; and

(B) Basis for exemption.

(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 or maximum allowable grace period if no quality assurance test was completed during the grace period; and

(E) Number of unit/stack operating hours from the beginning of the grace period to the completion of the quality assurance test or the maximum allowable grace period.

(13) An indication of which data have been excluded from the quarterly span and range evaluations of the SO_2 and NO_X monitors and the reasons for excluding the data, as required in sections 2.1.1.5 and 2.1.2.5 of appendix A to this part. For purposes of reporting under § 75.64(a)(1), 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 each oil-fired unit or gas-fired unit using the optional procedures of appendix D to this part for determining SO_2 mass emissions and/or heat input or the optional procedures of appendix E to this part for determining NO_X emission rate, for certification and quality assurance testing of fuel flowmeters tested against a reference fuel flow rate (i.e., flow rate 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) Date and hour of test completion;

(ii) Upper range value of the fuel flowmeter;

(iii) Flowmeter measurements during accuracy test (and mean of values), including units of measure;

(iv) Reference flow rates during accuracy test (and mean of values), including units of measure;

(v) Average flowmeter accuracy as a percent of upper range value for low, mid, and high fuel flowrates;

(vi) Indicator of whether test method was a lab comparison to reference meter or an in-line comparison against a master meter;

(vii) Test result (aborted, pass, or fail);

(viii) Component and system identification numbers of the fuel flowmeter being tested;

(ix) Date and hour fuel flowmeter was reinstalled (only for tests not performed inline); and

(x) 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) Date of test;

(ii) Full-scale value of the transmitter or transducer;

(iii) Transmitter input (pre-calibration) prior to accuracy test, including units of measure;

(iv) Expected transmitter output during accuracy test (reference value from NIST-traceable equipment), including units of measure;

(v) Actual transmitter output during accuracy test, including units of measure;

(vi) Transmitter or transducer accuracy as a percent of the full-scale value;

(vii) Transmitter output level as a percent of the full-scale value);

(viii) Transmitter or transducer accuracy, as a percent of full-scale value, and overall accuracy (if applicable), as a percent of upper range value;

(ix) Test and run number;

(x) Time of run (only for tests against another flowmeter inline);

(xi) Component and system identification numbers of the fuel flowmeter being tested;

(xii) Transmitter or transducer type (differential pressure, static pressure, or temperature); and

(xiii) Test result.

(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 2.1.6.6 of appendix D to this part:

(i) Date of inspection/test;

(ii) Hour of completion of inspection/test;

(iii) Component and system identification numbers 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 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 flow-to-load ratio or gross heat rate;

(D) Test result;

(E) Number of hours excluded due to co-firing;

(F) Number of hours excluded due to ramping;

(G) Number of hours excluded for lower 10.0 percent range of operation; and

(H) Quarterly average absolute percent difference between baseline ratio (or baseline GHR) and hourly quarterly ratios (or GHR value).

(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 and hour of baseline period;

(D) Completion date and hour of baseline period;

(E) Average fuel flow rate;

(F) Average load;

(G) Baseline fuel flow-to-load ratio and fuel flow-to-load units of measure;

(H) Baseline GHR and GHR units;

(I) Number of hours excluded due to ramping; and

(J) Number of hours excluded in lower 10.0 percent of range of operation.

(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;

(A) Run start date and time;

(B) Run end date and time;

(C) Fuel flow rate (lb/hr, gal/hr, scf/hr, bbl/hr, or m^3/hr);

(D) Gross calorific value (heat content) of fuel (Btu/lb or Btu/scf);

(E) Density of fuel, and units of measure for fuel density (if needed to convert mass to volume);

(F) Total heat input during the run (mmBtu);

(G) Hourly heat input rate for run (mmBtu/hr);

(H) Response time of the O2 and NO_X reference method analyzers;

(I) NO_X concentration (ppm);

(J) O_2 concentration (percent O_2);

(K) NO_X emission rate (lb/mmBtu);

(L) Fuel or fuel combination (by heat input fraction) combusted;

(M) Run number;

(N) Operating level;

(O) Elapsed time;

(P) Test number;

(Q) Monitoring system identification code for appendix E system, and oil or fuel flow system;

(R) Heat input from oil and/or gas during the run;

(S) Volumetric flow of oil and/or gas during the run, and units of measure for volumetric flow; and

(T) Mass fuel flow during the run.

(ii) For each unit load and heat input:

(A) Average NO_X emission rate (lb/mmBtu);

(B) F-factor used in calculations;

(C) Average heat input rate (mmBtu/hr);

(D) Unit operating parametric data related to NO_X formation for that unit type (e.g., excess O_2 level, water/fuel ratio);

(E) Fuel or fuel combination (by heat input fraction) combusted;

(F) Completion date and time of last run in level; and

(G) Arithmetic mean of reference method values at this level.

(c) For units with add-on SO_2 and 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 in appendix B to this part:

(1) A list of operating parameters for the add-on emission controls, including parameters in § 75.55(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 flow monitoring systems under appendix I.* The owner or operator shall record the applicable information in this section for each certified excepted flow monitoring system under appendix I to this part measuring and recording flow from an affected unit.

(1) *Certification test records.* Record the results of the following tests:

(i) For each CO_2 or O_2 component monitor:

(A) 7-day calibration error tests, as specified in paragraph (a)(1) of this section;

(B) Cycle time test, as specified in paragraph (a)(6) of this section; and

(C) Linearity checks, as specified in paragraph (a)(3) of this section.

(ii) For each appendix I flow monitoring system tested in a component by component assessment:

(A) Flowmeter accuracy test data (or a statement of calibration, if the flowmeter meets the accuracy standard by design), as specified in paragraph (b)(1) of this section;

(B) Relative accuracy test and bias data for the CO_2 (or O_2) monitor, as specified in paragraphs (a)(5) and (a)(7) of this section; and

(C) Fuel sampling and analysis data, as specified in section 2.3 of appendix I to this part.

(iii) For each appendix I flow monitoring system tested in a system relative accuracy assessment:

(A) Relative accuracy test and bias data for the appendix I flow monitoring system, as specified for a flow monitoring system in paragraphs (a)(5) and (a)(7) of this section; and

(B) Fuel sampling and analysis data, as specified in section 2.3 of appendix I to this part.

(2) *Quality assurance/quality control test records.* Record the results of the following tests:

(i) For CO_2 or O_2 monitors:

(A) Daily calibration error tests, as specified in paragraph (a)(1) of this section; and

(B) Quarterly linearity checks, as specified in paragraph (a)(3) of this section.

(ii) For each appendix I flow monitoring system tested in a component-by-component assessment:

(A) Flowmeter accuracy test data, as specified in paragraph (b)(1) or (b)(2) of this section and paragraph (b)(3) or (b)(4) of this section;

(B) Relative accuracy test and bias data for the CO_2 (or O_2) monitor, as specified in paragraphs (a)(5) and (a)(7) of this section; and

(C) Fuel sampling and analysis data, as specified in section 2.3 of appendix I to this part.

(iii) For each appendix I flow monitoring system tested in a system relative accuracy assessment:

(A) Relative accuracy test and bias data for the appendix I flow monitoring system, as specified for a flow monitoring system in paragraphs (a)(5) and (a)(7) of this section; and

(B) Fuel sampling and analysis data, as specified in section 2.3 of appendix I to this part.

(e) *Compliance dates.* Beginning on January 1, 2000, the owner or operator shall comply with this section only. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.56; except that if a regulatory option provided in another section of this part 75 is exercised prior to January 1, 2000, then the owner or operator shall comply with any provisions of this section that support the regulatory option beginning with the date on which the option is exercised.

41. 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 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) *Quality assurance 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 the quality assurance RATA report within 45 days after completing a quality assurance 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)(10) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the RATA report.

* * * * *

42. Section 75.61 is amended by revising paragraphs (a) introductory text, (a)(1) introductory text, and (b) 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 or I to this part, except as provided in paragraphs (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 requirement of paragraph (a)(1) of this section to provide it 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 enforce the requirement of paragraph (a)(1) of this section to provide it notice of recertification testing for future tests for a unit or a group of units.

* * * * *

(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.

* * * * *

43. Section 75.62 is amended by revising paragraphs (a) and (c) to read as follows:

§ 75.62 Monitoring plan.

(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: 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: 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).

* * * * *

(c) *Format.* Each monitoring plan shall be submitted in a format specified by the Administrator.

44. Section 75.63 is revised to read as follows:

§ 75.63 Initial certification or recertification application.

(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 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) of this section 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) of this section, the hardcopy information required by paragraph (b)(3) of this section, and a hardcopy certification application form (EPA form 7610–14) signed by the designated representative.

(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) of this section and by paragraph (b)(3) of this section.

(2) *Recertifications.* (i) Within 45 days after completing all recertification tests, submit to the Administrator the electronic information required by (b)(1) of this section and a hardcopy certification application form (EPA form 7610–14). Except for subpart E applications 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) of this section to the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency. The applicable EPA Regional Office or appropriate State or local air pollution control agency may waive the requirement 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 enforce the requirement of this paragraph (a)(2)(ii) 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 rather than a RATA, an accuracy test of the fuel flowmeter, or a retest of the appendix E NO_X correlation curve, no hardcopy submittal of any kind 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; these test results shall be kept on-site, 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.

(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)(10), 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.

(3) If the owner or operator is applying to use the optional low mass emissions excepted methodology in § 75.19(c) in lieu of a certified monitoring system,

(i) 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;

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

(iii) 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 (b).

(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)(10).

45. Section 75.64 is amended by revising paragraphs (a) introductory text, (d), and (e); by redesignating existing paragraphs (a)(1), (a)(2), (a)(3), (a)(4), (a)(5), and (a)(6) as paragraphs (a)(2), (a)(3), (a)(4), (a)(5),(a)(6) and (a)(8), respectively; by revising newly designated paragraphs (a)(2), and (a)(4); by adding new paragraphs (a)(1), (a)(7), (a)(9), (f), and (g); and by removing the third sentence in paragraph (c), 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), 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 (where the report contains 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 owner or operator recommences commercial operation of the unit (where the 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)(9) 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 data contained in the report; and

(C) EDR version 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:

(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)(9);

(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 January 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; and

(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 polynomial equations and numerical values required by § 75.56(a)(5)(vii) or § 75.59(a)(5)(vi);

(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)(ii), (iii), (iv), and (x), and (b)(2) 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 operational problems with the unit; and

(xiii) The summary of data used to determine the percentage of historical usage of each load level as required under § 75.59(a)(8)(iv).

(xiv) Supplementary RATA information required under §§ 75.59(a)(7)(iv)(A), (U), (V), (W), (X), and (Y).

* * * * *

(4) Average NO_X emission rate (lb/mmBtu, rounded to the nearest hundredth prior to January 1, 2000 and to the nearest thousandth on and after January 1, 2000) during the quarter and cumulative NO_X emission rate for the calendar year.

* * * * *

(7) Unit/stack/pipe operating hours for quarter and cumulative unit/stack/pipe operating hours for calendar year.

* * * * *

(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.

* * * * *

(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 2000, 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.

46. 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.

47. Section 75.66 is amended by revising paragraphs (a) and the first sentence of (e) introductory text; by redesignating paragraph (i) as paragraph (m) and revising it; and by adding paragraphs (i) through (l), 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 of this part. The designated representative shall include the following information in the petition:

(1) Identification of the affected 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) and/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 of 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 of 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) *Petition for an alternative to the maximum rated hourly heat input used to determine emissions under the low mass emissions excepted methodology in § 75.19.* The designated representative for an affected unit may submit a petition to the Administrator to use an alternative to the maximum rated hourly heat input to determine emissions under the low mass emissions excepted methodology set forth in § 75.19. The designated representative shall provide the following information:

(1) Identification of the affected unit(s);

(2) Information demonstrating that the maximum rated hourly heat input, as defined in § 72.2 of this chapter, is not representative of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently; and

(3) Information documenting that the proposed alternative maximum heat input is representative of the unit's highest potential heat input.

(m) *Any other petitions to the Administrator under this part.* Except for petitions addressed in paragraphs (b) through (l) 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 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.

48. Subpart H is added to read as follows:

Subpart H—NO_X Mass Emissions Provisions

Sec.

Subpart H—NO_X Mass Emissions Provisions

§ 75.70 NO_X mass emissions provisions.

(a) The owner or operator of a unit shall comply with the requirements of this subpart only if such compliance is required by an applicable state or federal NO_X mass emission reduction program that incorporates by reference, or otherwise adopts the requirements of, this subpart. For purposes of this subpart, the term ''affected unit'' shall mean any unit that is subject to a state or federal NO_X mass emission reduction program requiring compliance with this subpart, the term ''nonaffected unit'' shall mean any unit that is not subject to such a program, the term ''permitting authority'' shall mean the permitting authority under an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term ''designated representative'' shall mean the responsible party under the applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart. In addition, as set forth in this subpart, the provisions of subparts A, C, D, E, F, and G and appendices A through G applicable to NO_X emission rate and heat input shall apply to the owner or operator of a unit required to meet the requirements of this subpart by a state or federal NO_X mass emission reduction program, except that the term ''affected unit'' shall mean any unit that is subject to a state or federal NO_X mass emission reduction program requiring compliance with this subpart, the term ''permitting authority'' shall mean the permitting authority under an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term ''designated representative'' shall mean the responsible party under the applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(b) *Compliance dates.* The owner or operator of an affected unit shall meet the compliance deadlines established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(c) *Prohibitions.* (1) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with paragraph (g) of this section.

(2) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged emissions of NO_X to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this part.

(3) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other

approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this part.

(4) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this part, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption under § 96.5 that is in effect;

(ii) The owner or operator is monitoring NO_X mass emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of paragraph (d) of this section; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 75.73(d)(5).

(d) *Initial certification and recertification procedures.* (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of this part except that:

(i) The owner or operator shall meet any additional requirements set forth in an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(ii) For any additional NO_X emission rate CEMS required under the common stack provisions in § 75.72, the owner or operator shall meet the requirements of paragraph (d)(2) of this section.

(2) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart. The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall, for any additional NO_X emission rate CEMS required under the common stack provisions in § 75.72, comply with the initial certification and recertification procedures established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(e) *Quality assurance and quality control requirements.* The owner or operator shall meet the quality assurance and quality control requirements in § 75.21.

(f) *Missing data procedures.* Except as provided in § 75.34, the owner or operator shall provide substitute data for each affected unit and each non-affected unit under § 75.72(b)(2)(ii) using a continuous emissions monitoring system in accordance with the missing data procedures in subpart D of this part whenever the unit combusts fuel and:

(1) A valid quality assured hour of NO_X emission rate data (in lb/mmBtu) has not been measured and recorded for an affected unit or non-affected unit under § 75.72(b)(2)(ii) by a certified NO_X continuous emission monitoring system or by an approved monitoring system under subpart E of this part;

(2) A valid quality assured hour of flow data (in scfh) has not been measured and recorded for an affected unit or non-affected unit under § 75.72(b)(2)(ii) from a certified flow monitor or by an approved alternative monitoring system under subpart E of this part; or

(3) A valid quality assured hour of heat input data (in mmBtu) has not been measured and recorded for an affected unit from a certified flow monitor and a certified diluent (CO_2 or O_2) monitor or by an approved alternative monitoring system under subpart E of this part or by an accepted monitoring system under appendix D to this part.

