ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 75

[FRL–5650–7]

RIN 2060–AF58

Acid Rain Program; Continuous Emission Monitoring Rule Technical Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Title IV of the Clean Air Act (CAA or the Act), as amended by the Clean Air Act Amendments of 1990, authorizes the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. The Acid Rain Program and the provisions in today's final 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 acidic deposition precursor emissions. 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 a direct final rule to make the implementation of the program simpler. Furthermore, on May 17, 1995 the Agency published an interim final rule and took comment on the provisions in the interim final rule.

In this final rule, EPA is amending certain provisions of the CEM regulations in response to public comments received on the direct final and interim final rules. These amendments will streamline the rule and increase implementation flexibility for the affected industry.

DATES: Effective Date. This final rule shall become effective on December 20, 1996.

Incorporation by Reference. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of December 20, 1996.

ADDRESSES: Docket No. A–94–16, containing supporting information used in developing the final rule, is available for public inspection and copying at the following address: Air and Radiation Docket and Information Center (6102), U.S. Environmental Protection Agency, 401 M Street SW, Washington, DC 20460. The docket is located in Room M–1500, Waterside Mall (ground floor) and may be inspected from 8:30 a.m. to noon, and from 1 to 3 p.m., Monday through Friday. Copies of information in the docket may be obtained by request from the Air Docket by calling (202) 260–7548. A reasonable fee may be charged for copying docket materials.

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) 233–9180.

SUPPLEMENTARY INFORMATION: The EPA is revising the CEM provisions as a final rule because the Agency has already taken comment on the provisions that are being revised. The information in this preamble is organized as follows:

I. Regulated Entities

Entities potentially regulated by this action are fossil fuel-fired utility boilers and turbines that serve a generator which generates electricity for sale. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Electric Utility Boilers and Turbines.

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 that 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.

II. Background and Summary of the Final Rule

Title IV of the Act requires the 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 General Provisions of the Permits Regulation and 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 a notice of interim final rulemaking making further changes to the regulations were published on May 17, 1995 (60 FR 26510 and 60 FR 26560, respectively). There are several provisions in the interim final rule that will expire on January 1, 1997. Therefore, this final rule addresses these provisions that will expire, reaffirms several provisions of the interim final rule that are not changing and revises sections of the interim final rule based on comments. The final rule also modifies a few provisions of the direct final rule on which the Agency received comments.

The issues addressed by this final rule are: (1) Revising the daily assessment procedures set forth in the interim final rule, (2) revising the monitoring methods for units with sulfur dioxide (SO_2) continuous emission monitoring systems (CEMS) during hours when the unit is only burning gaseous fuels, (3) clarifying the procedures for performing cycle time tests (appendix A, section 6.4), (4) revising the reporting of scrubber parameter ranges in the monitoring plan, (5) clarifying the procedures dealing with the use of Reference Method 9 instead of continuous opacity monitoring systems (COMS) on bypass stacks, (6) addressing minor comments on the direct final rule and (7) addressing comments on RATA notifications.

This final rule addresses the following sections. Section 75.6, ''Incorporation by reference,'' is revised to incorporate the American Gas Association (AGA) ''AGA Report Number 7.'' This change is being made in response to comments received on the direct final rule and petitions received and approved by the Agency to use ''AGA Report Number 7.''

Sections 75.11 (e) and (g), ''Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors),'' as established by the interim final rule, expire on January 1, 1997. The provisions in § 75.11(a) were suspended from July 17, 1995 through December 31, 1996. In this final rule, §§ 75.11 (a), (d), and (e) are being revised and § 75.11(g) is being removed based on comments on the interim final rule.

Section 75.16, ''Special provisions for monitoring emissions from common, bypass and multiple stacks for SO_2 emissions and heat input determinations,'' § 75.18, ''Specific provisions for monitoring emissions from common and bypass stacks for opacity,'' and § 75.20, ''Certification and recertification requirements,'' are being revised in response to comments received on the direct final rule.

Section 75.21(f), ''Quality assurance and quality control requirements,'' as established by the interim final rule, expires January 1, 1997. The provisions in § 75.21(a) were suspended from July 17, 1995 through December 31, 1996. In this final rule, § 75.21(a) is revised and § 75.21(f) is deleted based on comments on the interim final rule. Section 75.21(d), ''Notification for periodic relative accuracy test audits,'' is added based on comments received on the direct final rule.

Section 75.30(d), ''General provisions,'' is revised based on comments received on this section from the interim final rule. Section 75.30(e) remains in effect from the interim final rule with no changes.

Section 75.32(a)(4), ''Determination of monitoring data availability for standard missing data procedure,'' as established by the interim final rule, expires January 1, 1997. The provisions in § 75.32(a)(3) were suspended from July 17, 1995 through December 31, 1996. In this final rule, § 75.32(a)(3) is revised and § 75.32(a)(4) is deleted based on comments on the interim final rule.

Sections 75.34 (a), (b), (c), and (d), ''Units with add-on emission controls,'' § 75.53(d), ''Monitoring plan,'' §§ 75.55 (b) and (e), ''General recordkeeping provisions for specific situations,'' §§ 75.56 (a), (c), and (d), ''Certification, quality assurance and quality control record provisions,'' and § 75.66(f), ''Petitions to the Administrator,'' are revised based on comments on the interim final rule. Section 75.61(a)(5), ''Periodic relative accuracy test audits,'' is added based on comments received on the direct final rule. Sections 75.64 and 75.66(e) remain in effect from the interim final rule with no changes.

Sections 6.3.3 and 6.3.4 in appendix A of part 75, ''Pollutant concentration monitor and CO_2 or O_2 monitor 7-day calibration error test'' and ''Flow monitor 7-day calibration error test,'' respectively, as established by the interim final rule, expire January 1, 1997. The provisions in sections 6.3.1 and 6.3.2 of appendix A were suspended from July 17, 1995 through December 31, 1996. In this final rule, sections 6.3.1 and 6.3.2 of appendix A are deleted, section 6.3.3 is revised, and sections 6.3.3 and 6.3.4 of appendix A of the interim final rule are redesignated as sections 6.3.1 and 6.3.2.

Section 6.4.1 of appendix A, ''Cycle time test,'' as established by the interim final rule, expires January 1, 1997. The provisions in section 6.4 of appendix A were suspended from July 17, 1995 through December 31, 1995. In this final rule, section 6.4 of appendix A is revised and section 6.4.1 of appendix A is deleted based on comments on the interim final rule.

Appendix B to part 75 is amended by adding section 1.6, ''Parametric monitoring for units with add-on emission controls''. This addition is based on comments received on the interim final rule.

Section 2.1.7 of appendix B, ''Daily assessments,'' as established by the interim final rule, expires January 1, 1997. The provisions in section 2.1 of appendix B were suspended from July 17, 1995 through December 31, 1995. In this final rule, sections 2.1 and 2.1.1 of appendix B are revised, sections 2.1.1.1 and 2.1.1.2 are added, section 2.1.2 is deleted, section 2.1.3 is redesignated as section 2.1.2, the new section 2.1.2 is revised, sections 2.1.4 and 2.1.5 are redesignated as sections 2.1.3 and 2.1.4, respectively; sections 2.1.5, 2.1.5.1 and 2.1.5.2 are added, and section 2.1.7 of appendix B is deleted based on comments on the interim final rule.

Appendix D of part 75, ''Optional SO_2 emissions data protocol for gas-fired and oil-fired units,'' is amended by revising section 2.1.5.1 based on comments on the direct final rule.

Section 7 of appendix F of part 75, ''Procedures for SO_2 mass emissions at units with SO_2 continuous emission monitoring systems during the combustion of gaseous fuel,'' is revised based on comments received on the interim final rule.