(g) *Petitions.* (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart and with such state or federal NO_X mass emission reduction program only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (g)(1) of this section, petitions requesting an alternative to a requirement concerning any additional CEMS required solely to meet the common stack provisions of § 75.72, shall be submitted to the permitting authority and the Administrator and shall be governed by paragraph (g)(3)(ii) of this section. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(3)(i) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation may submit a petition to the permitting authority and the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(ii) Use of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that it is approved by both the permitting authority and the Administrator.

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

(a) *Coal-fired units.* The owner or operator of an affected unit shall meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system (including a NO_X pollutant concentration monitor and an O_2- or CO_2-diluent gas monitor) to measure NO_X emission rate and for a continuous flow monitoring system and an O_2- or CO_2-diluent gas monitor to measure heat input, except as provided by the Administrator in accordance with 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 (i.e., if the NO_X pollutant concentration monitor measures on a different moisture basis from the diluent monitor), the owner or operator of an affected unit shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in § 75.11(b).

(c) *Gas-fired nonpeaking units or oil-fired non-peaking units.* The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit but not as a peaking unit, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan shall either:

(1) Meet the requirements of paragraph (a) of this section and, if applicable, paragraph (b) of this section; or

(2) Meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system, except as provided, where applicable, in paragraph (e)(2) of this section or by the

Administrator in accordance with subpart E of this part, and use the procedures specified in appendix D to this part for determining hourly heat input. 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.

(d) *Peaking units that combust natural gas or fuel oil.* The owner or operator of an affected unit that combusts only natural gas or fuel oil and that qualifies as a peaking unit, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan shall either:

(1) Meet the requirements of paragraph (c) of this section; or

(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, a unit's operations exceed a capacity factor of 20.0 percent in any calender year or exceed a 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 calender year.

(e) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (c) and (d) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) shall comply with one of the following:

(1) Meet the applicable requirements specified in paragraph (c) or (d) of this section for monitoring NO_X emission rate and heat input; or

(2) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly emission rate, hourly heat input, and hourly NO_X mass emissions.

(f) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other materials shall comply with the monitoring provisions specified in paragraph (a) of this section and, where applicable, paragraph (b) of this section.

§ 75.72 Determination of NO_X mass emissions.

The owner or operator of an affected unit shall calculate hourly NO_X mass emissions (in lbs) by multiplying the hourly NO_X emission rate (in lbs/mmBtu) by the hourly heat input (in mmBtu/hr) and the hourly operating time (in hr). The owner or operator shall also calculate quarterly and cumulative year-to-date NO_X mass emissions and cumulative NO_X mass emissions for the ozone season (in tons) by summing the hourly NO_X mass emissions according to the procedures in section 8 of appendix F to this part.

(a) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:

(1) Record the combined NO_X mass emissions for the units exhausting to the common stack, install, certify, operate, and maintain a NO_X continuous emissions monitoring system in the common stack and:

(i) Install, certify, operate, and maintain a continuous flow monitoring system at the common stack; or

(ii) If all of the units using the common stack are eligible to use the procedures in appendix D to this part, use the procedures in appendix D to this part to determine heat input for each affected unit and use the combined heat input of all of the units exhausting to the common stack for calculating NO_X mass emissions; 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; or

(2) Install, certify, operate, and maintain a NO_X continuous emissions monitoring system in the duct to the common stack from each affected unit and:

(i) Install, certify, operate, and maintain a flow monitor in the duct to the common stack from each affected unit; or

(ii)(A) For any unit using the common stack and eligible to use the procedures in appendix D to this part, use the procedures in appendix D to determine heat input for that affected unit. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the mass reporting provisions of this subpart; and

(B) Install, certify, operate, and maintain a flow monitor in the duct to the common stack for each remaining affected unit.

(b) *Unit utilizing common stack with nonaffected unit(s).* When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X continuous emission monitoring system in the duct to the common stack from each affected unit; and

(i) Install, certify, operate, and maintain a continuous flow monitoring system in the duct to the common stack from each affected unit; or

(ii)(A) For any unit using the common stack and eligible to use the procedures in appendix D to this part, use the procedures in appendix D to determine heat input for that affected unit; however, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the mass reporting provisions of this subpart; and

(B) Install, certify, operate, and maintain a flow monitor in the duct to the common stack for each remaining affected unit that exhausts to the common stack; or

(2) Install, certify, operate, and maintain a NO_X continuous emission monitoring system in the common stack; and

(i) Designate the nonaffected units as affected units in accordance with the applicable state or federal NO_X mass emissions reduction program and meet the requirements of paragraph (a)(1) of this section; or

(ii)(A) Install, certify, operate, and maintain a continuous flow monitoring system in the common stack and a NO_X continuous emission monitoring system in the duct to the common stack from each nonaffected unit and either install, certify, operate, and maintain a continuous flow monitoring system in the duct from each nonaffected unit or, for any nonaffected unit exhausting to the common stack and otherwise eligible to use the procedures in appendix D to this part, determine heat input using the procedures in appendix D for that nonaffected unit (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), and for any remaining nonaffected unit that exhausts to the common stack, install, certify, operate, and maintain a flow monitor in the duct to the common stack; and

(B) Submit a petition to the permitting authority and the Administrator to allow a method of calculating and reporting the NO_X mass emissions from the affected units as the difference between NO_X mass emissions measured in the common stack and NO_X mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly value less than zero. The permitting authority and the

Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated; or

(iii) Install a continuous flow monitoring system in the common stack and record the combined emissions from all units as the combined NO_X mass emissions for the affected units for recordkeeping and compliance purposes; or

(iv) Submit a petition to the permitting authority and the Administrator to allow use of a method for apportioning NO_X mass emissions measured in the common stack to each of the units using the common stack and for reporting the NO_X mass emissions. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated.

(c) *Unit with bypass stack.* Whenever any portion of the flue gases from an affected unit can be routed to avoid the installed NO_X continuous emissions monitoring system, the owner and operator shall either:

(1) Install, certify, operate, and maintain a NO_X continuous emissions monitoring system and a continuous flow monitoring system on the bypass flue, duct, or stack gas stream and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by all required monitoring systems; or

(2) Monitor NO_X mass emissions on the bypass flue, duct, or stack gas stream using the reference methods in § 75.22(b) for NO_X concentration, flow, and diluent and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems.

(d) *Unit with multiple stacks.* Notwithstanding § 75.17(c), when the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks (which may include flue gases from other affected or nonaffected unit(s)), or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X continuous emission monitoring system and a continuous flow monitoring system in each duct feeding into the stack or stacks and determine NO_X mass emissions from each affected unit using the stack or stacks as the sum of the NO_X mass emissions recorded for each duct; or

(2) Install, certify, operate, and maintain a NO_X continuous emissions monitoring system and a continuous flow monitoring system in each stack, and determine NO_X mass emissions from the affected unit using the sum of the NO_X mass emissions recorded for each stack, except that where another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable requirements of paragraphs (a) and (b) of this section to determine and record NO_X mass emissions from the units using that stack; or

(3) If the unit is eligible to use the procedures in appendix D to this part, install, certify, operate, and maintain a NO_X continuous emissions monitoring system in one of the ducts feeding into the stack or stacks and use the procedures in appendix D to this part to determine heat input for the unit, provided that:

(i) There are no add-on NO_X controls at the unit;

(ii) The unit is not capable of emitting solely through an unmonitored stack (i.e., has no dampers); and

(iii) The owner or operator of the unit demonstrates to the satisfaction of the permitting authority and the Administrator that the NO_X emission rate in the monitored duct or stack is representative of the NO_X emission rate in each duct or stack.

§ 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), (d), and (g);

(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 flow rate of oil, while the unit combusts oil (in gal/hr, lb/hr, m^3/hr, or bbl/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) Mass rate of oil combusted each hour (in lb/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 (heat content) of oil used to determine heat input (in Btu/mass unit) (flag value if derived from missing data procedures);

(G) Hourly heat input rate from 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 GCV and, if applicable, density from each fuel sample; and

(B) Assumed GCV and, if applicable, 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 (heat content) of gaseous fuel used to determine heat input rate (in Btu/100 scf) (flag value if derived from missing data procedures);

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

(F) 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

(G) Monitoring system identification code;

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

(A) Date of sampling;

(B) Gross calorific value or heat content (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 or heat content (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 record 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), and (f)(4) in electronic format and the information in § 75.53(f)(1)(ii) and (f)(2)(ii) in hardcopy format.

(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 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(g).

(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)(10) 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 plans.* (1) *Submission.* (i) *Electronic.* 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)(1)(ii) 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:

(A) To the permitting authority, no later than 45 days prior to the initial certification test and at the time of recertification application submission; and

(B) To the Administrator, no later than 45 days prior to the initial certification test, at the time of recertification application submission, and in each electronic quarterly report.

(ii) *Hardcopy.* 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: 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).

(2) [Reserved]

(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 shall include the date of report generation, for the information provided in paragraphs (f)(1)(ii) through (f)(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*) EDR version used for the report;

(B) Location, including:

(*1*) Plant name and facility ID;

(*2*) EPA AIRS facility system ID;

(*3*) State facility ID;

(*4*) Source category/type;

(*5*) Primary SIC code;

(*6*) State postal abbreviation;

(*7*) 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/transducer accuracy tests;

(I) Stratification test results required as part of the RATA supplementary records under § 75.56(a)(7) or § 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) The summary of data used to determine the percentage of historical usage of each load level as required under § 75.59(a)(8)(iv);

(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 calender quarters, cumulative tons of NO_X emitted during the ozone season;

(v) During the second and third calender quarters, cummulative heat input for the ozone season; and

(vi) Unit/stack/pipe operating hours for quarter, cumulative unit/stack/pipe operating hours for calendar year, and, during the second and third calender quarters, cumulative operating hours during the ozone season.

(2) The designated representative shall affirm that the component/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).

Appendix A to Part 75—Specifications and Test Procedures

Appendix A—[Amended]

49.–53. Appendix A to part 75 is amended by revising section 2.1 to read as follows:

* * * * *

2. Equipment Specifications

2.1 Instrument Span and Range

In implementing sections 2.1.1 through 2.1.5 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, it is recommended that the range be selected 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. Note that this guideline does not apply to: (1) SO_2 readings obtained during the combustion of natural gas or fuel with a total sulfur content no greater than the total sulfur content of natural gas; (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 below, 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 fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 0.05 percent sulfur by weight), 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

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 results. 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.

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.

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).

$$\text{MPC (or MEC)} = 11.32 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{20.9 - \%O_{2w}}{20.9}\right)$$

(Eq. A–1a)

or

$$\text{MPC (or MEC)} = 66.93 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{\%CO_{2w}}{100}\right)$$

(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 the 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 percentage 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

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 with a total sulfur content no greater than the total sulfur content of natural gas, i.e., ≤ 0.05 percent sulfur by weight; or (3) fuels or blends that are used only for unit startup.

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).

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.

$$\text{MEC} = \text{MPC}\left(\frac{100 - RE}{100}\right)$$

(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 (percent).

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 value 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 MPC value from section 2.1.1.1 of this appendix. If the MEC is ≥20.0 percent of the MPC, 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 MPC, however, 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 MPC value from section 2.1.1.1 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 MPC, 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 MPC, however, 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 as follows: (1) designate the low and high monitor ranges as separate components of a single, primary monitoring system; or (2) designate the low and high monitor ranges as separate, primary monitoring systems; or (3) designate the normal monitor range as a primary monitoring system and the other monitor range as a non-redundant backup monitoring system; or (4) for units with SO_2 controls, if the default high range value is used, designate the low range analyzer as the primary monitoring system.

(e) Each monitoring system designated as primary shall meet the initial certification and quality assurance requirements for primary monitoring systems in § 75.20(c) 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).

(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 200.0 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 MPC (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 MPC, i.e., when the MEC of the fuel or blend being combusted is less than 20.0 percent of the MPC. 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 quarterly evaluation of the MPC, MEC, span, and range values for each SO_2 monitor and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a) through (e), below. Span and range adjustments may be required as a result of changes in the fuel supply, changes in the manner of operation of the unit, installation or removal of emission controls, etc. In implementing the provisions in paragraphs (a) through (e), below, note that 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 the analysis; however, if the high range is exceeded, 200.0 percent of the high range must still be reported as the hourly SO_2 concentration for each hour of the full-scale exceedance, as required by paragraph (c)(1) of this section. The owner or operator shall document all such unrepresentative operating conditions in the quarterly report required under § 75.64 and shall indicate which data (dates and hours) have been excluded from the quarterly span and range evaluation.

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) No span or range adjustment is required if, during a calendar quarter, the hourly SO_2 concentration exceeds the MPC but does not exceed the high span value. However, for missing data purposes, if any of the hourly SO_2 concentrations exceed the current MPC by ≥5.0 percent, a new MPC equal to the highest quality assured hourly SO_2 concentration recorded during the quarter must be defined in the monitoring plan. Update the monitoring plan to reflect the new MPC value.

(b) A span adjustment is required if any of the on-scale, quality assured hourly SO_2 concentrations exceed the high span value by ≤ 10.0 percent during a quarter, but do not exceed the high range. Define a new MPC value (as applicable) equal to the highest quality assured on-scale SO_2 concentration recorded during the quarter, and set the new span value according to section 2.1.1.3 of this appendix, using the new MPC value. If the new span value exceeds the current full-scale range, adjust the range setting also. Update the monitoring plan to reflect the new MPC, the new span value, and (if applicable) the new full-scale range. Where separate ranges are used to measure emissions from the combustion of different types of fuel, the low span and MEC shall be increased in the manner described in this paragraph if any on-scale hourly value exceeds the low span value by 10.0 percent or more.

(c) 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 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 (c)(1) of this section).

(d) 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. 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.

(e) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the SO_2 monitor, as described in paragraphs (a) through (d) 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 below, 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

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 below. Note that an initial MPC value determined for a unit that is not equipped with low-NO_X burners must be re-evaluated if a low-NO_X burner system is subsequently installed.

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.

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 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.

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.

For units with add-on NO_X controls, NO_X emission testing may only be used to determine the MPC if testing can be performed on uncontrolled emissions (e.g., measured at or before the control device inlet). 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 (e.g., the highest one-minute average) from all test runs as the MPC for NO_X.

If historical CEM data are used to determine the MPC, the data must 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 units with add-on NO_X controls, historical CEM data may only be used to determine the MPC if there are 720 quality assured monitor operating hours of CEM data measuring uncontrolled emissions (e.g., the CEM data are collected at or before the control device inlet). The highest hourly NO_X concentration in ppm shall be the MPC.

2.1.2.2 Maximum Expected Concentration

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 (i.e., 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.

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 3 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.

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)

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 ≤ 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 value may be required (see section 2.1.2.4 of this appendix).

If an existing state, local, or federal requirement for span of an 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.

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 MPC value determined in section 2.1.2.1 of this appendix. If the MEC values for all fuels (or blends) are ≥ 20.0 percent of the MPC, 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 MPC, two spans (low and high) are required, one based upon 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 as follows: (1) designate the low and high ranges as separate components of a single, primary monitoring system; or (2) designate the low and high ranges as separate, primary monitoring systems; or (3) designate the normal range as a primary monitoring system and the other range as a non-redundant backup monitoring system; or (4) for units with add-on NO_X controls, if the default high range value is used, designate the low range analyzer as the primary monitoring system.

(d) Each monitoring system designated as primary shall meet the initial certification and quality assurance requirements for primary monitoring systems in § 75.20(c) 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).

(e) For dual span units with add-on NO_X emission controls (i.e., 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 MPC, the low span value shall be based upon whichever MEC value is closest to 20.0 percent of the MPC. 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 MPC, i.e., when the MEC of the fuel being combusted is <20.0 percent of the MPC. 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 quarterly evaluation of the MPC, MEC, span, and range values for each NO_X monitor and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a) through (e), below. Span and range adjustments may be required as a result of changes in the fuel supply, changes in the manner of operation of the unit, installation or removal of emission controls, etc. In implementing the provisions in paragraphs (a) through (e), below, 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 the analysis; however, if the high range is exceeded, 200.0 percent of the high range must still be reported as the hourly NO_X concentration for each hour of the full-scale exceedance, in accordance with paragraph (c)(1) of this section. The owner or operator shall document all such unrepresentative operating conditions in the quarterly report required under § 75.64 and shall indicate which data have been excluded from the quarterly span and range evaluation.

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) No span or range adjustment is required if, during a calendar quarter, the hourly NO_X concentration exceeds the MPC but does not exceed the high span value. However, for missing data purposes, if any of the hourly NO_X concentrations exceed the current MPC by ≥ 5.0 percent, a new MPC equal to the highest quality assured hourly NO_X concentration recorded during the quarter must be defined in the monitoring plan. Update the monitoring plan to reflect the new MPC value.

(b) A span adjustment is required whenever any of the on-scale, quality assured, hourly NO_X concentrations exceed the high span value by ≥ 10.0 percent during a quarter but do not exceed the high range. Define a new MPC value (as applicable) equal to the highest quality assured on-scale NO_X concentration recorded during the quarter, and set the new span value according to section 2.1.2.3 or 2.1.2.4 of this appendix (as applicable), using the new MPC value. If the new span value exceeds the current full-scale range, adjust the range setting also. Update the monitoring plan to reflect the new MPC, the new span value, and (if applicable) the new full-scale range. Where separate ranges are used to measure emissions from different fuels or in different seasons (i.e. where seasonal controls are used), the low span and MEC shall be increased in the manner described in this paragraph if any on-scale hourly value exceeds the low span value by 10.0 percent or more.

(c) 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 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 (c)(1) of this section).

(d) 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. 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 ranges 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 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.

(e) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the NO_X monitor as described in paragraphs (a) through (d) 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. 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 $\geq$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).

2.1.3.2 Adjustment of Span and Range

Adjust the span value and range of a CO_2 or O_2 monitor according to the general guidelines in section 2.1.1.5 of this appendix (insofar as those provisions are applicable), replacing the term ''SO_2'' with ''CO_2 or O_2.'' Set the new span and range in accordance with section 2.1.3 of this appendix and provide a rationale for 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

Make an initial determination of 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 ft^2) at the flow monitor location.

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 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 2 significant figures. For calibration span values in inches of water, retain at least 2 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 units of scfh and, if different, in the units of calibration).

$$MPV = \left(\frac{F_d H_f}{A}\right)\left(\frac{20.9}{20.9 - \%O_{2d}}\right)\left(\frac{100}{100 - \%H_2O}\right)$$

(Eq. A–3a)

or

$$MPV = \left(\frac{F_c H_f}{A}\right)\left(\frac{100}{\%CO_{2d}}\right)\left(\frac{100}{100 - \%H_2O}\right)$$

(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 of this part,

F_c=carbon-based F factor ($scfCO_2$/mmBtu) from Table 1, Appendix F 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.

2.1.4.3 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a quarterly evaluation of the MPV, MPF, span, and range values for each flow rate monitor and shall make any necessary span and range adjustments with corresponding monitoring plan updates, as described in paragraphs (a) through (e), below. Span and range adjustments may be required 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, installation or removal of emission controls, etc. In implementing the provisions in paragraphs (a) through (e), below, 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 the analysis; however, if the high range is exceeded, 200.0 percent of the full-scale range must still be reported as the hourly flow rate for each hour of the full-scale exceedance, in accordance with paragraph (c) of this section. The owner or operator shall document all such unrepresentative operating conditions in the quarterly report required under § 75.64 and shall indicate which data have been excluded from the quarterly span and range evaluation. 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) No span or range adjustment is required if, during a calendar quarter, the hourly flow rate exceeds the MPF but does not exceed the flow rate span value. However, for missing data purposes, if any of the hourly flow rates exceed the current MPF by ≥5.0 percent, a new MPF equal to the highest quality assured hourly flow rate recorded during the quarter must be defined in the monitoring plan. Update the monitoring plan to reflect the new MPF value.

(b) A span adjustment is required whenever any of the on-scale, quality assured, hourly flow rates exceed the flow rate span value by ≥10.0 percent during a quarter. Define a new MPF equal to the highest on-scale flow rate recorded during the quarter, and set the new flow rate span value according to section 2.1.4.2 of this appendix. Then, calculate the new calibration span value by converting the new flow rate span value from units of scfh to units of daily calibration. If the new flow rate span value exceeds the current full-scale range, adjust the range setting also. Update the monitoring plan to reflect the new span and (if applicable) range values.

(c) 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 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.

(d) 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. 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.

(e) Whenever changes are made to the MPV, MPF, full-scale range, or span value of the flow monitor, as described in paragraphs (a) through (d) 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 Moisture Sensors

The span value of a continuous moisture sensor shall be equal to the full-scale range of the instrument. The range shall be selected in accordance with the requirements of section 2.1 of this appendix.

* * * * *

54. Section 3 of appendix A to part 75 is amended by revising section 3.1 and the last sentence in the first paragraph of section 3.2; by adding a new section 3.3.6; and by revising section 3.5, to read as follows:

3. Performance Specifications

3.1 Calibration Error

The initial 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. The calibration error of a continuous moisture sensor shall not exceed 3.0 percent of the span value, as calculated using Equation A–5 of this appendix.

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 * * *

3.3.6 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) are within ±1.0 percent H_2O.

* * * * *

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.

55. Section 4 of appendix A to part 75 is amended by revising the introductory paragraph and paragraph (6) to read as follows:

4. Data Acquisition and Handling Systems

Automated data acquisition and handling systems shall: (1) Read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) 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.

56. Section 5 of appendix A to part 75 is amended by revising sections 5.1, 5.2.1, 5.2.2, 5.2.3, and 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 above address, 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 above address, for a list of vendors and cylinder gases.

5.1.4 EPA Protocol Gases

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.

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, Attn: Berne Bennett, 919–541–2366.

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.

* * * * *

5.2.1 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.

57. Section 6 of appendix A to part 75 is amended by revising sections 6.2, 6.3.1, 6.5, 6.5.1, 6.5.2, 6.5.6, 6.5.7, and 6.5.9 to read as follows:

6. Certification Tests and Procedures

* * * * *

6.2 Linearity Check

For the purposes of initial certification, recertification, and quality assurance, 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 ≤30 ppm, that range is exempted from the linearity test requirements of 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. 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 tests on the range(s) and at the frequency specified in section 2.2.1 of appendix B to this part.

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. The linearity check must be done hands-off, as follows. No adjustments other than the calibration adjustments described in section 2.1.3 of appendix B to this part are permitted prior to or during the linearity test period. 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, substitute the words ''initial certification'' for ''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.

6.3 * * *

6.3.1 Pollutant Concentration Monitor and CO_2 or O_2 Monitor 7-day Calibration Error Test

For the purposes of initial certification and recertification, measure the calibration error of each pollutant concentration monitor and CO_2 or O_2 monitor while the unit is combusting fuel at conditions of typical temperature and pressure (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 daily calibration error test procedures in this section 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 either the mid-level or high-level concentration, as specified in section 5.2 of this appendix. 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.

Calibration error tests are acceptable for monitor or monitoring system certification 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 CEMS during a 7-day calibration error 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 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, substitute the words ''initial certification'' for ''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).

* * * * *

6.5 Relative Accuracy and Bias Tests

For the purposes of initial certification, recertification, and quality assurance, perform the required relative accuracy test audits as follows for each CO_2 and SO_2 pollutant concentration monitor, each flow monitor, each NO_X continuous emission monitoring system, each O_2 monitor used to calculate heat input or CO_2 concentration, each moisture monitoring system, and each SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999:

(a) All relative accuracy test audits shall be done ''hands-off'', as follows:

(1) 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.

(2) For 2-level and 3-level flow monitor audits, no re-linearization of the monitor (i.e., changing of the polynomial coefficients) is permitted between load levels.

(b) 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.

(c) 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.

(d) 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 switch fuels and have both a high and low span value), 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.

(e) Record monitor or monitoring system output from the data acquisition and handling system.

(f) For initial certification and recertification RATAs and for the quality assurance RATAs required by § 75.20(d) or by section 2.3.1 of appendix B to this part, complete each single-load relative accuracy test audit within a period of 168 consecutive unit operating hours. 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 operating hours; however, if this is not possible, up to 720 consecutive unit operating hours may be taken to complete a multiple-load flow RATA.

(g) 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, substitute the words ''initial certification'' for ''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.

(h) For each SO_2 or CO_2 pollutant concentration monitor, each flow monitor, and each NO_X continuous emission monitoring system, calculate the relative accuracy, in accordance with section 7.4 of this appendix. In addition (except for CO_2 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) For the purposes of initial certification, recertification, and quality assurance, perform the required relative accuracy test audits for each SO_2 or CO_2 pollutant concentration monitor, each O_2 monitor, each NO_X continuous emission monitoring system, and each SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, 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) 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.

(d) Flow monitor recertification RATAs shall be done at three load level(s), unless otherwise specified in paragraph (b) of this section or unless otherwise approved by the Administrator.

6.5.2.1 Range of Operation and RATA Load Levels (Definitions)

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. The lower boundary of the range of operation of a unit shall be the minimum safe, stable load (or, for common-stacks, the lowest of the minimum safe, stable loads for any of the units discharging through the stack). 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: (1) the nameplate or rated capacity of the unit, less any physical or regulatory limitations or other deratings, or (2) 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.

The operating levels for relative accuracy test audits shall, except for peaking units, be defined as follows: (1) the low operating level shall be the first 30.0 percent of the range of operation; (2) the mid operating level shall be the middle portion (30.0 to 60.0 percent) of the range of operation; and (3) 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.

The provisions of this paragraph become effective January 1, 2000. This determination shall be made just prior to conducting the quality assurance RATAs required under section 2.3 of appendix B of this part (in the same calendar quarter in which the RATAs are conducted) but not required more frequently than once a year, if the RATA(s) are conducted semiannually. The owner or operator shall determine, for each unit or common stack (except for peaking units) the load level (low, mid or high) that is the most frequently used. In addition, the owner or operator shall determine which load level is the second most frequently-used. To make the determinations, the owner or operator shall construct a historical load frequency distribution (e.g., histogram), depicting the relative number of operating hours at each of the three load levels, low, mid and high. The frequency distribution shall be based upon all available data from the four most recent QA operating quarters, as defined in section 2.3.1.1 of appendix B of this part. The owner or operator shall use the frequency distribution to determine, to the nearest 0.1 percent, the percentage of the time that each load level (low, mid, high) has been used in the previous four QA operating quarters. A summary of the data used for these determinations shall be kept on-site in a format suitable for inspection and the results of the determinations shall be included in the electronic quarterly report under § 75.64.

Except for peaking units, the owner or operator shall designate the most frequently used load level as the normal load level for each unit (or combination of units, for common stacks). The owner or operator may also, if appropriate, designate the second most frequently used load level as an additional normal load level for the unit or stack. For peaking units, the entire operating load range shall be considered normal.

Beginning on January 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 also indicate in the electronic quarterly report: (1) the two load levels (low, mid, or high) that are the most frequently used, as determined under this section; (2) the relative (percent) historical usage of each load level, as determined under this section; and (3) the load level (or levels) designated as normal under this section.

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 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.

The following alternative reference method traverse point locations are permitted for moisture and gas monitor RATAs:

(a) For all moisture determinations, a single reference method point, located at least 1.0 meter from the stack wall, may be used.

(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 (i.e., 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 (c) 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, 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 one time at the location (according to the acceptance criteria of section 6.5.6.3(b) 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(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 O2) 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 ±5 ppm 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 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 or 6.5.6.2 of this appendix (as appropriate; see section 6.5.6(b)(4) 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, 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

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 (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). 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, 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 CEM data and corresponding reference method test results.

* * * * *

58. Section 7 of appendix A to part 75 is amended by revising the introductory text of section 7.2.1 and the term ''R'' following equation A–5 and by revising section 7.6.4; and by adding 4 paragraphs at the end of section 7.6.5 and a new section 7.7 to read as follows:

7. Calculations

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7.2 * * *

7.2.1 Pollutant Concentration and Diluent Monitors

For each reference value, calculate the percentage calibration error based upon instrument span for daily calibration error tests using the following equation:

* * * * *

(Eq. A–5)

Where:

R=Reference value of zero or upscale (high-level or mid-level, as applicable) calibration gas introduced into the monitoring system.

* * * * *

7.6.4 Bias Test

For gas monitoring systems, if the mean difference, 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. For flow monitor bias tests, if the mean difference, d, is greater than |cc| at any load level designated as normal under section 6.5.2.1 of this appendix, the monitor has failed to meet the bias test requirement.

7.6.5 * * *

For single-load RATAs of SO_2-and NO_X-diluent monitoring systems and for 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 or SO_2 CEMS installed on a low-emitting affected unit (i.e., average SO_2 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 be determined using Equation A–12, or a default BAF of 1.111 may be used.

For a 2-level flow RATA, if the RATA is passed but the bias test is failed at a load level designated as normal under section 6.5.2.1 of this appendix, use Equation A–12 to calculate the bias adjustment factor at both of the operating levels. For a 3-level flow monitor relative accuracy test audit, if the RATA is passed but the bias test is failed at a load level designated as normal under section 6.5.2.1 of this appendix, calculate bias adjustment factors only for the two most-frequently used load levels, as determined in section 6.5.2.1 of this appendix. For both 2-level and 3-level flow RATAs, whenever the bias test is failed at a load level designated as normal under section 6.5.2.1 of this appendix, apply the larger of the two calculated bias adjustment factors to subsequent flow monitor data using Equation A–11.

Each time a RATA is successfully completed 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.

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, and 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.

7.7 Reference Flow-to-Load Ratio or Gross Heat Rate

The owner or operator shall determine R_{ref}, the reference value of the ratio of flow rate to unit load, each time that a successful 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 January 1, 2000. The reference flow-to-load ratio shall be calculated as follows:

$$R_{ref} = \frac{Q_{ref}}{L_{avg}} \times 10^{-5}$$

(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.

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, Q_{ref} will be the sum of the total volumetric flow rates that discharge through all of the stacks. Round off the value of R_{ref} to 2 decimal places.

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:

$$(GHR)_{ref} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000$$

(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.

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.

* * * * *

59. Section 1 of appendix B to part 75 is revised as follows:

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

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, E, or I 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, E, and I of 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 flow monitor polynomial coefficients, 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, assumed moisture content, 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_2 or NO_X missing data period.