III. Rationale

A. Revising the Daily Assessment Procedures Set Forth in the Interim Final Rule

This section addresses several issues related to the frequency of performing daily assessments (i.e., daily calibration error tests and flow interference checks) for the purpose of quality assuring data from CEMS and flow monitoring systems. Based on comments received on the May 17, 1995 interim final rule, section 2 of appendix B is revised in today's rule with respect to four main issues. The first issue deals with unit operation during daily calibration error tests of gas and flow monitoring systems and is discussed in section A.1 below. The second issue deals with unit operation during interference checks of flow monitoring systems and is addressed in section A.2 below. The third issue deals with quality assurance of data with respect to daily calibration error tests and is described in section A.3 below. The final issue deals with quality assurance of data with respect to daily flow interference checks and is discussed in section A.4 below. In addition, the structural and regulatory changes that have been made to section 2 of appendix B are described in detail in section A.5 below.

1. Unit Operation During Daily Calibration Error Tests

Background: This issue is related to the daily calibration error tests required for CEMS and flow monitoring systems under section 2 of appendix B of part 75. The following provisions of the January 11, 1993 final rule required the affected unit to be operating during daily calibration error tests: section 2.1.1 of appendix B and sections 6.1 and 6.3.2 of appendix A. The May 17, 1995 interim final rule reaffirmed, both in the preamble at 60 FR 26564–65 and in section 2.1.7 of appendix B, the requirement to perform daily calibration error tests of gas monitors and flow monitors while the unit is operating.

Calibration error tests are required to be performed while the unit is operating because readings from the CEMS and flow monitoring systems are affected by temperature and pressure conditions

(See Docket A–96–16, Item II–D–39, Log of telephone conversation between Jon Konings, WEPCo, and M. Sheppard, EPA, on EPA's calibration error test policy, April 13, 1994.) Section 6.3.1 of appendix A of the January 11, 1993 final rule and section 6.3.3 of appendix A of the May 17, 1995 interim final rule both affirm that the calibration error test of a CEMS is to be a test of the entire monitoring system, not just a test of the analyzer. At least a portion of the sampling interface of a CEMS is directly exposed to stack conditions. Since there is a significant variation in stack temperature and pressure, depending on whether or not the unit is in operation, CEMS readings can vary accordingly. Therefore, to ensure accurate CEMS measurements, calibration error tests should be performed under the same or similar conditions as when emission data are collected by the CEMS.

Issue: During the public comment period for the interim final rule, some commenters raised concerns about the requirement to perform daily calibration error tests while the unit is operating. (See Docket A–94–16, Items V–D–04, V–D–07, V–D–09, V–D–11, V–D–13, V–D–14, and V–D–15.) Commenters mentioned that monitoring technologies exist which are capable of minimizing the effects of pressure and temperature regardless of unit operation. Therefore, for some monitoring systems, calibration error test results should not be affected by the operation or non-operation of the unit. The commenters requested that, to assist them in meeting the part 75 quality assurance requirements, and to minimize the loss of concentration and flow data, EPA allow daily calibration error tests to be performed while the unit is not operating. Some commenters provided data showing a history of successful off-line calibrations. Other commenters mentioned specific monitoring technologies capable of performing valid off-line calibration error tests (e.g., fully extractive systems with measurement on a dry basis, and dilution extractive systems with heated probes and pressure compensation).

J.A. Jahnke, PhD, an authority on CEM technology, identified the following technologies which, if used properly, could minimize the effects of temperature and pressure: (1) fully extractive dry systems in which the calibration gas is not injected prior to an external probe filter, (2) ex-situ dilution systems with an accurate pressure compensation algorithm, and (3) in-stack dilution systems with a heated probe maintained at constant temperature and with accurate pressure compensation. (See Docket A–94–16, Item II–C–7, ''Further comments on Continuous Emission Monitoring (CEM) System Calibration Error Checks for Unit Off-line/On-line Conditions,'' J.A. Jahnke, PhD, Source Technology Associates.)

Response: The EPA agrees with the commenters that some types of CEMS are capable of minimizing the effects of temperature and pressure upon the CEMS measurements, and are therefore capable of performing a valid calibration error test while the unit is not operating. However, there are also CEMS and flow monitoring systems in use which clearly do not have this capability. For example, in-situ electro-optical systems can experience alignment problems when used on a hot stack after being calibrated on a cold stack. Also, a dilution probe system without a probe heater and without temperature and pressure compensation can underestimate pollutant concentrations in hot flue gas after being calibrated off-line. In addition, the effectiveness of some monitoring system technologies varies with the specific installation or with the ambient conditions. For instance, temperature and pressure compensation algorithms are often site-specific and may be difficult to apply properly; or a dilution extractive system with a probe heater may only be able to perform valid off-line calibrations during the warmer spring and summer months. Therefore, in some instances, using the results of an off-line calibration error test to validate data from a monitoring system could result in an underestimation of emissions. (See Docket A–94–16, Item II–C–7, ''Further comments on Continuous Emission Monitoring (CEM) System Calibration Error Checks for Unit Off-line/On-line Conditions,'' J.A. Jahnke, PhD, Source Technology Associates; Item II–C–8, EPRI, 1994; and Item II–D–94, Phone log between Margaret Sheppard and City of Hamilton.)

The EPA agrees with the conclusions of Dr. Jahnke and several of the commenters, that in some instances, off-line calibration error tests may be appropriate to provide affected units more flexibility in meeting the quality assurance testing requirements of appendix B of part 75. The EPA also agrees with the commenters who stated that more flexibility would be especially helpful to small peaking units that operate infrequently and routinely alternate between operation and non-operation. Therefore, section 2.1.1.2 of appendix B of today's rule allows limited use of off-line calibration error tests to validate CEM data.

Section 2.1.1.1 of appendix B of today's rule retains the requirement that on-line calibration error tests must be done for all monitoring systems. However, to give owners or operators greater flexibility in complying with the quality assurance requirements of part 75, an exception has been provided in section 2.1.1.2 of appendix B, which allows some off-line calibrations to be done. The Agency has decided not to allow the unqualified use of off-line calibration error tests for the following reasons: (a) accurate monitoring system temperature corrections may not be possible for units that undergo large swings in temperature, e.g., cycling (peaking) units; (b) for dilution systems (even with heaters), inaccurate readings may occur if the dilution air flow does not reach equilibrium with stack temperature; and (c) temperature correction equations may be site-specific and therefore, may not be applied correctly. (See Docket A–94–16, Item II–C–8, ''Pressure and Temperature Effects in Dilution Extractive Continuous Emission Monitoring Systems,'' EPRI TR–104700, December 1994.)

In developing the final off-line calibration error test provision, EPA considered two implementation approaches: (1) a technology-specific approach that would allow certain monitoring technologies to perform off-line calibration error tests to validate data; and (2) a performance-based approach, in which any monitoring system that passed a performance test would be allowed to use occasional off-line calibration error tests to validate data.

Although some monitoring technologies may be capable of performing valid off-line calibration error tests, EPA has several concerns regarding a technology-specific approach. First, the effectiveness of many monitoring system technologies is site-specific (e.g., temperature and pressure compensation algorithms, heated dilution probes). Therefore, a global endorsement of a particular technology is not prudent. Second, a technology-specific approach may not cover all possible candidate monitoring systems, and thus may not be equitable to all monitoring system vendors. Finally, because monitoring technologies change over time, frequent rule revisions would be needed to ensure continued fairness to the CEMS vendors. For these reasons, EPA decided against a technology-specific approach.

The EPA concluded that a performance-based approach would better ensure a ''level playing field'' for all monitoring technologies by establishing a demonstration which could be attempted by any candidate monitoring system capable of compensating for the effects of temperature and pressure. Occasional off-line calibration error tests for data validation would then be allowed for any monitoring system that successfully performed the demonstration. Frequent rule revisions would not be required with a performance-based approach because it can accommodate changing technology.