1.3 Specific Requirements for Excepted Systems Approved under Appendices D, E, and I

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 § 75.20(g) 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., boroscope), 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 maintain 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.

1.3.7 Appendix I Additional Requirements

1.3.7.1 For all appendix I systems, the fuel sampling and analysis requirements in section 1.3.5 of this appendix shall be met; and, for the diluent monitor, the Calibration Error Test and Linearity Check Procedures requirements in sections 1.2.1 and 1.2.2 of this appendix shall be met.

1.3.7.2 For appendix I systems that are certified according to the system certification procedures, the Relative Accuracy Test Audit Procedures requirement in section 1.2.3 of this appendix shall be met for the annual or semiannual Method 2 flow RATA.

1.3.7.3 For appendix I systems that are certified according to the component-by-component certification procedures, the fuel flowmeter requirements applicable to the type of fuel flowmeter used in sections 1.3.1 through 1.3.5 of this appendix shall be met. The Relative Accuracy Test Audit Procedures requirement in section 1.2.3 of this appendix shall be met for the diluent monitor that is part of the appendix I system.

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.

60. Section 2 of appendix B to part 75 is amended by:

a. Revising sections 2.1.1, 2.1.3, 2.1.4, 2.2, 2.3; revising paragraph (1) of section 2.1.5.1;

b. Redesignating existing section 2.4 as section 2.5; and

c. Adding a new section 2.4, 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. For continuous moisture sensors, follow the manufacturer's recommended procedures for the daily calibration error check. Include the calibration procedures as part of the quality assurance program required under section 1 of this appendix.

* * * * *

2.1.3 Additional Calibration Error Tests and Calibration Adjustments

In addition to the daily calibration error tests required under section 2.1.1 of this appendix, a calibration error test of a CEMS shall be performed in accordance with section 2.1.1 of this appendix, as follows: (1) whenever a daily calibration error test is failed; (2) 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; and (3) after making certain calibration adjustments, as described in this section. In all cases, data from the CEMS are considered invalid until the required additional calibration error test has been successfully completed.

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.

Additional (non-routine) calibration adjustments of a monitor are permitted, 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.

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 ≤0.02 inches of water. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour following the hour of completion of a successful calibration error test. Note, however, that if the 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 2 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 continuous emission monitoring system, perform the following quarterly assessments. This requirement is effective 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. A QA operating quarter is a calendar quarter in which the unit operates (i.e., combusts fuel) for at least 168 hours or, for common stacks and bypass stacks, a calendar quarter in which flue gases are discharged through the stack for at least 168 hours. 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 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 routine quality assurance linearity test shall not be commenced if the monitoring system is operating out-of-control with respect to any of the daily, quarterly, or semiannual quality assurance assessments required by sections 2.1, 2.2, 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) Linearity checks shall be done hands-off, as follows. No adjustments of the monitor are permitted prior to or during the linearity test period, other than the routine and non-routine calibration adjustments described in section 2.1.3 of this appendix. The non-routine adjustments are permitted only prior to the test, not during the test period.

(c) If a daily calibration error test is failed during a linearity test period, prior to completing the test, the linearity test is invalidated and 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 re-commenced until the monitor has successfully completed a calibration error test.

(d) 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 CEMS. 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. 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).

(e) No more than four successive calendar quarters shall elapse after the quarter in which a linearity check of a CEMS (or range of a CEMS) 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 ''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.

(f) 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.

(g) 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) 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. However, a record of all linearity tests and 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

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 CEMS, four successive calendar quarters have elapsed after the quarter in which a linearity check of a CEMS (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 in which to perform a linearity test or leak check of that CEMS (or range). The grace period begins with the first unit 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.

If, at the end of the 168 unit 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 CEMS (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 grace period is used.

2.2.5 Flow-to-Load Ratio or Gross Heat Rate Evaluation

For each installed flow rate monitoring system on each unit or common stack, the owner or operator shall evaluate the flow-to-load ratio quarterly, i.e., for each QA operating quarter, as defined in sections 2.2.1 and 2.3.1.1 of this appendix. At the end of each QA operating quarter, the owner or operator shall use Equation B–1 in this appendix to calculate the flow-to-load ratio for every hour during the quarter in which: (1) 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 (2) a quality assured hourly average flow rate was obtained with a certified flow rate monitor.

$$R_h = \frac{Q_h}{L_h} \times 1000$$

(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.

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 or monitors its emissions in multiple breechings, Qh will be the combined hourly volumetric flow rate for all of the stacks or ducts. Round off each value of R_h to 2 decimal places.

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 CEMS or reference method. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000$$

(Eq. B–1a)

Where:

$(GHR)_h$ = 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.

In Equation B–1a, the owner or operator may either use bias-adjusted flow rates or unadjusted flow rates in the calculation of (Heat Input)h, provided that all of the heat input values are determined in the same manner.

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 hours of data. 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.

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.

$$E_h = \frac{\left|R_{ref} - R_h\right|}{R_{ref}} \times 100$$

(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 ± 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.

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.

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: (i) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥50 megawatts (or ≥500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; (ii) 10.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥50 megawatts (or ≥500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations; (iii) 20.0 percent, if L_{avg} for the most recent normal-load flow RATA is <50 megawatts (or <500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or (iv) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is <50 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: (a) implement Option 1 in section 2.2.5.1 of this appendix; (b) perform a RATA in accordance with Option 2 in section 2.2.5.2 of this appendix; or (c) 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.

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) Any hour in which an 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) If a normal-load flow RATA was performed and passed during the quarter being analyzed, any hour prior to completion of that RATA; and

(5) 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.

After identifying and excluding all non-representative hourly data in accordance with (1) through (5) above, 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.

If, after re-analyzing the data, E_f meets the applicable limit in (i),(ii), (iii), or (iv), above, 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 one week of the end of the calendar quarter for which the flow-to-load (or GHR) evaluation indicates noncompliance, investigate and troubleshoot each flow monitor for which E_f has been found to be above the applicable limit. 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), 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 shall then either: (1) complete the abbreviated flow-to-load test in section 2.2.5.3 of this appendix; or (2) perform a 3-level recertification RATA according to the recertification test period and data validation procedures of § 75.20(b)(3), if the corrective action has affected the linearity of the flow monitor (e.g., by requiring changes to the flow monitor polynomial coefficients).

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 successfully completed.

2.2.5.3 Abbreviated Flow-to-Load Test

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) 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.

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 6 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 3 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.

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 2.2.5.1 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, in accordance with the recertification test period and data validation procedures of § 75.20(b)(3).

2.3 Semiannual and Annual Assessments

For each primary and redundant backup continuous emission monitoring system, perform relative accuracy assessments either semiannually or annually, as specified in subsection 2.3.1.1 or 2.3.1.2, below, for the type of test and the performance achieved. This requirement is effective as of the calendar quarter following the calendar quarter in which the continuous emission 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

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 for each primary and redundant backup SO_2 pollutant concentration monitor, flow monitor, CO_2 pollutant concentration monitor (including O2 monitors used to determine CO_2 emissions), moisture monitoring system, NO_X-diluent continuous emission monitoring system, or SO_2-diluent continuous emission monitoring system used by units with a Phase I qualifying technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999. A QA operating quarter is a calendar quarter in which the unit operates for at least 168 hours or, for a common stack or bypass stack, a calendar quarter in which flue gases are discharged through the stack for at least 168 hours. 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 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.

The relative accuracy test audit frequency of a CEMS may be reduced, as specified in subsection 2.3.1.2, below, 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 subsections 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 O2 monitors used to determine CO_2 emissions), moisture monitors, flow monitors, or NO_X-diluent 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: (1) the relative accuracy during the audit of an SO_2 or CO_2 pollutant concentration monitor (including an O2 pollutant monitor used to measure CO_2 using the procedures in appendix F to this part) or of a NO_X-diluent or SO_2-diluent continuous emissions monitoring system is ≤7.5 percent; (2) prior to January 1, 2000, the relative accuracy during the audit of a flow monitor is ≤10.0 percent at each operating level tested; (3) 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; (4) on low flow (≤10.0 fps) stacks/ducts, when flow monitor achieves a relative accuracy ≤7.5 percent (10.0 percent if prior to January 1, 2000) during the audit or when the monitor mean, calculated using Equation A–7 in appendix A to this part, is within ±1.5 fps of the reference method mean; (5) on low SO_2 emitting units (average SO_2 concentrations 250 ppm, or average SO_2 emission rate 0.500 lb/mmBtu for SO_2-diluent continuous emission monitoring systems), when the CEMS achieves a relative accuracy ≤7.5 percent during the audit or when the monitor mean value from the RATA is within ± 12 ppm (or 0.025 lb/mmBtu for SO_2-diluent continuous emission monitoring systems) of the reference method mean value; (6) on low NO_X emitting units (average NO_X emission rate ≤0.200 lb/mmBtu), when the NO_X continuous emission monitoring system achieves a relative accuracy ≤7.5 percent or when 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; (7) for a CO_2 or O2 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 O2; and (8) 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 ±0.7 percent H2O.

2.3.1.3 RATA Load Levels

(a) For SO_2 pollutant concentration monitors, CO_2 pollutant concentration monitors (including O_2 monitors used to determine CO_2 emissions), moisture monitoring systems, and SO_2-diluent and NO_X-diluent monitoring systems, the required 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 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. When a flow monitor qualifies for an annual RATA frequency under section 2.3.1.2 of this appendix, the annual 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. The annual 2-load flow RATA may be performed alternately with a single-load flow RATA at the most frequently used (normal) load level if the flow monitor is on a semiannual RATA frequency. In addition, a single-load flow RATA, at the most frequently used load level, may be performed in lieu of the 2-load RATA if, for the four QA operating quarters prior to the quarter in which the RATA is performed, the historical load frequency distribution determined under section 6.5.2.1 of appendix A to this part shows that the unit has operated at the most frequently used load level for ≤85.0 percent of the time. Finally, 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, and a 3-load RATA is required whenever a flow monitor is re-linearized, i.e., when one or more of its polynomial coefficients are changed. 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.

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 routine quality assurance 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) All RATAs must be done hands-off, as follows. No adjustment of the monitor's calibration is permitted prior to or during the RATA test period, other than the adjustments described in section 2.1.3 of this appendix. The non-routine calibration adjustments described in section 2.1.3 of this appendix are permitted only prior to the RATA, not during the test period. For 2-level and 3-level flow monitor audits, no linearization of the monitor is permitted in-between load levels.

(c) For single-load RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA is invalidated and 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 RATA. The subsequent RATA shall not be re-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 is invalidated; the results of any previously-passed RATA(s) at the other load level(s) are unaffected).

(d) 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 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. 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 (g) of this section).

(e) 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 CEMS, the RATA at that load level must be repeated. Data from the flow monitor are invalidated from the hour in which the test is failed or aborted and remain invalid until the successful completion of a RATA at the failed load level. 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 monitor is re-linearized, a subsequent 3-load RATA is required.

(f) 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 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. The out-of-control period for each monitoring system begins with the hour of completion of the failed CO_2 (or O_2) monitor RATA.

(g) 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 RATA; and all RATAs aborted due to a problem with the CEMS) 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. In addition, aborted RATA attempts that are part of the process of optimizing a monitoring system's performance do not have to be reported, provided that, in the period extending from the hour in which the test is aborted to the hour of commencement of the next RATA attempt: (1) no corrective maintenance or reprogramming of the monitoring system is done; and (2) only the calibration adjustments allowed under section 2.1.3 of this appendix are made. However, a record of all RATAs and RATA attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.

(h) Each time that a hands-off RATA of an SO_2 pollutant concentration monitor, a NO_X-diluent monitoring system, or a flow monitor is successfully completed, 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.

(i) Failure of the bias test does not result in the monitoring system being out-of-control.

2.3.3 RATA Grace Period

The owner or operator has a grace period of 720 consecutive unit operating hours in which to complete the required RATA for a particular CEMS, whenever: (a) a required RATA has not been performed by the end of the QA operating quarter in which it is due; (b) five consecutive calendar years have elapsed without a required 3-load flow RATA having been conducted; (c) 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 total sulfur content greater than the total sulfur content of natural gas exceeds 480 hours, for a unit which is conditionally exempted under § 75.21(a)(7) from the SO_2 RATA requirements of this part; or (d) eight successive calendar quarters have elapsed, following the quarter in which a RATA was last performed, without a subsequent RATA having been done, due to: (1) infrequent operation of the unit(s); (2) frequent combustion of fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤0.05 percent sulfur by weight) (SO_2 monitors, only); or (3) a combination of factors (1) and (2).

Except for SO_2 monitoring system RATAs, the grace period shall begin with the first unit 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 operating hour in which fuel with a total sulfur content greater than the total sulfur content of natural gas (i.e., >0.05 percent sulfur by weight) 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.

If, at the end of the 720 unit 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 (i.e., for reasons (a), (b), or (d) in this section), 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 grace period is used.

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, or NO_X continuous emission monitoring system 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, and RATA Deadlines

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 many instances, a required recertification test is the same type of test as one of the routine, periodic quality assurance tests required by this appendix (e.g., a linearity test or a RATA). When this occurs, the 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 test is successful, then, unless another recertification event occurs in that same QA operating quarter, it would not be necessary to perform a subsequent linearity test of the CEMS in that quarter. 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 in lieu of the procedures in this appendix.

Except as provided in section 2.3.3 of this appendix, whenever a successful RATA of a gas monitor or a successful 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 deadline for the next RATA 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 deadline for the next RATA. The results of a single-load flow RATA may be used to establish a RATA deadline when: (1) 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 (2) the single-load RATA is allowed for a unit that has operated at the most frequently used load level for ≥85.0 percent of the time, under section 2.3.1.3(c) of this appendix. No other single-load flow RATA may be used to establish an annual RATA frequency; however, a 2-load flow RATA may be performed in place of any required single-load RATA, in order to establish an annual RATA frequency.

2.5 Other Audits

* * * * *

61. Figures 1 and 2 at the end of appendix B are revised to read as follows:

FIGURE 1.—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, percent 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. ''Semiannual'' 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 RATAs at the two most frequently used loads. 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, in the past four QA operating quarters, 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.—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM

RATA	Semiannual[1] (percent)	Annual[1]
SO_2	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 lb/mmBtu [2]	RA ≤ 7.5% or ±0.015 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/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 ± 1.0% H_2O_2	RA ≤ 7.5% or ± 0.7% 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 in which the unit operates for < 168 hours (or, for common stacks and bypass stacks, exclude quarters in which gases discharge through the stack for < 168 hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 0.05 percent sulfur by weight) 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.

62. Section 2 of appendix C to part 75 is amended by revising sections 2.1 and 2.2.1 and by revising Table C–1 to read as follows:

Appendix C to Part 75—Missing Data Estimation Procedures

* * * * *

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) and NO_X emission rate (in lb/mmBtu).

2.2 * * *

2.2.1 For a single unit, establish 10 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	Hourly gross load*
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

*Percent of maximum hourly gross load or maximum hourly gross steam load (percent).