For these reasons, today's rule allows occasional off-line calibration error tests to be used for data validation, for any monitoring system that passes a one-time performance test designed to demonstrate the validity of an off-line calibration error test. The performance test, referred to as the ''Off-line Calibration Demonstration,'' is found at section 2.1.1.2 of appendix B of today's rule. The demonstration requires a candidate monitoring system to pass a calibration error test while the unit is not operating and then, within 26 clock hours, to pass a calibration error test while the unit is operating. Both of these calibration error tests must meet the performance specification in section 3.1 of appendix A. The EPA selected the 26 clock hours separation time between the calibration error tests to be consistent with the usual length of time of prospective data validation from a calibration error test. Routine calibration adjustments are allowed following the off-line calibration error test; these adjustments must be toward the true calibration gas or reference signal value.

The performance demonstration is not intended to establish unqualified equivalence between off-line and on-line calibration error tests, but rather to screen out monitoring systems that are clearly incapable of performing a valid calibration error test while the unit is not operating. The EPA remains concerned that even if a monitoring system has passed the off-line calibration demonstration, it may be miscalibrated based on an off-line calibration and subsequently it may underestimate emissions. In that instance, the CEMS would most likely fail the next on-line calibration. The EPA considered incorporating a proposal by one commenter to address this concern. The proposal would have required retrospective invalidation of data whenever an on-line calibration error test is failed following an off-line calibration. However, EPA did not incorporate this suggestion because of the complexity of programming, for both utilities and the EPA, involved in implementing retrospective invalidation. Instead, EPA may propose additional limitations on the use of off-line calibration error tests in a future rulemaking to ensure that off-line calibrations are only performed where appropriate. This will give the public opportunity to comment on the additional provisions.

Whenever possible, calibration error tests should be scheduled and performed while the unit is operating. If a unit operates infrequently (i.e., a peaking unit or a cycling unit) consideration should be given to scheduling automatic calibration at a time the unit is most likely to be operating. The provisions in today's rule allowing some off-line calibration error tests are meant to provide additional flexibility in special circumstances and thus minimize the need to use missing data routines. Off-line calibration error tests are not intended to replace on-line calibration error tests. Therefore, section 2.1.1.2 of appendix B of today's rule requires that an on-line calibration error test be performed within 26 unit operating hours of any off-line calibration error test used to validate data. If, for a particular CEMS or flow monitoring system, an on-line calibration error test is not performed within 26 unit operating hours of an off-line calibration error test used to validate data, section 2.1.3.1 of appendix B requires missing data to be substituted beginning in the 27th unit operating hour. To allow time for these new missing data requirements to be incorporated in data acquisition and handling system (DAHS) software, the new missing data requirements become effective on January 1, 1999. Prior to January 1. 1999, the owner or operator may elect to comply with the new missing data requirements.

Although today's rule allows off-line daily calibration error tests in specific circumstances, the Agency is retaining the requirement in sections 6.3.1 and 6.3.2 of appendix A for the initial 7-day calibration error test of pollutant and diluent monitoring systems and flow monitoring systems to be performed while the unit is operating. The EPA has decided to retain the requirement to perform the 7-day calibration error test on-line for two reasons. First, the 7-day calibration error test must only be performed for the initial certification of a monitoring system and occasionally for recertification; the test is not part of the periodic quality assurance requirements in appendix B. Second, for the reasons stated previously, the Agency considers on-line calibration error tests to have a higher probability of indicating the true accuracy of the monitoring system.

2. Unit Operation During Daily Flow Monitor Interference Checks

Background: The January 11, 1993 final rule did not specifically address the issue of unit operation during daily interference checks of flow monitors. However, section 2.1.7 of appendix B of the May 17, 1995 interim final rule required all daily assessments, including flow monitoring system interference checks, to be performed while the unit is operating. The requirement to perform daily assessments while the unit is operating was promulgated so that the test would be performed under the same conditions as when emissions measurements are recorded.

Issue: No comments were received on the issue of unit operation during daily flow interference checks.

Response: Because no comments were received on this issue, the provision requiring flow monitoring system interference checks to be performed on-line is adopted as final. Section 2.1.7 of appendix B has been removed from today's rule. The requirement to perform on-line flow interference checks has been moved to section 2.1.3.

3. Quality Assurance of Data Following Daily Calibration Error Tests

Background: Section 2.1 of appendix B of the January 11, 1993 final rule (incorporated unchanged into the May 17, 1995 interim final rule) required daily assessments of monitoring system accuracy, such as calibration error tests and flow interference checks, to be performed during each day in which a unit combusts any fuel (i.e. each operating day) or, for a monitoring system on a bypass stack or duct, during each day that emissions pass through the bypass stack or duct. In addition, section 2.1.1 of appendix B of the January 11, 1993 final rule stated that pollutant concentration and carbon dioxide (CO_2) or oxygen (O_2) monitors were required to conduct calibration error checks, to the extent practicable, approximately 24 hours apart.

In March 1995, EPA published a policy in Update #5 of the ''Acid Rain Program Policy Manual''. (See Docket A–94–16, Item II–D–95) which interprets sections 2.1 and 2.1.1 of appendix B. The policy (which is outlined in the answer to Question 10.13) states that ''a passed calibration test prospectively validates data for that monitoring system beginning with the hour in which the test is passed for 26 clock hours''. This policy allows a 2-hour grace period beyond a 24-hour ''day'' as an interpretation of the provision in section 2.1.1 of appendix B to perform the tests ‘‘approximately 24 hours apart’’. The policy includes a ‘‘grace’’ period of up to 8 clock hours for data validation during start-up events. The start-up grace period was included as part of the interpretation of the daily calibration provisions in response to utility concerns that if a unit is shut down or in an unstable start-up condition when a daily calibration error test is due, it might be impossible to perform a valid daily calibration for several hours, until stable temperature and pressure conditions are achieved.

The preamble to the May 17, 1995 interim final rule discussed quality assurance of data following daily calibration error tests at 60 FR 26564. Section 2.1.7 of appendix B was added in the May 17, 1995 interim final rule to address the situation in which a unit discontinues operation or the use of the bypass stack or duct is discontinued prior to the performance of a daily calibration error test; the new section added flexibility for that situation so that data from the monitoring system are considered quality-assured prospectively for up to 24 consecutive clock hours following a successful daily test. However, the May 17, 1995 interim final rule did not provide for an 8-hour start-up grace period.

Issue: During the public comment period for the interim final rule, EPA received comments on the added section 2.1.7 of appendix B. One commenter declared that section 2.1.7 of appendix B may require units, particularly peaking units, to operate unnecessarily and at higher load levels than they would otherwise operate. The commenter stated that this will result in unnecessary emissions, contrary to the intent of the law and proposed a solution to provide a grace period that excuses calibrations for start-up situations. (See Docket A–94–16, Item V–D–11). Another commenter expressed concern that section 2.1.7 of appendix B provided a validation period of only 24 hours and did not allow for an 8-hour grace period. The commenter urged EPA to incorporate the language from Question 10.13 in the ‘‘Acid Rain Program Policy Manual’’ into the final rule provisions. (See Docket A–94–16, Item V–D–17). Similarly, other commenters expressed support for the more flexible approach provided in the manual as it allows for quality assurance of data under more real-life operating scenarios. (See Docket A–94–16, Item V–D–07). The commenters requested that the rule be revised to be consistent with the data validation policy in Question 10.13 of the manual. (See Docket A–94–16, Items V–D–13, V–D–15.)

Response: The EPA agrees with the commenters that requiring a unit to operate and produce emissions solely for the purpose of performing a test on time does not meet the intent of the regulation. In addition, EPA agrees that a prospective data validation period of 26 clock hours and a start-up grace period of 8 clock hours provides additional flexibility to units, particularly peaking and cycling units, in order to meet the requirements to perform daily assessments. Therefore, today’s rule revises section 2 of appendix B as described in the summary in section A.5 below to incorporate the 26-hour validation period and 8-hour start-up grace period for daily assessments. For monitoring systems that have passed the Off-line Calibration Demonstration, the 8-hour grace period does not apply if an off-line calibration error test has been performed since the last on-line calibration error test.