* * * * *

63. Section 1 of appendix D to part 75 is amended by revising section 1.1 to read as follows:

Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

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 emissions and heat input from:

(1) gas-fired units, as defined in § 72.2 of this chapter; or (2) oil-fired units, as defined in § 72.2 of this chapter. This optional SO_2 emissions data protocol contains procedures for conducting oil sampling and analysis in section 2.2 of this appendix; the procedures for oil sampling may be used for any gas-fired unit or oil-fired unit. In addition, this optional SO_2 emissions data protocol contains three procedures for determining SO_2 emissions due to the combustion of gaseous fuels having a total sulfur content no greater than 20 grains per 100 standard cubic foot.

* * * * *

64. Section 2 of appendix D to part 75 is amended by:

a. Revising section 2.1 *Flowmeter Measurements*;

b. Revising sections 2.2, 2.2.1, 2.2.3, 2.2.4, 2.2.6, and 2.2.8; and removing and reserving section 2.2.2;

c. Revising sections 2.3, 2.3.1, 2.3.1.3, 2.3.2; redesignating section 2.3.1.4 as 2.3.1.4.1 and revising it; and adding sections 2.3.1.4.1, 2.3.1.4.2, 2.3.1.4.3, and 2.3.3; and

d. Revising section 2.4.1; removing section 2.4.2; redesignating sections 2.4.3, 2.4.3.1, 2.4.3.2, and 2.4.3.3 as 2.4.2, 2.4.2.1, 2.4.2.2, and 2.4.2.3, respectively; revising newly designated sections 2.4.2, 2.4.2.1, and 2.4.2.3; and redesignating section 2.4.4 as 2.4.3.

2. Procedure

2.1 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 for gas in section 2.1.4.1 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 a portion of the flow greater than 5.0 percent of the annual average flow rate 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. The hourly average proportion of flow rate from the pipe diverting fuel away from the unit to total fuel usage by the unit may be determined by using fuel usage data from fuel flowmeters in a previous year or by using a method approved by the Administrator under the provisions of § 75.66(i).

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 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, 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 Flowmeter Used for Commercial Billing

A gas flowmeter used for commercial billing of pipeline natural gas may be used to measure, record, and report hourly fuel flow rate. A gas flowmeter used for commercial billing of pipeline natural gas 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: (1) the gas flowmeter is used for commercial billing under a contract, provided that the company providing the gas under the contract and each unit combusting the gas do not have any common owners and are not owned by subsidiaries or affiliates of the same company; (2) the designated representative reports hourly records of gas flow rate, heat input rate, and emissions due to combustion of pipeline natural gas; (3) the designated representative also reports hourly records of heat input rate for each unit, if the gas flowmeter is on a common pipe header, consistent with section 2.1.2 of this appendix; (4) the designated representative reports hourly records directly from the gas 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 (5) the designated representative identifies the gas flowmeter in the unit's monitoring plan.

2.1.5 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 either by design or by measurement under laboratory conditions by the manufacturer, by an independent laboratory, or by the owner or operator, or may 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 (1985 Edition); 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,'' from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993); or 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 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, and (3) a load point approximately equally spaced between the full and minimum unit operating loads. Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

$$ACC = \frac{|R - A|}{URV} \times 100$$

(Eq. D–1)

Where:

ACC = Flowmeter accuracy as a percentage of the upper range value, including all error from all parts of both flowmeters.
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).

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, 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 according to a standard incorporated by reference under section 2.1.5.1 of this appendix), report the results of flowmeter accuracy tests using Table D–1 below.

TABLE D–1.—TABLE OF FLOWMETER ACCURACY RESULTS

Measurement level (percent of URV)	Run No.	Time of run (HHMM)	Candidate flowmeter reading	Reference flow reading	Percent accuracy (percent of URV)
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:					
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, hour, and minute that the fuel flowmeter was reinstalled following the test.
[3] It is required to test at least at three different levels, from minimum to maximum.

2.1.6 Quality Assurance

Test the accuracy of each fuel flowmeter prior to use under this part and at least once every four fuel flowmeter QA operating quarters thereafter. A ''fuel flowmeter QA operating quarter'' is a unit operating quarter in which the unit combusts the fuel measured by the fuel flowmeter for more than 168 hours. 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.

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.

For orifice-, nozzle-, and venturi-type flowmeters (that are 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 (both standards incorporated by reference under § 75.6) or that have satisfied the initial certification test requirement by meeting an accuracy of 2.0 percent of the upper range value or less by comparison with another fuel flowmeter, following the procedures of section 2.1.5.2 of this appendix), perform a transmitter accuracy test once every four 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 2.1.6.6 of this appendix for periodic quality assurance.

Notwithstanding the requirements of this section, if the procedures of section 2.1.7 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

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 across the range of readings on the transmitter or transducer corresponding to normal unit operation. Determine either the accuracy of each individual transmitter or transducer of the orifice-, nozzle-, or venturi-type flowmeter according to section 2.1.6.2 of this appendix, or determine the accuracy of the entire orifice-, nozzle-, or venturi-type flowmeter according to section 2.1.6.3 of this appendix.

2.1.6.2 Transmitter or Transducer Accuracy Calculation

Calculate the flowmeter accuracy at each level across the range of readings on the transmitter or transducer corresponding to normal unit operation by using the following equation:

$$\mathrm{ACC} = \frac{|\mathrm{R} - \mathrm{T}|}{\mathrm{FS}} \times 100$$

(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.

2.1.6.3 Total Flowmeter Accuracy Calculation

Use the transmitter or transducer accuracy calculated from Equation D–1a to determine if each individual transmitter or transducer meets an accuracy of ± 1.0 percent of its full-scale range at each level. If one or more of the transmitters or transducers does not meet this accuracy at each level, then either: (1) follow the data validation procedures in section 2.1.6.5 of this appendix, or (2) determine the total flowmeter accuracy at each level, i.e. error in the volumetric flow rate, including all transmitters or transducers and the primary element, using the following equation:

$$\frac{dq_v}{q_v} = \left(K^2 + \left[\frac{-dP_f}{2P_f}\right]^2 + \left[\frac{d\Delta P}{2\Delta P}\right]^2 + \left[\frac{dT_f}{2T_f}\right] \right)^{1/2}$$

(Eq. D–1b)

Where:

dq_v/q_v=Error in the volumetric flow rate due to transmitter drift at a given level.

K=Original error resulting from installation of orifice (including all other variables). For an orifice-, nozzle-, or venturi-type flowmeter that was originally installed to the specifications of AGA Report No. 3 or ASME MFC–3M, as cited in section 2.1.5.1 of this appendix, an assumed value of 1.0 percent of the upper range value may be used for ''K'' if original error data or dimensional information from installation of the meter or other information on total installation error are not available.

dP_f=Average difference between static pressure transmitter reading(s) and reference static pressure reading(s) at a given level.

P_f=Average reference static pressure reading at a given level.

$d\Delta P$=Average difference between differential pressure transmitter reading(s) and reference differential pressure reading(s) at a given level.

ΔP = Average reference differential pressure reading at a given level.

dT_f=Average difference between temperature transmitter reading(s) and reference temperature reading(s) at a given level.

T_f=Average reference temperature reading at a given level.

Note: For gases, overall flow rate is directly related to pressure and is inversely related to temperature. Therefore, when performing this test on a gas fuel flowmeter, it is recommended that readings be entered into the equation at the following levels:

TABLE D–2—RECOMMENDED LEVELS FOR USING TRANSMITTER TEST RESULTS TO CALCULATE OVERALL GAS FLOWMETER ACCURACY

Level of total flow calculation	Level of static pressure reading	Level of differential pressure reading	Level of temperature reading
Low	Low	Low	High.
Mid	Mid	Mid	Mid.
High	High	High	Low.

If the overall flowmeter accuracy at each flow rate level is less than or equal to ± 2.0 percent of the upper range value of the fuel flowmeter, then the fuel flow rate data remain valid, and the data invalidation procedures of section 2.1.6.5 of this appendix are not required. If the overall flowmeter accuracy at any flow rate level is greater than ± 2.0 percent of the upper range value of the fuel flowmeter, then data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed accuracy test and continuing until the date and hour of a successful accuracy test for all transmitters or transducers; during the period when data from the fuel flowmeter are considered invalid, 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.

2.1.6.4 Recordkeeping and Reporting of Transmitter or Transducer Accuracy Results

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 Table D–3 below. 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–3.—TABLE OF FLOWMETER TRANSMITTER OR TRANSDUCER ACCURACY RESULTS

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)
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						
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).						
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).

In addition, when testing the whole orifice, nozzle, or venturi meter for accuracy, record the information displayed in Table D–1 above. At a minimum, record the overall flowmeter accuracy results for the entire fuel flowmeter at the zero-level and at least two other levels across the range of normal unit operation.

Report the final result of the accuracy test (pass or fail) for the combination of all transmitters or transducers of the orifice, nozzle or venturi meter in the emissions report of the quarter in which the accuracy is determined, using the electronic format specified by the Administrator under § 75.64.

2.1.6.5 Failure of Transducer or Transmitter

Except as provided in section 2.1.6.3 of this appendix, if the accuracy during a calibration or test of an individual transmitter or transducer is greater than ±1.0 percent of the full-scale range for that transmitter or transducer at any level or if the individual transmitter or transducer fails to operate properly, recalibrate the transmitter or transducer or replace the transmitter or transducer with another one until the transmitter or transducer accuracy is less than or equal to ±1.0 percent of the full-scale range for that transmitter or transducer, consistent with sections 2.1.6.1 and 2.1.6.2 of this appendix. Data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed accuracy test (or a failure to operate properly) for any transmitter or transducer and continuing until the date and hour of an accuracy test for all transmitters or transducers in which all transmitters or transducers meet an accuracy of ±1.0 percent of the full-scale range for that transducer or transmitter. 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. Record and report test data and results, consistent with section 2.1.6.4 of this appendix and § 75.56 or § 75.59, as applicable.

2.1.6.6 Primary Element Inspection

Conduct a visual inspection of the orifice, nozzle, or venturi 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 to at least once every twenty calendar quarters. The inspection may be performed using a boroscope. If the visual inspection indicates that the orifice, nozzle, or venturi 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. 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 2.1.6.4 of this appendix. 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 2.1.6.6 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 2.1.7.2 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 flowmeter QA operating quarter, as defined in section 2.1.6 of this appendix (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 2.1.6.6 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 2.1.6.6 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

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 section 2.1.5.1, 2.1.5.2, or 2.1.6.1 and 2.1.6.6 of this appendix. Establish a baseline period of data consisting, at a minimum, of 168 hours of quality assured fuel flowmeter data taken immediately after 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 the following data as non-representative: (1) 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 (2) any hour in which the unit load is in the lower 10.0 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 portion of the range is considered normal for the unit. The baseline data must be obtained no later than the end of the second 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 2.1.6.6 of this appendix, then the baseline data must be obtained after both procedures are completed and no later than the end of the second 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:

$$R_{base} = \frac{Q_{base}}{L_{avg}}$$

(Eq. D–1c)

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.

In Equation D–1c, 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.

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:

$$(GHR)_{base} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000$$

(Eq. D–1d)

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.

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

Evaluate the fuel flow rate-to-load ratio (or GHR) for each flowmeter QA operating quarter, as defined in section 2.1.6 of this appendix. At the end of each flowmeter QA operating quarter, use Equation D–1e 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.

$$R_h = \frac{Q_h}{L_h}$$

(Eq. D–1e)

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.

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.

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:

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000$$

(Eq. D–1f)

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.

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.

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–1g.

$$\%D_h = \frac{\left|R_{base} - R_h\right|}{R_{base}} \times 100$$

(Eq. D–1g)

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.

Consistently use R_{base} and R_h in Equation D–1g if the fuel flow-to-load ratio is being evaluated, and consistently use $(GHR)_{base}$ and $(GHR)_h$ in Equation D–1g if the gross heat rate is being evaluated.

Next, determine the arithmetic average of all of the hourly percent difference (percent D_h) values using Equation D–1h, as follows:

$$SO_{2_c} = \sum_{q=1}^{\text{the current quarter}} SO_{2_q}$$

(Eq. D–1h)

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.

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

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 shall be considered non-representative: (1) any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; (2) any hour for which the load differed by more than ± 15.0 percent from the load during either the preceding hour or the subsequent hour; and (3) any hour for which the unit load was in the lower 10.0 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 portion of the range is considered normal for the unit.

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-Ratio Test

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 2.1.6.6 of this appendix, and repair or replace the primary element, as necessary.

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 (for orifice-, nozzle-, or venturi-type fuel flowmeters, a new value of R_{base} or $(GHR)_{base}$ shall only be established 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–1h, in the electronic quarterly report required under § 75.64. Table D–4 is provided as a reference on the type of information to be recorded under § 75.59 and reported under § 75.64.

TABLE D–4.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST

Time period	
Baseline period	Quarter
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)	
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 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 10.0 percent of the range of operation excluded from quarterly average:_______hrs.

TABLE D–4.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST—Continued

Time period	
Baseline period	Quarter
____/____/____ ____:____ End date and time of baseline period: ____/____/____ ____:____ Average fuel flow rate:________ (100 scfh for gas and lb/hr for oil) Average load:________ (MWe or 1000 lb steam/hr)	Number of hours included in quarterly average:________hrs. Quarterly percentage difference between hourly ratios and baseline ratio:________ percent. Test result: pass, fail

Plant name:________ State:________ ORIS code:________

Unit/pipe ID#:________ Fuel flowmeter component and system ID #:____–____

Calendar quater (1st, 2nd, 3rd, 4th) and year:________

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

Time period	
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:________ hrs. Number of hours in the lower 10.0 percent of the range of operation excluded from baseline ratio or GHR:________ hrs.	

2.2 Oil Sampling and Analysis

Perform sampling and analysis of oil to determine the percentage of sulfur by weight in the oil combusted by the unit. Calculate SO_2 mass emissions and heat input rate using the sulfur content, density, and gross calorific value (heat content), as described in the sections below and in Table D–5.

TABLE D–5.—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	Highest sulfur content from previous 30 daily samples.
	Flow proportional/weekly composite..	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
Oil Density	Daily manual sampling	Actual measured value.
	Flow proportional/weekly composite..	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
Oil GCV	Daily manual sampling	Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	Highest of all sampled values in previous calendar year OR 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, sample the oil: (1) 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; (2) 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; (3) following the flow proportional sampling methodology in section 2.2.3 of this appendix; or (4) following 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 (ship load, barge load, group of trucks, discrete purchase of diesel fuel through pipeline, etc.), which meets the fuel purchase specifications for sulfur content and GCV. A storage tank is a container at a plant holding oil that is actually combusted by the unit, such that 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 hr). 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), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purpose of calculating SO_2 emissions under section 3 of this appendix. Use the gross calorific value measured from that day's 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. No additional fuel shall be blended 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: (1) the most recent oil sample taken or (2) one of the conservative assumed values described in section 2.2.4.3 of this appendix.

2.2.4.3 Sampling from Each Delivery

Alternatively, an oil sample may be taken from the shipment tank or container upon receipt of each lot of fuel oil or from the supplier's storage container which holds the lot of fuel oil. 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.) which meets the fuel purchase specifications for sulfur content and GCV. 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 2.2.4.3, calculate SO_2 mass emission rate using the sulfur content (and where required, the density) from one of the two values below, 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 or (2) the maximum value indicated in the contract with the fuel supplier unit. Continue to use this assumed value unless and until the actual sampled sulfur content, density, or gross calorific value of a delivery exceeds the assumed value.