4. Quality Assurance of Data Following Daily Flow Interference Checks

Background: Section 2.1 of appendix B of the January 11, 1993 final rule (incorporated unchanged into the May 17, 1995 interim final rule) addressed the requirements for daily assessments of monitoring system accuracy, such as daily calibration error tests for gas and flow monitoring systems and daily interference checks for flow monitoring systems.

Section 2.1.7 of appendix B, entitled ‘‘Daily Assessments,’’ was added in the May 17, 1995 interim final rule to address the situation where a unit discontinues operation or where the use of the bypass stack or duct is discontinued prior to the performance of a daily assessment. However, the rule language mentions only the daily calibration error test, not the flow monitor interference check.

In November 1995, EPA published an answer in Update #7 of the ‘‘Acid Rain Program Policy Manual.’’ (See Docket A–94–16, Item II–D–97) which interprets sections 2.1 and 2.1.7 of appendix B. The answer to Question 10.18 states that the data validation policy for daily calibration error tests also applies to daily interference checks for flow monitors.

Issue: A commenter requested that the interim final rule be revised so that the prospective data validation policy for daily calibration error tests, proposed in section 2.1.7 of appendix B and Question 10.13 in the ‘‘Acid Rain Program Policy Manual,’’ be extended to include daily flow monitor interference checks as well. (See Docket A–94–16, Item V–D–18).

Response: The EPA agrees with the commenter that the prospective data validation policy for daily flow interference checks should be consistent with the provision for daily calibration error tests. In fact, the original intent was for section 2.1.7 of appendix B of the interim final rule to apply to all daily assessments, both calibration error tests and flow interference checks. Therefore, today’s rule revises section 2 of appendix B, as described in the summary in section A.5 below, to incorporate the 26-hour validation period and 8-hour start-up grace period for all daily assessments, including flow monitor interference checks.

5. Summary of Structure and Regulatory Changes to Section 2 of Appendix B

In order to incorporate revisions to section 2 of appendix B, some of the subsections are structured differently in today’s rule than in the May 17, 1995 interim final rule and the January 11, 1993 final rule. First, section 2.1.2, which addresses daily calibration error tests for flow monitoring systems, is removed, and section 2.1.1 is revised to address daily calibration error tests for both gas concentration and flow monitoring systems. Secondly, sections 2.1, 2.1.1, and 2.1.3 of appendix B of the interim final rule are revised by removing the requirement to perform daily assessments every unit operating day. Instead, the new sections 2.1.3 and 2.1.3.1 of today’s rule describe the 26-hour prospective data validation from a passed daily assessment and the invalidation of data resulting when a daily assessment is not performed. Also, the new section 2.1.3.2 in today’s rule describes the 8-hour start-up grace period for daily assessments. Third, section 2.1.3 of the interim final rule is redesignated as section 2.1.2 in today’s rule; the new section 2.1.2 is also revised to add the requirement to perform flow interference checks on-line (previously in section 2.1.7) and to remove the requirement to perform flow interference checks every unit operating day. Instead, the provisions for quality assuring data with respect to daily flow interference checks are addressed with the requirements for all daily assessments in the new sections 2.1.5, 2.1.5.1, and 2.1.5.2 of today’s rule. Fourth, sections 2.1.4 and 2.1.5 are redesignated as sections 2.1.3 and 2.1.4, respectively. Finally, section 2.1.7 of appendix B of the interim final rule is removed. The provisions for unit operation during tests and prospective validation following tests which were addressed in section 2.1.7 are now addressed in sections 2.1.1.1, 2.1.1.2, 2.1.2, 2.1.5, 2.1.5.1, and 2.1.5.2. Section

2.1.1.1 addresses the basic requirement to perform daily calibration error tests on-line; section 2.1.1.2 addresses the exception that allows some daily calibration error tests to be performed off-line.

B. Revising the Monitoring Methods for Units With SO_2 CEMS During Hours When the Unit is Only Burning Gaseous Fuels

1. Determination of SO_2 Mass Emissions During Combustion of Gaseous Fuel, for Units With SO_2 CEMS

Background: All of the coal-fired units, many of the oil-fired units, and some of the gas-fired units subject to part 75 requirements currently use an SO_2 CEMS and a flow monitoring system to account for their SO_2 mass emissions. By definition, affected gas-fired units with SO_2 CEMS must derive at least 90 percent of their heat input from the combustion of gaseous fuel. (See definition of ''gas-fired'' in 40 CFR 72.2.) Generally, the fuel is pipeline natural gas. Many of the coal and oil-fired units with SO_2 CEMS derive their heat input exclusively from coal or oil; however, a significant number of the coal and oil-fired units with SO_2 CEMS also combust natural gas (or other gaseous fuel with a sulfur content no greater than natural gas), either as backup fuel or solely during unit startup. Natural gas has a very low sulfur content and will produce extremely low SO_2 concentrations when combusted alone. Typically, SO_2 concentrations from the combustion of natural gas will range from about 0 to 5 parts per million (ppm) for ''sweetened'' pipeline natural gas to about 20 to 30 ppm for ''sour'' natural gas.

It is difficult for most SO_2 monitors to accurately measure the low SO_2 concentrations associated with the combustion of natural gas. It is also difficult to quality-assure SO_2 monitoring data at such low concentrations. Protocol 1 calibration gases at these low concentrations are either not available or are very expensive, and relative accuracy test audits (RATAs) of the SO_2 monitor are of questionable value because gas-fired SO_2 concentrations are generally at, near or below the limit of detectability of both the CEMS and the reference method.

Issue: Sections 75.11(a) and 75.11(d) of the January 11, 1993 final rule required owners or operators of coal-fired units and allowed owners or operators of oil-fired and gas-fired units to account for SO_2 emissions using an SO_2 monitoring system. No conditions were placed upon the use of the SO_2 monitor, either for coal-fired, oil-fired or gas-fired units. No distinction was made between SO_2 monitoring during the combustion of gaseous fuel and SO_2 monitoring during hours in which higher-sulfur fuel such as coal or oil is combusted. In the preamble to the May 17, 1995 interim final rule, however, EPA expressed concern about the difficulty of obtaining accurate, quality-assured SO_2 emission data from an SO_2 CEMS when natural gas is combusted. (See 60 FR 26561.) The Agency decided that it was inappropriate to use an SO_2 CEMS during hours in which only natural gas (or gaseous fuel with a sulfur content no greater than natural gas) is combusted in an affected unit. Therefore, under § 75.11(e) of the interim final rule, beginning on January 1, 1997, owners or operators of affected units with SO_2 CEMS would no longer be permitted to use an SO_2 CEMS to account for SO_2 emissions during gas-fired hours. Instead, SO_2 emissions during gas-fired hours were to be determined in one of two ways: (1) by certifying and quality-assuring an excepted monitoring system in accordance with appendix D of part 75; or (2) for pipeline natural gas combustion, by using the heat input derived from flow monitor and diluent monitor measurements, in conjunction with the default emission rate of 0.0006 pounds per million British thermal unit (lb/mmBtu) for pipeline natural gas, from EPA publication AP–42. (See ''Compilation of Air Pollutant Emission Factors: Stationary Point and Area Sources,'' volume I, fourth edition, Office of Air Quality Planning and Standards, September 1985.) Either of these two compliance options requires additional programming of the DAHS.

The May 17, 1995 interim final rule also amended the quality assurance provisions of § 75.21 to be consistent with the two proposed SO_2 compliance options for gas-fired hours. Owners or operators were exempted from daily calibration assessments of the SO_2 monitoring system on any day when only gas was burned in the affected unit, and from quarterly linearity tests of the SO_2 monitoring system in quarters when only gas was fired. Also, ''gas-only'' quarters were not to be counted toward determination of the next RATA deadline for the SO_2 monitoring system, but a RATA of the monitoring system was still required at least once every 2 years.

Several commenters objected to the provisions in § 75.11(e) of the interim final rule, arguing that the requirements were too complex and costly to implement because of the additional DAHS programming and did not provide any environmental benefit. (See Docket A–94–16, Items V–D–01, V–D–02, V–D–07, V–D–09, V–D–13 and V–D–16.) A number of commenters also indicated that the requirements were especially burdensome to coal and oil-fired units in which natural gas is burned only during unit startup. (See Docket A–94–16, Items V–D–01, V–D–02, V–D–07, V–D–13, V–D–15 and V–D–18).

Several commenters submitted data to demonstrate the ''de minimis'' nature of gas-fired SO_2 emissions during unit startups. (See Docket A–94–16, Items V–D–01, V–D–08 and V–D–16.) One commenter provided calculations to show that the SO_2 concentration during gas-fired startup events is, typically, 2 ppm or less when pipeline natural gas is burned. (See Docket A–94–16, Item V–D–08). A second commenter's data indicate that historically only about 0.20 tons per year (tpy) of SO_2 have been emitted from his four affected coal-fired units during gas-fired startup events. (See Docket A–94–16, Item V–D–16). A third commenter used the default emission factor for SO_2 to estimate that about 0.005 tpy of SO_2 are emitted from his affected facility during gas-fired startups. The third commenter also provided a cost estimate of approximately $10,000 for that same facility to reprogram the DAHS to comply with the requirements of the interim final rule. (See Docket A–94–16, Item V–D–01).

Several commenters recommended that, in addition to the two SO_2 compliance options for gas-fired hours presented in the May 17, 1995 interim final rule, EPA should, in the final rule, reinstate the use of an SO_2 monitoring system and a flow monitoring system as a third compliance option. (See Docket A–94–16, Items V–D–07, V–D–09, V–D–16 and V–D–17.) One commenter suggested that EPA could place certain restrictions and conditions on the use of the SO_2 monitor during gas-fired hours, rather than excluding its use. (See Docket A–94–16, Item V–D–17). Another commenter stated that for gas-firing, EPA could require the use of a calibration gas with a concentration of 0.0 percent of span for the daily calibration error tests, to verify that the monitoring system can accurately read SO_2 concentrations at or near zero ppm. (See Docket A–94–16, Item V–D–09). Another commenter, attempting to address EPA's concern about the ability of an SO_2 monitor to accurately read the low SO_2 concentrations associated with natural gas firing, submitted 328 hours of data recorded by his SO_2 monitoring system during gas-fired hours. The data appear to substantiate that an SO_2 monitor can detect variations in SO_2 concentration, even at very low ppm levels; most of the measured concentrations were between 1 and 5 ppm, with occasional readings above 10 ppm. The commenter also compared the SO_2 emissions measured by the CEMS in the 328-hour period to the emissions that would have been reported if the default emission factor for pipeline natural gas plus the CEMS-based heat input had been used. The emissions measured by the SO_2 monitor were found to be significantly higher than the emissions predicted by the default emission factor. (See Docket A–94–16, Item V–D–16). Another commenter recommended that EPA consider specifying some type of ''default'' SO_2 concentration, perhaps based on the maximum sulfur content of pipeline natural gas, to be used when reporting data from an SO_2 CEMS during gas-fired hours. (See Docket A–94–16, Item IV–D–13.) For example, whenever the CEMS recorded an hourly average below the default value, the default value would be reported for that hour. Finally, one commenter requested that EPA add a qualifying statement to the exemption from the requirement to perform daily calibration error tests and linearity tests of SO_2 monitors during ''gas only'' days and ''gas only'' calendar quarters. The qualifying statement would affirm that SO_2 monitors which ''* * * meet the applicable performance specification for a daily calibration error test or quarterly linearity check while firing natural gas only, do not require a subsequent re-test should the unit change from firing only gaseous fuel to a nongaseous fuel within the respective daily or quarterly timeframe * * *'' In other words, the owner or operator may, at his discretion, continue to perform calibration error tests and linearity tests when natural gas is combusted, to keep the SO_2 monitor ready for use. The results of such tests would be considered valid. The commenter recommended that this statement be added to the rule to address two unanticipated situations that might ''trigger'' the SO_2 monitor quality assurance requirements: (1) when gas is combusted for most of a day, but peak electrical demand necessitates the co-firing of oil and gas; and (2) when natural gas is the primary fuel burned during a quarter, but emergency electrical demand necessitates that some oil be burned. (See Docket A–94–16, Item V–D–28).

Response: The Agency has reconsidered the provisions of the May 17, 1995 interim final rule in view of the comments received and has decided to allow three SO_2 compliance options, rather than two, for units with SO_2 CEMS during hours in which only natural gas (or gaseous fuel with a sulfur content no greater than natural gas) is burned. These options are set forth in § 75.11(e) of today's rule.

The first two compliance options for hours in which the unit combusts only natural gas or gaseous fuel with a sulfur content no greater than natural gas are located at §§ 75.11 (e)(1) and (e)(2). These provisions have changed very little from § 75.11(e) of the interim final rule. The owner or operator may account for SO_2 emissions, in lieu of using the SO_2 CEMS, by either: (1) For pipeline natural gas, determining the heat input using flow and diluent monitors, and then using the default SO_2 emission rate factor of 0.0006 lb/mmBtu to calculate SO_2 mass emissions, in accordance with Equation F–23 in section 7 of appendix F of part 75; or (2) certifying an excepted monitoring system in accordance with appendix D to part 75 and using the fuel sampling and analysis procedures in section 2.3.1 of appendix D. Section 75.11(e)(2) of today's rule clarifies that when the appendix D fuel sampling procedures are used, the unit heat input reported under § 75.54(b)(5) must be based upon hourly averages from the installed flow and diluent monitors, rather than basing it on the fuel flow rate and gross calorific value as specified in section 3 of appendix D and section 5.5 of appendix F. This ensures consistency in the reported heat input data for all hours of unit operation; irrespective of the type of fuel combusted in the unit, the reported heat input values will be based on CEMS data.

The third compliance option, located at § 75.11(e)(3), allows the owner or operator to use the SO_2 monitoring system and a flow monitoring system to determine SO_2 mass emissions. However, the use of the SO_2 monitoring system is subject to several conditions and restrictions: (a) a calibration gas with a concentration of 0.0 percent of span must be used for daily calibration error tests of the CEMS; (b) 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; (c) any hourly average of less than 2.0 ppm recorded by the SO_2 monitor (including zero and negative averages) must be reported as a default value of 2.0 ppm; and (d) if a unit combusts only natural gas (or gaseous fuel with a sulfur content no greater than natural gas) and never combusts any other type of fuel, the SO_2 monitor span must be set to a value not exceeding 200 ppm. Note that conditions (a) and (b) are optional for units that combust natural gas only during unit startup. Compliance with conditions (a) through (d) is required by January 1, 1999. Prior to January 1, 1999, owners or operators may either continue to use the SO_2 CEMS without the additional restrictions or may opt to comply voluntarily with conditions (a) through (d). The January 1, 1999 compliance deadline allows owners or operators sufficient time to incorporate the new requirements into their quality assurance programs and to program the 2.0 ppm default SO_2 concentration into their DAHS.

The requirement to use a 0.0 percent calibration gas for daily calibrations and to adjust the response to 0.0 ppm maximizes the chance of obtaining meaningful SO_2 readings at the low concentrations associated with gas-firing. However, despite this extra quality assurance provision, it is likely (particularly when pipeline natural gas is fired) that the CEMS will give some hourly average SO_2 concentrations of zero ppm and may give an occasional negative hourly average, if the monitor readings drift. Therefore, today's rule requires a 2.0 ppm ''default'' concentration value to be reported whenever hourly averages from the CEMS fall below 2 ppm. The 2.0 ppm value is consistent with the average gas-fired SO_2 concentration of 1 to 2 ppm during unit startup, as estimated by one of the commenters, using the default emission rate of 0.0006 lb/mmBtu for pipeline natural gas. (See Docket A–94–16, Item V–D–08). Use of the 2.0 ppm default SO_2 concentration value minimizes the chance of underestimating gas-fired SO_2 emissions and ensures that a negative or zero SO_2 hourly average will not be reported for any hour in which fuel is combusted in the unit.