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: (1) it is superseded by a higher value from an oil sample; (2) a new contract with a higher maximum sulfur content, gross calorific value, or density is adopted, in which case the new contract value becomes the assumed value; or (3) 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

Account for the hourly SO_2 mass emissions due to combustion of gaseous fuels for each day when gaseous fuels are combusted by the unit using the procedures in either section 2.3.1 or 2.3.2. The procedures in section 2.3.1 may be used for accounting for SO_2 mass emissions from any gaseous fuel with a total sulfur content ≤20.0 gr/100 scf. The procedures in section 2.3.2 may be used for pipeline natural gas or for any gaseous fuel for which the designated representative demonstrates to the satisfaction of the Administrator, in a petition to the Administrator under § 75.66(i), that the fuel has an SO_2 emission rate no greater than 0.0006 lb/mmBtu. Values used for calculations of SO_2 mass emission rates are summarized in Table D–6, below.

TABLE D–6.—GAS SAMPLING METHODS AND SULFUR AND HEAT CONTENT (GCV) VALUES USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations
Gas Sulfur Content	Gaseous fuel in lots—as-delivered sampling [1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract [1]
	Any gaseous fuel—daily sampling [2]	Highest sulfur in previous 30 daily samples.
	Any gaseous fuel—continuous sampling (at least hourly) with a gas chromatograph.	Actual measured hourly average sulfur content.
Gas GCV/heat content	Gaseous fuel in lots—as-delivered sampling [1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
	Gaseous fuels other than pipeline natural gas that are sampled for sulfur content—daily sampling.	Highest GCV in previous 30 daily samples.
	Gaseous fuels other than pipeline natural gas that are sampled for sulfur content—continuous sampling (at least hourly).	Actual measured hourly average GCV or highest GCV in previous 30 unit operating days.
	Pipeline natural gas—monthly sampling for GCV only.	Actual measured GCV OR highest of all sampled values in previous calendar year OR maximum value allowed by contract.[3]

[1] Assumed sulfur and GCV values may only continue to be used if sulfur content and gross calorific value of each as-delivered sample is no greater than the assumed value used to calculate emissions or heat input.

[2] Continuous sampling (at least hourly) may be required if the sulfur content exhibits too much variability (see section 2.3.3.4, below).
[3] Assumed GCV values of the highest sampled value in the previous calendar year or the maximum value allowed by contract may only continue to be used if gross calorific value of each monthly sample is no greater than the assumed value used to calculate heat input.

2.3.1 For gaseous fuels received in shipments or lots, sample each shipment or lot of fuel. A fuel lot for gaseous fuel is the volume of product gas from one source (supplier or pretreatment facility), intended as one shipment or delivery, which meets the fuel purchase specifications for sulfur content and GCV. For gaseous fuels, other than pipeline natural gas, that are not delivered in discrete lots or shipments, sample the gaseous fuel at least daily. Continuous sampling (at least hourly) with a gas chromatograph may be required if the sulfur content exhibits too much variability (see section 2.3.3.4, below). For gaseous fuel meeting the definition of pipeline natural gas in § 72.2 of this chapter, either use the procedures of section 2.3.2 of this appendix or sample the gaseous fuel at least daily. Sampling may be performed by either the owner or operator or by the fuel supplier.

* * * * *

2.3.1.3 Determine the heat content or gross calorific value for a sample using the procedures of section 5.5 of appendix F to this part to determine the heat input rate for each hour the unit combusted gaseous fuel. Calculate heat input using the appropriate GCV from sections 2.3.1.4.1 through 2.3.1.4.3 of this appendix.

2.3.1.4 Calculate the hourly SO_2 mass emission rate, in lb/hr, using Equation D–4 of this appendix. Multiply the hourly metered volumetric flow rate of gas combusted (in 100 scfh) by the appropriate sulfur content from sections 2.3.1.4.1 through 2.3.1.4.2 of this appendix.

2.3.1.4.1 For gaseous fuels received in shipments or lots, use one of the following values: (1) the highest sulfur content and GCV from all shipments in the previous calendar year or (2) the maximum sulfur content and maximum GCV values established by agreement with the fuel supplier through a contract. Continue to use this assumed value until and unless the actual sampled sulfur content or gross calorific value of a delivery exceeds the previously reported assumed value.

If the actual sampled sulfur content or gross calorific value of a gas sample is greater than the assumed value for that parameter, then use the actual sampled value for sulfur content or gross calorific value of gas to calculate SO_2 mass emission rate or heat input rate as the new assumed sulfur content or gross calorific value. Continue to use this sampled value to calculate SO_2 mass emission rate or heat input rate until: (1) it is superseded by a new, higher value from a gas sample; (2) a new contract with a higher maximum sulfur content or gross calorific value is adopted, in which case the new contract value becomes the new assumed value; or (3) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.3.1.4.2 For gaseous fuels other than pipeline natural gas that are not received in shipments or lots that are transmitted by pipeline and sampled daily, use the highest sulfur content and GCV from the previous 30 daily gas samples. When continuous gas sampling (at least hourly) is required, use the actual measured hourly average sulfur content for each hour that the gaseous fuel is combusted.

2.3.1.4.3 For pipeline natural gas, use the highest sulfur content in the previous 30 daily gas samples, and the GCV from: (1) one or more samples taken during the most recent month when the unit burned gas for at least 48 hours; (2) the highest GCV from all samples in the previous calendar year; or (3) the maximum GCV values established by agreement with the fuel supplier through a contract. Continue to use this assumed value unless and until the actual sampled sulfur content or gross calorific value of a delivery exceeds the previously reported assumed value.

If the actual sampled sulfur content or gross calorific value of a gas sample is greater than the assumed value for that parameter, use the actual sampled value for sulfur content or gross calorific value of gas to calculate SO_2 mass emission rate or heat input rate as the new assumed sulfur content or gross calorific value. Continue to use this sampled value to calculate SO_2 mass emission rate or heat input rate until: (1) it is superseded by a new, higher value from a gas sample; (2) a new contract with a higher maximum sulfur content or gross calorific value is adopted, in which case the new contract value becomes the new assumed value; or (3) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.3.2 If the fuel is pipeline natural gas, as defined in § 72.2 of this chapter, calculate SO_2 emissions under this section using a default SO_2 emission rate of 0.0006 lb/mmBtu.

2.3.2.1 Use the default SO_2 emission rate of 0.0006 lb/mmBtu and the hourly heat input rate from pipeline natural gas in mmBtu/hr, as determined using the procedures in section 5.5 of appendix F to this part. Calculate SO_2 mass emission rate using Equation D–5 of this appendix. Determine the heat content or gross calorific value for at least one sample each month that the gaseous fuel is combusted using the procedures in section 5.5 of appendix F to this part.

2.3.2.2 The procedures in this section 2.3.2 may also be used for a gaseous fuel other than pipeline natural gas if the Administrator approves a petition under § 75.66(i) in which the designated representative demonstrates that the gaseous fuel combusted at the unit has an SO_2 emission rate no greater than 0.0006 lb/mmBtu. To demonstrate this, the petition shall include at least 720 hours of fuel sampling data, indicating the total sulfur content and GCV of the fuel for each hour. Each hourly value of the total sulfur content in the gas or blend (in gr/100 scf) shall be converted to a ''fuel sulfur-to-heating value ratio,'' by dividing the total sulfur content by the gross calorific value of the fuel (in Btu/100 scf) and then multiplying by a conversion factor of 10^6 Btu/mmBtu. The mean value of the fuel sulfur-to-heating value ratios shall then be calculated. If the mean value of the ratios does not exceed 2.0 grains of sulfur per mmBtu, then the default SO_2 emission rate of 0.0006 lb/mmBtu may be used to account for SO_2 mass emissions under this part, whenever the gaseous fuel is combusted.

2.3.3 For all types of gaseous fuels, the owner or operator shall provide, in the monitoring plan for the unit, historical fuel sampling information on the sulfur content of the gaseous fuel sufficient to demonstrate that use of this appendix is applicable because the gas has a total sulfur content of 20.0 grain/100 scf or less. Provide this information with the initial monitoring plan for the unit and following any significant changes in gas contract or source of supply. However, for units combusting pipeline natural gas that have gas flowmeters certified prior to the effective date of this rule, this information may be retained on site in a form suitable for inspection, rather than submitted as an update to the monitoring plan. In addition, provide the following specific information in the monitoring plan required under § 75.53, depending on the type of gaseous fuel:

2.3.3.1 For pipeline natural gas, provide information demonstrating that the definition of pipeline natural gas in § 72.2 of this chapter has been met. 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 pipeline transportation contract; (2) a certification of the gas vendor, based on routine vendor sampling and analysis; or (3) at least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently.

2.3.3.2 For gaseous fuel other than pipeline natural gas for which a petition has been submitted and approved under section 2.3.2.2 of this appendix, provide the information required to be included in the petition pursuant to section 2.3.2.2.

2.3.3.3 For liquefied petroleum gas and other gaseous fuels provided in batches or lots having uniform sulfur content, provide either contractual information from the fuel supplier or provide historical information on each lot of liquefied petroleum gas from at least one year.

2.3.3.4 For any other gaseous fuel or blend, including gas produced by a variable process (e.g., digester gas or landfill gas), provide data on the fuel sulfur content, as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content of the gas or blend (in gr/100 scf). The data shall be obtained with a gas chromatograph, and, for gaseous fuel produced by a variable process, the data shall be representative of all process operating conditions. The data shall be reduced to hourly averages and shall be used to determine whether daily sampling of the sulfur content of the gas or blend is sufficient or whether sampling, at least hourly, with a gas chromatograph is required. Specifically, daily gas sampling shall be sufficient, provided that either: (1) the mean value of the total sulfur content of the gas or blend is ≤7 grains per 100 scf; or (2) the standard deviation of the hourly average values from the mean does not exceed 5 grains per 100 scf. If the gas or blend does not meet requirement (1) or (2), then sampling, at least hourly, of the fuel with a gas chromatograph (GCH) and hourly reporting of the hourly average sulfur content of the fuel is required. If sampling, at least hourly, from a gas chromatograph is required, the owner or operator shall develop and implement a program to quality assure the data from the GCH, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.4 * * *

2.4.1 Missing Data for Oil and Gas Samples

When oil sulfur content, density, or gross calorific value 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, 2.3.1, 2.3.1.1, 2.3.1.2, or 2.3.1.3 of this appendix, then substitute the maximum potential sulfur content, density, or gross calorific value of that fuel from Table D–7 of this appendix.

TABLE D–7.—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	0.30 gr/100 scf for pipeline natural gas, or 20.0 gr/100 scf for other gaseous fuel.
Gas GCV/Heat Content	1100 Btu/scf for pipeline natural gas, or 2100 Btu/scf for 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: (1) the maximum fuel flow rate the unit is capable of combusting or (2) 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 * * *

65. Section 3 of appendix D to part 75 is amended by:

a. Revising sections 3, 3.1, 3.2, 3.2.1, 3.2.3, 3.2.4, and 3.3;

b. Redesignating section 3.4 as section 3.5 and revising the introductory text; and

c. Adding a new section 3.4, to read as follows:

3. Calculations

Use the calculation procedures in section 3.1 of this appendix to calculate SO_2 mass emission rate. 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. Calculate hourly SO_2 mass emission rate from gaseous fuel using the procedures in section 3.3 of this appendix. Calculate hourly heat input rate for oil and for gaseous fuel using the equations in section 5.5 of appendix F to this part. Calculate total SO_2 mass emissions and heat input as provided under section 3.4 of this appendix.

3.1 SO_2 Mass Emission Rate Calculation for Oil

3.1.1 Use the following equation to calculate SO_2 mass emissions per hour (lb/hr):

$$M_{SO_2} = 2.0 \times M_{oil} \times \frac{\%S_{oil}}{100.0}$$

(Eq. D–2)

where:

MSO_2 = Hourly mass emission rate of SO_2 emitted from combustion of oil, lb/hr.

M_{oil} = Mass rate of oil consumed per hr, 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 Oil Using Volumetric Flow Rate

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 2.2.5 of this appendix, use the following equation to calculate the rate of the mass of oil consumed (in lb/hr):

$$M_{oil}=V_{oil}\times D_{oil}$$

(Eq. D–3)

Where:

M_{oil} = Mass rate of oil consumed per hr, lb/hr.

V_{oil} = Volume rate of oil consumed per hr, measured in scf, gal, barrels, or m^3.

D_{oil} = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m^3.

3.2.4 Calculate the hourly heat input rate to the unit from oil (mmBtu/hr) by multiplying the heat content of the daily oil sample by the hourly oil mass rate.

3.3 SO_2 Mass Emissions Rate Calculation for Gaseous Fuels

3.3.1 Use the following equation to calculate the SO_2 emission rate using the gas sampling and analysis procedures in section 2.3.1 of this appendix:

$$M_{(SO_2)g} = \left(\frac{2.0}{7000}\right) \times Q_g \times S_g$$

(Eq. D–4)

Where:

$M_{(SO2)g}$ = Hourly mass rate of SO_2 emitted due to combustion of gaseous fuel, lb/hr.

Q_g = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.

S_g = 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 the following equation to calculate the SO_2 emission rate using the

0.0006 lb/mmBtu emission rate in section 2.3.2 of this appendix:

$M_{(SO2)g} = ER \times HI_g$

(Eq. D–5)

Where:

$M_{(SO2)g}$ = Hourly mass rate of SO_2 emissions from combustion of pipeline natural gas, lb/hr.

ER = SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas.

Hi_g = Hourly heat input rate of pipeline natural gas, calculated using procedures in appendix F to this part, in mmBtu/hr.

3.3.3 Record the SO_2 mass emission rate for each hour when the unit combusts gaseous fuel.

3.4 Conversion of Rates to Totals and Summation of Quarterly and Cumulative Values

3.4.1 SO_2 Mass Emissions Conversions and Summations.

For a unit or for a common pipe, calculate total quarterly SO_2 mass emissions (using Equation D–6) and total cumulative SO_2 mass emissions (using Equation D–7). First convert hourly SO_2 mass emission rates for each fuel to total hourly SO_2 mass emissions, by multiplying the hourly rates by the fuel usage time. Second, sum the total hourly SO_2 mass emissions from all fuels for the quarter. Third, convert the quarterly SO_2 mass emission total to tons. Finally, for cumulative emissions, sum the quarterly SO_2 mass emission totals, in tons, for each quarter in the year to date.

$$SO_{2_q} = \frac{1}{2000} \sum_{\text{first fuel}}^{\text{last fuel}} \sum_{\text{hour}=1}^{n} \sum_{\text{first system}}^{\text{last system}} SO_{2i\ \text{fuel system}} t_i$$

(Eq. D–6)

Where:

SO_{2q} = Total SO_2 mass emissions for the quarter, tons.

$SO_{2i\ \text{fuel system}}$ = SO_2 mass emission rate for a given fuel for a particular fuel flow system, lb/hr.

t_i = Fuel usage time for the fuel and system, hour or fraction of an hour.

$$SO_{2_c} = \sum_{q=1}^{\text{the current quarter}} SO_{2_q}$$

(Eq. D–7)

Where:

SO_{2c} = Total SO_2 mass emissions for the year to date, tons.