For units that sometimes fire gas and at other times burn higher-sulfur fuel, § 75.11(e)(3)(iv) of today's rule specifies that dual-range capability is not required for the SO_2 monitoring system; rather, the SO_2 span and range associated with the higher-sulfur fuel also may be used during gas-fired hours. However, for units that burn only natural gas (or gaseous fuel with a sulfur content no greater than natural gas) and do not combust any other fuel, § 75.11(e)(3)(iv) requires that the owner or operator set the span of the SO_2 monitor to a value not exceeding 200 ppm. This span requirement supersedes the provisions in section 2.1.1.1 of appendix A, which would, in this case, require the SO_2 monitor span to be set unrealistically low (e.g., to a value of 5 ppm or less for pipeline natural gas).

As explained in the preamble to the interim final rule, EPA has little or no confidence in the results of RATAs for SO_2 monitors when natural gas is burned in an affected unit. (See 60 FR 26561.) First, the low SO_2 concentrations associated with natural gas combustion (typically 0.5 to 5.0 ppm for pipeline natural gas) are either at, near or below the sensitivity limit of the analytical method, both for the installed SO_2 monitor and for the reference test method (Method 6C in appendix A to 40 CFR part 60). Second, passing an SO_2 RATA when gas is combusted does not necessarily demonstrate that the monitor is accurate. The criterion in section 3.3.1 of appendix A to part 75 for passing the SO_2 RATA (when emission levels are below 250 ppm) is that the average CEMS and average reference method values must agree to within 15.0 ppm. To illustrate, suppose that the average reference method value for a gas-fired RATA of an SO_2 monitor is 10.0 ppm and the average CEMS value is 0.0 ppm. The RATA would be considered to be ''passed'', according to the 15.0 ppm criterion. However, since the CEMS readings averaged 0.0 ppm, the monitor could actually have been malfunctioning or completely inoperative during the RATA test period and still have passed the RATA.

In view of these considerations, § 75.21(a)(5) of today's rule specifies that for units with installed SO_2 monitoring systems, SO_2 RATAs are not to be done when natural gas (or gaseous fuel with a sulfur content no greater than natural gas) is fired; rather, SO_2 RATAs are to be conducted only when higher-sulfur fuels (e.g., oil or coal) are combusted. In keeping with this requirement, § 75.21(a)(6) of today's rule exempts from the SO_2 RATA requirements of part 75 any unit that burns only natural gas (or fuel(s) with a sulfur content no greater than natural gas), and does not burn any other fuel. For such units, only daily calibrations and quarterly linearity tests of the SO_2 monitor, which ensure that the monitor is operational by checking its response to different concentrations of calibration gas, are required. Section 75.21(a)(7) of today's rule specifies that for a unit that sometimes burns natural gas as a primary or backup fuel and at other times burns higher-sulfur fuel as primary or backup fuel, any calendar quarter in which the unit combusts only natural gas (or fuel with a sulfur content equivalent to natural gas) is to be excluded in determining the deadline for the next RATA of the SO_2 monitoring system. This provision of § 75.21(a)(7) is not substantively different from the corresponding provision in § 75.21(f) of the interim final rule; however, as revised, § 75.21(a)(7) extends the benefit of reduced RATA frequency requirements to include the combustion of other types of fuels (whether gaseous and non-gaseous) with a sulfur content no greater than that of natural gas. Finally, § 75.21(a)(7) specifies that if, as a result of extending the RATA deadline of an SO_2 monitor by excluding quarters in which only natural gas (or equivalent) is combusted, eight calendar quarters elapse after a RATA without a subsequent RATA of the SO_2 monitor having been performed, a RATA is then required in the next calendar quarter in which a fuel with a higher sulfur content than natural gas is combusted in the unit. This differs slightly from the provision in § 75.21(f) of the interim final rule, which, in similar circumstances, required an SO_2 RATA at least once every 2 calendar years. These less burdensome RATA requirements for SO_2 monitors in §§ 75.21(a)(5) through (a)(7) will ensure that owners or operators do not have to burn higher sulfur fuels merely to perform quality assurance testing of the CEMS. The Agency believes that the less stringent RATA requirements will also encourage owners and operators to burn more low-sulfur fuels in their affected units, thus resulting in a net environmental benefit while ensuring continued high quality of emissions data.

If, for a particular unit with an SO_2 CEMS, the owner or operator selects one of the other two SO_2 compliance options for gas-fired hours, in lieu of using the SO_2 monitoring system (i.e., either using appendix D fuel flow meter and fuel sampling procedures or using the default emission factor for pipeline natural gas and Equation F–23 in appendix F), § 75.21(a)(4) of today's rule specifies that no daily calibration error tests of the SO_2 monitoring system are required on ''gas-only'' operating days and no quarterly linearity tests are required in ''gas-only'' operating quarters. While these tests are not required, they are allowed and will be considered valid tests for other requirements of this rule. These quality assurance requirements are waived on days and in quarters when only gas is combusted in the unit, because when the appendix D compliance option or the Equation F–23 compliance option is used, hourly averages from the SO_2 CEMS are not included in the historical CEMS data stream, either for emission reporting, missing data substitutions, or monitor availability calculations. Therefore, the hourly averages from the SO_2 monitor do not require quality assurance on ''gas-only'' days or in ''gas-only'' quarters. These requirements are essentially identical to the corresponding provisions in § 75.21(f) of the interim final rule. The Agency notes, however, that although the daily and quarterly assessments of the SO_2 CEMS are not required in these instances, § 75.21(a)(4) of today's rule allows the tests to continue to be done at the discretion of the owner or operator. If the tests are passed, they are considered to be valid tests of the CEMS. If a test is failed, the CEMS is considered out-of-control until a subsequent test of the same type has been passed. This provision addresses the commenter's concern about the unpredictability of the fuel type(s) that are used during periods of peak electrical demand.

2. SO_2 Concentration Missing Data During Gas Combustion

Background: For an affected unit that sometimes combusts natural gas (or gaseous fuel with a sulfur content no higher than natural gas) and sometimes burns higher sulfur fuel, such as coal or oil, the SO_2 emissions during gas-fired hours are several orders of magnitude smaller than during hours in which coal or oil is combusted. When such a unit uses an SO_2 monitor to account for its SO_2 emissions, then, for each clock hour in which the monitor fails to provide quality-assured SO_2 concentration data, a substitute data value for SO_2 concentration must be reported to EPA, in accordance with the standard missing data procedures of § 75.33. The method required for calculating the substitute data under § 75.33 depends on several factors, such as the overall monitor availability and the duration of the monitor outage. In many cases, the substitute data value, which is reported for each clock hour of the missing data period, is the arithmetic average of the SO_2 readings before and after the missing data period. In other cases, the substitute data value may be either the 90th (or 95th) percentile value from the last 720 quality-assured monitor operating hours or simply the maximum value recorded in the last 720 quality-assured monitor operating hours.

Provided that the sulfur content of the fuel burned in an affected unit remains relatively constant, the standard missing data procedures will generally provide representative substitute data. However, when a unit burns two or more fuels whose sulfur contents differ greatly (e.g., coal and natural gas), using the standard missing data procedures can sometimes cause significant underestimation, and at other times, significant overestimation of the SO_2 emissions during missing data periods. This is most likely to occur when an SO_2 missing data period either coincides with or occurs around the time of a fuel-switch.

Issues: In the May 17, 1995 interim final rule, EPA revised the standard SO_2 missing data procedures and the SO_2 data availability calculation procedures, to address the issue of units that have SO_2 monitors and sometimes burn natural gas and at other times combust higher-sulfur fuels. Under § 75.11(e) of the interim final rule, beginning on January 1, 1997, owners or operators would no longer be permitted to use an SO_2 CEMS to account for SO_2 mass emissions during hours in which only natural gas (or gaseous fuel with a sulfur content no greater than natural gas) is burned in an affected unit. Therefore, § 75.30(d)(3) specified that the historical CEM data used to derive the SO_2 substitute data values for the standard missing data procedures would consist only of SO_2 concentrations measured by the CEMS during the combustion of higher-sulfur fuels such as coal or oil. Also, § 75.32(a)(4) specified that the percent SO_2 data availability would be calculated only from the hours in which the higher-sulfur fuels were burned. Section 75.21(f) specified that during natural gas-fired hours, the owner or operator would neither be required to operate nor to quality-assure data from the SO_2 CEMS. Rather, during all gas-fired hours, § 75.11(e) specified that SO_2 emissions would be accounted for in one of two ways: (1) By using an excepted monitoring system, in accordance with the requirements of appendix D to part 75; or (2) for pipeline natural gas combustion, by determining the heat input from a flow monitor and diluent monitor and then using the default SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas to calculate the SO_2 mass emission rate, in accordance with Equation F–23 in appendix F. Sections 75.30 (d)(1) and (d)(2) of the interim final rule specified that missing data for option (1) would be filled in using the missing data procedures in appendix D to part 75; for option (2), the procedures in § 75.36 for missing heat input data would be followed.

Several commenters objected to these provisions of the interim final rule, stating that EPA should not prohibit the use of an SO_2 monitor during natural gas-fired hours, but should allow the CEMS to be used as a third compliance option. (See Docket A–94–16, Items V–D–07, V–D–09, V–D–16 and V–D–17.) Two other commenters stated that use of the standard SO_2 missing data procedures and SO_2 data availability calculation procedures should be allowed, without modification, particularly for units that burn natural gas only during unit startup. (See Docket A–94–16, Items V–D–07 and V–D–15.)

Response: As discussed above, for hours in which only natural gas (or gaseous fuel with a sulfur content no greater than natural gas) is combusted, EPA has decided to revise § 75.11(e) to allow units that have SO_2 monitoring systems and sometimes burn natural gas and at other times burn higher-sulfur fuels to use the SO_2 CEMS (subject to certain conditions and restrictions) as a third compliance option, in addition to the two compliance options presented in the interim final rule.

Today's rule, at § 75.30(d)(4), allows an owner or operator who, pursuant to § 75.11(e)(3), selects the SO_2 monitoring system as the compliance option for gas-fired hours to use both the standard SO_2 missing data procedures and the SO_2 data availability calculation procedures, without modification. This is conditioned on the owner or operator keeping records on-site, suitable for inspection, indicating the type of fuel burned during each SO_2 missing data period and the number of hours during the missing data period that each type of fuel was burned. This recordkeeping requirement, located at § 75.55(e)(2) of today's rule, does not apply if natural gas (or gaseous fuel with a sulfur content no greater than natural gas) is the only type of fuel burned in the unit, or if such fuel is burned only during unit startup.

For several reasons, the Agency believes that allowing units which combust both high and low-sulfur fuels to use the standard missing data procedures will probably not, over time, result in any significant underestimation of SO_2 emissions. First, if a unit maintains high SO_2 data availability (90 to 95 percent), then only a few percent of the SO_2 readings in the data stream will be substitute data values. Second, many missing data periods will not occur at or near the time of a fuel switch, and for those missing data periods, the substitute data values will be representative of the fuel burned. Third, over long periods of time, it is likely that, statistically, the effects of occasionally underestimating and overestimating SO_2 substitute data values will tend to balance out. Nevertheless, to ensure that these things are true, the recordkeeping requirement in § 75.55(e)(2) has been added. This will allow EPA, State, and local government auditors to assess, over time, the appropriateness of the SO_2 substitute data values that are used to fill in missing data periods for units that burn both high and low-sulfur fuels, particularly when fuel-switching occurs. Based on this assessment, EPA may revisit this issue in a future rulemaking, if necessary.

Regarding the calculation of percent SO_2 data availability, § 75.11(e)(3)(iii) of today's rule specifies that when an SO_2 monitor is used to account for SO_2 emissions during gas-fired hours, all valid hourly averages from the CEMS are counted as quality-assured data. This includes clock hours in which the default value of 2.0 ppm has been substituted because the hourly averages from the CEMS fall below 2.0 ppm, provided that the monitor is operating and is not out-of-control with respect to any of its required quality assurance tests (i.e., daily calibration, linearity and RATA).

If, for a particular unit with an SO_2 CEMS, the owner or operator selects one of the other two SO_2 compliance options for gas-fired hours, in lieu of using the SO_2 monitor (i.e., either using the default emission factor for pipeline natural gas or using appendix D procedures, in accordance with § 75.11 (e)(1) or (e)(2), respectively), § 75.30(d) of today's rule specifies that CEMS readings obtained during gas-fired hours are to be excluded from the historical CEMS data banks, for purposes of providing substitute data. In addition, today's rule amends § 75.32(a)(3) to state that gas-fired hours are to be excluded from the calculation of percent SO_2 data availability for the CEMS when the SO_2 compliance option in § 75.11 (e)(1) or (e)(2) is selected. These provisions are not substantially different from the provisions in § 75.30(d) and § 75.32(a)(4), respectively, of the interim final rule.

C. Clarifying the Procedures for Performing Cycle Time Tests

Background: The cycle time test is a certification test that measures the amount of time it takes for a CEMS to respond to step changes in concentration. The original cycle time test in section 6.4 of appendix A in the January 11, 1993 final rule measured the length of time necessary for a monitor to achieve 95 percent of the step change in pollutant concentration between stack emissions and a calibration gas, beginning when the calibration gas is released from the cylinder. The May 17, 1995 interim final rule changed the procedures for conducting a cycle time test to eliminate the time it takes the calibration gas to travel from the cylinder to the probe tip of the CEMS. This time period was eliminated in order to achieve more representative cycle time test results. (See 60 FR 26565.)

In the original January 11, 1993 rule, the purpose of the cycle time test was to measure the amount of time it takes for a monitor to achieve 95 percent of the step change in concentration going from measured stack emissions to a high-level or low-level calibration gas. The cycle time test procedure in the interim final rule was reversed in that it measures the amount of time it takes the monitor to achieve 95 percent of the step change in concentration when going from a high-level calibration gas (downscale test) or low-level calibration gas (upscale test) to a stable measured emissions reading.

In order to implement the revised requirements, section 6.4 of appendix A in the interim final rule specified that the cycle time test procedures be performed and evaluated as follows:

1. Inject a high scale or low scale calibration gas into the probe tip of the monitoring system until a stable response is achieved.
2. After a stable response is achieved, stop the calibration gas flow and record the time.
3. Allow the monitor to stabilize while reading the stack emissions. (The monitor is determined to be stable when either the measured reading deviates less than 1 percent of span for 30 seconds or if the measured concentration reading deviates less than 5 percent of the measured average concentration for a 5 minute interval.)
4. Calculate 95 percent of the step change in concentration and determine the time at which 95 percent of the step change is achieved.
5. Repeat the procedure with the other calibration gas.
6. The response time must be achieved in under 15 minutes for both the downscale and upscale tests.
7. The longest 95 percent step change time from either the low scale or high scale test is the component's cycle time.
8. For the NO_X-diluent CEMS and SO_2-diluent CEMS test, record and report the longer cycle time of the two component analyzers as the system cycle time.
9. For time shared systems, this procedure must be done for all probe locations that will be polled within the same 15-minute period during monitoring system operations.
10. For monitors with dual ranges, perform the test on the range giving the longest cycle time.