SO_{2q} = Total SO_2 mass emissions for the quarter, tons.

3.4.2 Heat Input Conversions and Summations

Calculate total quarterly (using Equation D–8) and total cumulative (using Equation D–9) heat input for a unit or common pipe with fuel flow systems.

$$HI_q = \sum_{\text{first fuel}}^{\text{last fuel}} \sum_{\text{hour}=1}^{n} \sum_{\text{first system}}^{\text{last system}} HI_{i\ \text{fuel system}} t_i$$

(Eq. D–8)

Where:

HI_q = Total heat input for the quarter, mmBtu.

$HI_{i\ \text{fuel system}}$ = Heat input rate during fuel usage for a given fuel for a particular fuel flow system, using Equation F–19 or F–20, mmBtu/hr.

t_i = Fuel usage time for the fuel and system, hour or fraction of an hour.

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q$$

(Eq. D–9)

Where:

HI_c=Total heat input for the year to date, mmBtu.

HI_q=Total heat input for the quarter, mmBtu.

3.5 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 3.4 of this appendix.

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APPENDIX E TO PART 75—OPTIONAL NO_X EMISSIONS ESTIMATION PROTOCOL FOR GAS-FIRED PEAKING UNITS AND OIL-FIRED PEAKING UNITS

* * * * *

66. Section 2 of appendix E to part 75 is amended by revising sections 2.5.4 and 2.5.5 to read as follows:

2. Procedure

* * * * *

2.5 Missing Data Procedures

* * * * *

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.

67. Section 3 of Appendix E to part 75 is 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:

$H_T = HI_{fuel\ 1} t_1 + HI_{fuel\ 2} t_2 + HI_{fuel\ 3} t_3 + ... + HI_{lastfuel} t_{last}$

(Eq. E–1)

Where:

H_T=Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.
$HI_{fuel\ 1,2,3,...last}$=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.
$t_{1,2,3....last}$=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 January 1, 2000 or to the nearest 0.001 lb/mmBtu for tests performed on and after January 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.

$$E_h = \frac{\sum_{f=1}^{\text{all fuels}} \left(E_f \times HI_f t_f\right)}{H_T}$$

(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.

68. Section 2 of appendix F to part 75 is revised 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):

$$E_h = KC_hQ_h$$

(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):

$$E_h = KC_{hp}Q_{hs}\frac{\left(100 - \%H_2O\right)}{100}$$

(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:

$$E_q = \frac{\sum_{h=i}^{n} E_h t_h}{2000}$$

(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.

$$E_a = \sum_{q=1}^{4} E_q$$

(Eq. F–4)

Where:

E_a = Annual total SO_2 mass emissions, tons.
E_q = Quarterly total 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.

69. Section 3 of appendix F to part 75 is 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:

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n}$$

(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.

$$E_a = \sum_{i=1}^{m} \frac{E_i}{m}$$

(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 January 1, 2000 and to the nearest 0.001 lb/mmBtu on and after January 1, 2000.

70. Section 4 of appendix F to part 75 is amended by revising sections 4.1, 4.2, 4.3, and 4.4.1 to read as follows:

4. Procedures for CO_2 Mass Emissions

* * * * *

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):

$$E_h = KC_hQ_h$$

(Eq. F–11)

Where:

E_h = Hourly CO_2 mass emission rate during unit operation, tons/hr.

K = 5.7 X 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):

$$E_{CO_2q} = \sum_{h=1}^{H_R} E_h t_h$$

(Eq. F–12)

Where:

$E_{(CO2)q}$ = 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.

* * * * *

4.4 * * *

4.4.1 Use appropriate F and F_c factors from section 3.3.5 of this appendix in the following equation to determine hourly average CO_2 concentration of flue gases (in percent by volume):

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9}$$

(Eq. F–14a)

Where:

CO_{2d} = Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.

F, F_c = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.

20.9 = Percentage of O_2 in ambient air.

O_{2d} = Hourly average O2 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.

or

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \%H_2O}{100} \right) - O_{2w} \right]$$

(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.

* * * * *

71. Section 5 of appendix F to part 75 is amended by revising sections 5, 5.1, 5.2, 5.5, 5.5.1, and 5.5.2 and by adding new sections 5.3, 5.6, and 5.7 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 below. 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 below 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:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100}$$

(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:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100 F_c} \right] \left(\frac{\%CO_2 d}{100} \right)$$

(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 above 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:

$$HI = Q_w \frac{1}{F} \frac{\left[(20.9/100)(100 - \%H_2O) - \%O_2 w \right]}{20.9}$$

(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 above 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:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100\ F} \right] \left[\frac{(20.9 - \%O_{2d})}{20.9} \right]$$

(Eq. F–18)

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.
Qw = Hourly average volumetric flow during unit operation, wet basis, scfh.
F = Dry basis F-factor, listed above 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:

$$HI_q = \sum_{hour=1}^{n} HI_i t_i$$

(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:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q$$

(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 When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

$$HI_o = M_o \frac{GCV_o}{10^6}$$

(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. 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:

$$HI_g = \frac{\left(Q_g \times GCV_g\right)}{10^6}$$

(Eq. F–20)

Where:

HI_g=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 GCH, 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.

* * * * *

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:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{MW_i t_i}{\sum_{i=1}^{n} MW_i t_i}\right]$$

(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:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i t_i}{\sum_{i=1}^{n} SF_i t_i}\right]$$

(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:

$$HI_{Unit} = \frac{\sum_{s=1}^{n} HI_s t_s}{t_{Unit}}$$

(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).

72. Section 8 of appendix F to part 75 is added 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 to account for hourly NO_X mass emissions, and the procedures in section 8.2 to account for quarterly, seasonal, and annual NO_X mass emissions if the provisions of subpart H of this part are adopted as requirements under such a program.

8.1 Use the following procedures to calculate hourly NO_X mass emissions in lbs for the hour.

8.1.1 If both NO_X emission rate and heat input are monitored at the same unit or stack level (e.g, the NO_X emission rate value and heat input value both represent all of the units exhausting to the common stack), use the following equation:

$$M_{NO_{X_h}} = E_h HI_h t_h$$

(Eq. F–23)

Where:

$M_{NOx(h)}$=NO_X mass emissions in lbs for the hour.

E_h=Hourly average NO_X emission rate for hour h, lb/mmBtu.

H_{ih}=Hourly average heat input rate for hour h, mmBtu/hr.

t_h=Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_X emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.1.2 If NO_X emission rate is measured at a common stack and heat input is measured at the unit level, sum the hourly heat inputs at the unit level according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^{p} HI_u t_u}{t_{CS}}$$

(Eq. F–24)

Where:

HI_{CS}=Hourly average heat input rate for hour h for the units at the common stack, mmBtu/hr.

t_{CS}=Common stack operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)(e.g., total time when any of the units which exhaust through the common stack are operating).

HI_u=Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u=Unit operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). Use the hourly heat input rate at the common stack level and the hourly average NO_X emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_X mass emissions at the common stack.

8.1.3 If a unit has multiple ducts and NO_X emission rate is only measured at one duct, use the NO_X emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_X mass emissions.

8.1.4 If a unit has multiple ducts and NO_X emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_X mass emissions.

8.2 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_X mass emissions, in tons:

$$M_{(NO_X)_{\text{time period}}} = \frac{\sum_{h=1}^{p} M_{(NO_X)_h}}{2000}$$

(Eq. F–25)

Where:

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

$M_{(NOX)h}$=NO_X mass emissions in lbs for the hour.

p=The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

8.3 Specific provisions for monitoring NO_X mass emissions from common stacks. The owner or operator of a unit utilizing a common stack may account for NO_X mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a state or federal NO_X mass reduction program:

8.3.1 The owner or operator may determine both NO_X emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_X mass emissions.

8.3.2 The owner or operator may determine the NO_X emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_X mass emissions.

APPENDIX G TO PART 75—DETERMINATION OF CO_2 EMISSIONS

* * * * *

73. Section 2 of appendix G to part 75 is amended by revising the term ''Wc'' that follows Equation G–1 to read as follows:

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 for oil and diesel fuel, and one fuel sample for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, or for each monthly sample of pipeline natural gas. 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.

* * * * *

74. Appendix G to part 75 is amended by adding a new section 5 and Table G–1 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 1/1/2000

Prior to January 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 January 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 below.

5.1.2 [Reserved]

5.2 Missing Carbon Content Data on and After 1/1/2000

Prior to January 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 January 1, 2000, use the procedures of this section to substitute for missing carbon content data.

5.2.1 Missing Weekly Samples

If carbon content data are missing for weekly coal samples or composite oil samples from continuous sampling, substitute the highest carbon content from the previous four carbon samples available. If no previous carbon content data are available, use the default carbon content from Table G–1, below.

5.2.2 Manual Sample From Storage Tank

If carbon content data are missing for manual oil or diesel fuel samples taken from the storage tank after transfer of a new delivery of fuel, substitute the highest carbon content from all samples in the previous calendar year. If no previous carbon content data are available from the previous calendar year, use the default carbon content from Table G–1, below.

5.2.3 As-Delivered Sample

If carbon content data are missing for as-delivered samples of oil, diesel fuel, or gaseous fuel delivered in lots, substitute the highest carbon content from all deliveries of that fuel in the previous calendar year. If no previous carbon content data are available for that fuel from the previous calendar year, use the default carbon content from Table G–1, below.

5.2.4 Sample of Gaseous Fuel Supplied by Pipeline

If carbon content data are missing for a gaseous fuel that is supplied by a pipeline and sampled on either a monthly or a daily basis for sulfur and gross calorific value, substitute the highest carbon content available for that fuel from the previous calendar year. If no previous carbon content data are available for that fuel from the previous calendar year, use the default carbon content from Table G–1, below.

TABLE G–1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Sampling technique/frequency	Missing data substitution procedure
Oil and coal carbon content	All oil and coal samples, prior to January 1, 2000	Most recent, previous carbon content value available for that grade of oil.
	Weekly coal sample or Flow proportional/weekly composite oil sample (beginning no later than January 1, 2000).	Highest carbon in previous 4 weekly samples.
	In storage tank (after addition of fuel to tank) (beginning no later than January 1, 2000).	Maximum carbon content from all samples in previous calendar year.
	As delivered (in delivery truck or barge) (beginning no later than January 1, 2000).	Maximum carbon content from all deliveries in previous calendar year.
Gas carbon content	All gaseous fuel samples, prior to January 1, 2000	Most recent, previous carbon content value available for that type of gaseous fuel.
	Gaseous fuel in lots—as-delivered sampling (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
	Gaseous fuel delivered by pipeline that is sampled for sulfur content—daily sampling (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
	Pipeline natural gas that is not sampled for sulfur content—monthly sampling for GCV and carbon only (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
Default coal carbon content	All	Anthracite: 90.0 percent. Bituminous: 85.0 percent. Subbituminous/Lignite: 75.0 percent.
Default oil carbon content	All	90.0 percent.

TABLE G–1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA—Continued

Parameter	Sampling technique/frequency	Missing data substitution procedure
Default gas carbon content ..	All	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

75. Appendix H to part 75 is removed and reserved.

76. Appendix I to part 75 is added as follows:

Appendix I To Part 75—Optional F-Factor/Fuel Flow Method

1. Applicability

1.1 This procedure may be used in lieu of continuous flow monitors for the purpose of determining volumetric flow from gas-fired units, as defined in § 72.2 of this chapter, or oil-fired units, as defined in § 72.2 of this chapter, provided that the units burn only pipeline natural gas, natural gas, and/or fuel oil. These procedures use fuel flow measurement, fuel sampling data, CO_2 (or O_2) CEMS data, and F-factors to determine the flow rate of the stack gas. These procedures may only be used during those hours when only one type of fuel is combusted.

1.2 Apply to the Administrator, in a certification application, for approval to use this method in lieu of a continuous flow monitor, no later than the deadlines for the certification of continuous emission monitoring systems specified in §§ 75.20 and 75.63.

2. Procedure

2.1 Initial Certification and Recertification Testing

Either of the following procedures may be used to perform initial certification and recertification testing of the appendix I excepted flow monitoring system:

2.1.1 Component-by-Component Certification Testing

Test both the fuel flowmeter component and the CO_2 (or O_2) monitor component separately, following the procedures of this part. Determine BAF_{System} and BAF_{CO2} or BAF_{O2}, using the procedures in section 3.7 of this appendix.

2.1.1.1 Certification of the Fuel Flowmeter

Test the fuel flowmeter according to the procedures and performance specifications in section 2.1.5 of appendix D to this part.

2.1.1.2 Certification of the CO_2 (or O_2) Monitor

Test the CO_2 or O_2 monitor according to the procedures and performance specifications in appendix A to this part. Notwithstanding the requirements of appendix A to this part, calculate the BAF of the CO_2 or O_2 monitor according to section 3.7 of this appendix.

2.1.2 System Certification Testing

Test the entire appendix I flow monitoring system to meet the relative accuracy requirements for flow, as found in section 3.3.4 of appendix A to this part, using the applicable procedures in sections 6.5 through 6.5.2.2 of appendix A to this part. Use the fuel sampling data for density and carbon content to calculate the hourly volumetric flow rate according to section 2.3 of this appendix. Perform the bias test and, if necessary, calculate a bias adjustment factor for the appendix I flow monitoring system using the procedures in section 7.6 of appendix A to this part. Also perform the 7-day calibration error test, cycle time test, and linearity check on the CO_2-or O_2-diluent monitor.

2.2 On-Going Quality Assurance Testing

2.2.1 Daily Assessments

The CO_2 or O_2 monitor shall meet the daily assessment requirements in section 2.1 of appendix B to this part.

2.2.2 Quarterly Assessments

The CO_2 or O_2 monitor shall meet the quarterly assessment requirements in section 2.2 of appendix B to this part.

2.2.3 Semiannual or Annual Assessments

2.2.3.1 Component-by-Component Assessments

Test both the fuel flowmeter and the CO_2 (or O_2) monitor separately. Determine BAF_{System} and BAF_{CO2} or BAF_{O2} using the procedures in section 3.7 of this appendix.

2.2.3.1.1 Assessment of the Fuel Flowmeter

The fuel flowmeter shall meet the periodic quality assurance requirements in section 2.1.6 of appendix D to this part. The fuel flowmeter shall meet the flowmeter accuracy specification in section 2.1.5 of appendix D to this part.

2.2.3.1.2 Relative Accuracy Assessment of the CO_2 (or O_2) Monitor

Test the CO_2 or O_2 monitor for relative accuracy according to the applicable procedures in sections 6.5 through 6.5.2.2 of appendix A to this part. Determine the relative accuracy test frequency (i.e., semiannual or annual) using section 2.3.1 and figure 2 in appendix B to this part. Perform the bias test and calculate any bias adjustment factor, as specified in section 3.7.1 of this appendix for the CO_2 monitor or as specified in section 3.7.2 of this appendix for the O_2 monitor.

2.2.3.2 System Relative Accuracy Assessment

Test the entire appendix I flow monitoring system to meet the relative accuracy requirements for flow, as found in section 3.3.4 of appendix A to this part, using the procedures in section 6.5.2 of appendix A to this part. Use Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to obtain the reference method flow rate value for each run. Use the appropriate equation selected from Eq. I–1 through Eq. I–9 to calculate the Appendix I flow rate value for each RATA run. Base the fuel sampling on section 2.3 of this appendix. Determine the schedule for future relative accuracy tests using the provisions of section 2.3.1 and figure 2 of appendix B to this part for a flow monitoring system. Perform the bias test and, if necessary, calculate a bias adjustment factor for the appendix I flow monitoring system using the procedures in section 7.6 of appendix A to this part.

2.3 Fuel Sampling and Analysis

2.3.1 Carbon Content of Oil

Determine carbon content of the oil by using the following procedures. Collect at least one sample per each shipment for oil and diesel fuel. Determine the carbon content of the fuel sampling using one of the following methods: 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.

2.3.2 Density of Oil

Determine the density of oil using the procedures in section 2.2 of appendix D to this part.

2.3.3 Gross Calorific Value of Natural Gas

Determine gross calorific value of natural gas by using the procedures in section 5.5.2 of appendix F to this part.

3. Calculations

3.1 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use a CO_2 Monitor and a Volumetric Oil Flowmeter

$$Q_s = \frac{32.08 \times V \times \rho \times \%C}{\%CO_2}$$

(Eq. I–1)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–10A or I–10B (for component-by-component testing) in section 3.7 of this appendix or by Equation I–11 (for system testing) in section 3.8 of this appendix.

V=Volumetric oil flow rate, gal/hr.

ρ=Oil density, lb/gal.

%C=Percent carbon by weight.

$\%CO_2$=CO_2 concentration, percent by volume.

32.08=Conversion factor, 385 scf CO_2/12 lb C, volume of CO_2 emitted for each pound carbon in oil.

3.2 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use an O_2 Monitor and a Volumetric Oil Flowmeter

3.2.1 If relative accuracy is determined on a system basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times BAF_{system} \times V \times \rho \times \%C \times (20.9)(100)}{\left(20.9 - \%O_{2d}\right) \times \left(100 - \%H_2O\right)}$$

(Eq. I–2)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–11 (for system testing) in section 3.8 of this appendix.

V=Volumetric oil flow rate, gal/hr.

ρ=Oil density, lb/gal.

%C=Percent carbon by weight.

$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_2O$=Percent moisture in the flue gas.

207.6379=Conversion factor, 385 scf CO_2/12 lb C×9190 dscf O_2/1420 scf CO_2, volume of O_2 emitted for each pound carbon in oil.

3.2.2 If relative accuracy is determined on a component by component basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times 1.12 \times V \times \rho \times \%C \times (20.9)(100)}{\left[20.9 - \left(BAF_{O2} \times \%O_{2d}\right)\right] \times \left(100 - \%H_2O\right)}$$

(Eq. I–3)

Where:

Q_s Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{O2}=Bias adjustment factor for the O_2 monitor, as determined by section 3.7.2 of this appendix.

V=Volumetric oil flow rate, gal/hr.

ρ=Oil density, lb/gal.

%C=Percent carbon by weight.

$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_2O$=Percent moisture in the flue gas.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

207.6379=Conversion factor, 385 scf CO_2/12 lb C×9190 dscf O_2/1420 scf CO_2, volume of O_2 emitted for each pound carbon in oil.

3.3 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use a CO_2 Monitor and a Mass Oil Flowmeter

$$Q_s = \frac{32.08 \times BAF_{system} \times M \times \%C}{\%CO_2}$$

(Eq. I–4)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–10A or I–10B (for component by component testing) in section 3.7 of this appendix or by Equation I–11 (for system testing) in section 3.8 of this appendix.

M=Oil mass flow rate, lb/hr.

%C=Percent carbon by weight.

$\%CO_2$=CO_2 concentration, percent by volume.

32.08=Conversion factor, 385 scf CO_2/12 lb C, volume of CO_2 emitted for each pound carbon in oil.

3.4 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use an O_2 Monitor and a Mass Oil Flowmeter

3.4.1 If relative accuracy is determined on a system basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times BAF_{system} \times M \times \%C \times (20.9)(100)}{\left(20.9 - \%O_{2d}\right) \times \left(100 - \%H_2O\right)}$$

(Eq. I–5)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–11 (for system testing) in section 3.8 of this appendix.

M=Oil mass flow rate, lb/hr.

%C=Percent carbon by weight.

$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_2O$=Percent moisture in the flue gas.

207.6379=Conversion factor, 385 scf CO_2/12 lb C×9190 dscf O_2/1420 scf CO_2, volume of O_2 emitted for each pound carbon in oil.

3.4.2 If relative accuracy is determined on a component by component basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times 1.12 \times M \times \%C \times (20.9)(100)}{\left[20.9 - \left(BAF_{O2} \times \%O_{2d}\right)\right] \times \left(100 - \%H_2O\right)}$$

(Eq. I–6)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.
BAF_{O2}=Bias adjustment factor for the O2 monitor, as determined by section 3.7.2 of this appendix.
M=Oil mass flow rate, lb/hr.
%C=Percent carbon by weight.
$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.
$\%H_2O$=Percent moisture in the flue gas.
1.12=Default multiplier used to compensate for systematic error in the demonstration data.
207.6379=Conversion factor, 385 scf CO_2/12 lb C×9190 dscf O_2/1420 scf CO_2, volume of O_2 emitted for each pound carbon in oil.

3.5 Hourly Volumetric Flow during Combustion of Natural Gas Only for Systems that Use a CO_2 Monitor and a Volumetric Gas Flowmeter

$$Q_s = \frac{0.01 \times BAF_{system} \times V \times GCV \times F_c}{\%CO_2}$$

(Eq. I–7)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.
BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–10A or I-10B (for component by component testing) in section 3.7 of this appendix or by Equation I–11 (for system testing) in section 3.8 of this appendix.
V=Volumetric gas flow rate, 100 scfh.
GCV=Gross calorific value of the gaseous fuel, Btu/scf.
F_c=Carbon-based F-factor of 1040 scf CO_2/mmBtu for natural gas, from section 3 of appendix F to this part.
$\%CO_2$=CO_2 concentration, percent by volume.
0.01=Conversion factor, 10^{-6} mmBtu/Btu×10² scf/100 scf×10² (conversion of fraction to percentage).

3.6 Hourly Volumetric Flow during Combustion of Natural Gas Only for Systems that Use an O_2 Monitor and a Volumetric Gas Flowmeter

3.6.1 Determining Flow for Systems that Are Tested on a System Basis

$$Q_s = \frac{0.01 \times BAF_{system} \times V \times GCV \times F_d \times (20.9)(100)}{(20.9 - \%O_{2d}) \times (100 - \%H_2O)}$$

(Eq. I–8)

Where:

Q_2=Volumetric stack flow rate, adjusted for bias, in scfh.
BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–11 (for system testing) in section 3.8 of this appendix.
V=Volumetric gas flow rate, 100 scfh.
GCV=Gross calorific value of the natural gas, Btu/scf.
F_d=Dry basis, O_2-based F-factor for natural gas, 8,710 dscf/mmBtu.
$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.
$\%H_2O$=Percent moisture in the flue gas.
0.01=Conversion factor, 10^{-6} mmBtu/Btu x 10² scf/100 scf×10² (conversion of fraction to percentage).

3.6.2 Determining Flow for Systems that are Tested on a Component-by-Component Basis

$$Q_s = \frac{0.01 \times 1.12 \times V \times GCV \times F_d \times (20.9)(100)}{\left[20.9 - (BAF_{O2} \times \%O_{2d})\right] \times (100 - \%H_2O)}$$

(Eq. I–9)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.
BAF_{O2}=Bias adjustment factor for the O_2 monitor, as determined by section 3.7.2 of this appendix.
V=Volumetric gas flow rate, 100 scfh.
GCV=Gross calorific value of the natural gas, Btu/scf.
F_d=Dry basis, O_2-based F-factor for natural gas, 8,710 dscf/mmBtu.
$\%O2_{2d}$=Dry basis O_2 concentration, percent by volume.
$\%H_d2O$=Percent moisture in the flue gas.
1.12=Default multiplier used to compensate for systematic error in the demonstration data.
0.01=Conversion factor, 10^{-6} mmBtu/Btu x 10² scf/100 scf x 10² (conversion of fraction to percentage).

3.7 Bias Adjustment Factor for a System Tested Component-by-Component

3.7.1 Calculation of the System Bias Adjustment Factor, BAF_{system}, for CO_2 Monitor

Calculate the mean difference of the relative accuracy test data for the CO_2 monitor, d, using Equation A–7 in section 7.3.1 of appendix A to this part. Calculate the confidence coefficient (cc) using Equation A–9 in section 7.3.3 of appendix A to this part. If $\bar{d}$ < -cc, where $\bar{d}$ is defined by Equation A–7, calculate the bias adjustment factor for a system tested component by component, as follows:

$$BAF_{system} = \frac{1.12}{\left(1 + \frac{\bar{d}}{\overline{\overline{CEM}}}\right)}$$

(Eq. I–10A)

If d ≥ -cc, then

BAF_{system}=1.12

(Eq. I–10B)

Where:

BAF_{system}=Overall bias adjustment factor for the appendix I flow monitoring system.
1.12=Default multiplier used to compensate for systematic error in the demonstration data.
$\bar{d}$=Mean difference between the reference method and continuous emission monitoring system (RM_i-CEM_i) as defined in Equation A–7 in section 7.3.1 of appendix A to this part.
$\overline{CEM}$=Mean of the data values provided by the CO_2 monitor during the relative accuracy test audit.

3.7.2 Calculation of the Component Bias Adjustment Factor, BAF_{O2}, for O_2 Monitor

Perform the bias test for the O_2 monitor using the procedures in section 7.6 of appendix A to this part and, if necessary, calculate a bias adjustment factor.

3.8 Bias Adjustment Factor for a System Tested on a System Level

Calculate the bias adjustment factor for a system tested on a system level, as follows:

BAF_{System}=$GAF_{flow\ rate}$

(Eq. I–11)

Where:

BAF_{system}=Overall bias adjustment factor for the appendix I flow monitoring system.
$BAF_{flow\ rate}$=Bias adjustment factor from relative accuracy testing using Reference Method 2 for volumetric flow rate.

4. Missing Data

4.1 The owner or operator shall provide substitute volumetric flow data using the flow missing data procedures in subpart D of this part.

4.2 [Reserved]

5. Recordkeeping and Reporting

Follow the applicable monitoring plan provisions of § 75.53, the applicable general recordkeeping provisions of § 75.57, the specific recordkeeping provisions of § 75.58(g), the certification recordkeeping provisions of § 75.59(d)(1), and the quality assurance test recordkeeping provisions of § 75.59(d)(2). Maintain a quality assurance/quality control plan, as specified in appendix

B to this part. Follow the reporting provisions of §§ 75.60 through 75.67.

77. Appendix J to part 75 is removed and reserved.

[FR Doc. 98–11749 Filed 5–20–98; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 75

[FRL–6007–7]

RIN 2060–AH64

Acid Rain Program: Determinations under EPA Study of Bias Test and Relative Accuracy and Availability Analysis

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed determinations and proposed rulemakings.

SUMMARY: Title IV of the Clean Air Act Amendments of 1990 (the Act) authorizes EPA to establish a program to reduce the adverse effects of acidic deposition. The Act requires electric utilities affected by the Acid Rain Program to install continuous emission monitoring systems (CEMS) to measure emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2). On January 11, 1993, Continuous Emission Monitoring regulations were published. They established procedures and requirements for installing, certifying, operating, and quality assuring CEMS at Acid Rain affected utility units. In response to comments and litigation from representatives of the electric utility industry and environmental advocacy groups, provisions were incorporated in the CEMS regulations requiring EPA to conduct studies, reach determinations, and, if necessary, initiate rulemakings on the appropriateness of retaining or revising three elements in the CEMS regulations: the bias test, relative accuracy test, and the availability trigger conditions of the Missing Data Substitution Procedure. This Notice of Proposed Rulemaking presents EPA's proposed determinations and consequent proposed rule revisions.

DATES: *Comments.* Comments on the proposed determinations and rule revisions must be received on or before July 6, 1998.

Public Hearing. Anyone requiring a public hearing must contact EPA no later than June 1, 1998. If a hearing is held, it will take place June 5, 1998, beginning at 10:00 a.m.

ADDRESSES: *Comments.* All written comment must be identified with the appropriate docket number (Docket No. A–97–56) and must be submitted in duplicate to EPA Air Docket Section (6102), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW, Washington, D.C. 20460.

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

Docket. Docket No. A–97–56, containing supporting information used to develop the proposed determinations and rule revisions is available for public inspection and copying from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section at the above address.

FOR FURTHER INFORMATION CONTACT: Elliot Lieberman at (202) 564 9136, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M St., S.W., Washington, D.C. 20460; or the Acid Rain Hotline at (202) 564 9620. Electronic copies of this notice and technical support documents can be accessed through the Acid Rain Division website at http://www.epa.gov/acidrain.

SUPPLEMENTARY INFORMATION:

I. EPA Studies Under 40 CFR 75.7

A. Background

To ensure a consistent level of precision and accuracy in the emission measurements obtained across the Acid Rain Program, Part 75 of the Acid Rain regulations requires a series of performance tests to be conducted on each CEMS both at initial certification and periodically thereafter. Among the required performance tests is the relative accuracy test audit (RATA) in which a minimum of nine simultaneous measurements are taken from a unit's installed CEMS and an EPA approved reference method. The paired RATA data are then subjected to two statistical tests: The relative accuracy test, which establishes the degree of accuracy of the CEMS relative to the reference method; and the bias test, which uses a t-statistic to determine if the CEMS measurements are consistently lower than the reference method measurements. *See* 40 CFR Part 75, Appendix A and B.

As stated in the preamble of the January 1993 regulations, EPA found that ''both statistical theory and field test results show that the bias test is a sound and effective statistical procedure for detecting consistent measurement error in the long-term operation of a CEMS'' (58 FR 3590, 3627 (1993)). However, at the time of promulgation of the Acid Rain regulations, although utilities had extensive experience with the relative accuracy test, they had virtually no previous experience with the bias test. This unfamiliarity led to several concerns with the bias test. Thus, the January 1993 regulations committed EPA to conduct field studies to determine ''whether there are statistically significant variances'' in the EPA-approved reference methods that utilities use to test the performance of the CEMS installed under the Acid Rain Program and ''whether the bias test should be adjusted to compensate for statistical variances in the reference method'' (58 FR 3628).

In particular, EPA was required to:

1. Investigate whether there are statistically significant variances in the EPA reference methods (Issue #1);

2. Distinguish between the variability in reference monitor readings attributable to measurement error and the variability due to the choice of reference monitor among those certified by the Agency (Issue #2);

3. Investigate possible differences in bias test failure rates by emission levels (Issue #3); and

4. Assess whether any adjustments are necessary to properly determine measurement bias (Issue #4).

The regulations called for the completion of a study addressing these issues by October 31, 1993. In response, EPA conducted two studies. The first was a collaborative field study, involving four independent reference method test teams, at Big Rivers Electric Corporation's Green Generating Station, Unit 2, in Sebree, Kentucky. This location was specifically selected for testing because its relatively low range of SO_2 emission concentrations (from 56 ppm to 231 ppm) would allow EPA to examine bias test failure rates at SO_2 emission levels different from those prevailing in previous field studies and consider an industry concern that