Issue: In response to the cycle time test procedures established in the interim final rule, the Agency received significant comments. One commenter noted that the stabilization criteria cited in the May 17, 1995 interim final rule do not allow monitoring systems that record data in 1-minute or 3-minute intervals sufficient time to record data to document a stable concentration reading. (See Docket A–94–16, Item V–D–18.) The commenter also recommended that the procedures for calculating 95 percent of the step change in concentration be clarified. EPA also received comments concerning the order in which calibration gases are introduced during the cycle time test. Some commenters were satisfied with the test in the interim final rule which requires the source to initiate the cycle time test by injecting a zero level or high level calibration gas and then allowing the monitor to stabilize while reading stack emissions. (See Docket A–94–16 Item V–D–02). Other commenters stated that the cycle time test in the interim rule is problematic because the stable ending value is difficult to determine. (See Docket A–94–16 Item V–D–12).

Response: In response to the comments received, today's rule revises the criteria used to determine when the stack emissions have stabilized after a downscale or upscale test, in order to accommodate monitoring systems that record concentration data in 1-minute or 3-minute intervals. (See Docket A–94–16, Item V–D–18.) The EPA concurs that monitoring systems that store data in 1-minute or 3-minute intervals cannot record a sufficient number of data points to meet the stabilization criteria cited in section 6.4 of appendix A in the May 17, 1995 interim final rule. Therefore, in today's rule concentration data readings are considered to be stable after a downscale or upscale test if the analyzer reading deviates by less than 2 percent of the analyzer's span value for a minimum of 2 minutes or if the analyzer's measured concentration reading deviates less than 6 percent from the average measured concentration for 6 minutes. Owners and operators of CEMS that do not record concentrations in 1-minute or 3-minute intervals may petition the Administrator under § 75.66 for permission to use alternative cycle time test stabilization criteria. Today's rule adds a diagram and narrative explanation of the cycle time test procedure to section 6.4 of appendix A to provide additional guidance on how to calculate 95 percent of the step change in concentration and how to calculate the cycle time. EPA concurs with the commenters who stated that the cycle time test in today's rule does not present a burden to the source. The Agency maintains that the cycle time test in today's rule will provide more representative cycle response time; therefore, EPA has not changed the order in which the calibration gases are injected into the probe during a cycle time test.

D. Revising the Reporting of Scrubber Parameters and Missing Data for Add-On Emission Controls

Background: Section 75.34(a)(1) of the January 11, 1993 rule allowed the owner or operator of a unit with add-on emission controls to use standard missing data procedures in §§ 75.31 and 75.33 when outlet SO_2 or NO_X CEMS are out of service and the parametric data shows that the add-on emission controls for the unit are operating properly. The May 17, 1995 interim final rule amended this section by requiring the owner or operator of a unit that uses the standard missing data procedures to demonstrate that the emission control device operating parameters were maintained within certain ranges indicative of normal, stable control device operation. In addition, the designated representative must certify proper operation of the add-on emission controls during missing data periods. Section 75.34 (a)(1) of the interim final rule required the parameter ranges to be part of the monitoring plan for the unit (60 FR 26562; May 17, 1995).

Issue: One commenter expressed the concern that if operating parameter ranges are required to be included in the part 75 monitoring plan, title V permitting authorities might include the operating parameters in the title V operating permit. (See Docket A–94–16, Item V–D–13.) This could result in the normal operating parameter ranges becoming permit conditions, the violation of which could result in an enforcement action.

Response: In order to assure that emissions are not underestimated, and to allow the use of standard missing data procedures, it is essential to verify proper operation of the add-on emission controls during missing data periods. Therefore, today's rule maintains the requirement to establish operating parameter ranges representative of periods of proper operation of the add-on emission controls. The EPA notes that the determination of whether parameters should be referenced in a title V operating permit is up to the permitting authority under title V, which will generally be a State or local agency. Since, for purposes of the Acid Rain Program, this information will most likely be used in field audits, EPA believes that it is reasonable to keep this information on-site in the QA/QC plan rather than including it in the part 75 monitoring plan to be submitted to EPA and the State. In addition, by no longer requiring the information in the monitoring plan that is sent to EPA, this approach reduces the burden on utilities. Therefore, today's rule requires that the parameter ranges be kept on-site as a part of the QA/QC program required in section 1 of appendix B of part 75. This information must be available to EPA and to State and local agencies upon request or during a field audit.

Issue: A comment was received on § 75.34(d). The commenter stated that the requirement for parametric monitoring will unnecessarily increase the owner or operator's administrative costs and workload. (See Docket A–94–16, Items V–D–13 and V–D–07.) The commenter stated that obtaining the data will increase data collection and paperwork for data storage since some affected units do not have continuous electronic data collection for many of the add-on emission control operating parameters.

Response: The EPA believes that verification of proper operation of add-on emission controls generally requires monitoring and recording of various operating parameters. The January 11, 1993 final rule and the May 17, 1995 interim final rule required that the data be recorded on a continuous basis. The January 11, 1993 final rule and the May 17, 1995 interim final rule also required utilities to keep records of the parametric data corresponding to missing data periods for a period of three years. Since this requirement did not change from the original January 11, 1993 final rule, this is not an increased recordkeeping burden. The EPA does recognize the recordkeeping burden imposed on the source when the data is required to be recorded and reported on a continuous basis, but believes this is reasonable in light of the importance of having an objective basis for determining whether the add-on controls are operating properly.

In today's rule, the add-on control parameter recordkeeping provisions are as follows. As in the January 11, 1993 final rule, if an owner or operator wants to use the standard missing data procedures, he must record and keep the parametric monitoring data for each missing data period. This data, which must be in an accessible form and kept for three years from the creation of the record, must show that the controls are operating within the parameter ranges. In addition, the designated representative must certify that the add-on controls were operating properly.

The EPA notes that the final rule preserves the following alternative provisions: (1) Using maximum potential concentration or maximum inlet readings from the previous 720 hours of quality-assured data during missing data periods; or (2) using backup CEMS to reduce the number of missing data periods. Either of these approaches will reduce the recordkeeping burden associated with maintaining parametric data for each hour of missing CEMS data.

E. Clarifying the Procedures Dealing With the Use of Reference Method 9 Instead of Continuous Opacity Monitors on Bypass Stacks

Background: This issue concerns whether Method 9 in appendix A of part 60 can be used for monitoring opacity on a bypass stack. Section 75.18(3)(b) of the January 11, 1993 final rule required an owner or operator to install and operate a COMS on a bypass stack. The May 17, 1995 direct final rule relaxed this requirement by allowing the use of Method 9 on bypass stacks. The EPA received a significant adverse comment on § 75.18(b)(3); therefore, this section of the rule was withdrawn as required. Today's rule reinstates § 75.18(b)(3).

Issue: The EPA received significant adverse comments on § 75.18(b)(3) of the direct final rule. (See Docket A–94–16, Item V–D–18.) The EPA also received a comment in support of using Method 9 instead of a COMS on bypass stacks. (See Docket A–94–16, Item V–D–21.) One commenter expressed concern that Method 9 is not equivalent to installing a COMS and suggested that § 75.18(b)(3) be removed. The commenter noted that EPA has not specified how often Method 9 has to be performed and suggests § 75.18(b)(3) be revised to require continuous or subsequent visual opacity readings. The commenter also noted that Method 9 cannot be used at night or during inclement weather and that EPA does not address what an owner or operator should do during these times. The commenter suggested that EPA should not allow the owner or operator to have emissions pass through the bypass stack during periods when Method 9 cannot be performed.

Response: The EPA agrees with the commenter that Method 9 is as effective as continuous opacity monitoring. However, Method 9 tends to yield a positive observation error and therefore would not result in underestimation of opacity when taken. Since bypass stacks operate infrequently, and generally only in emergency situations, it is an unnecessary economic burden for the sources to install and maintain a COMS. For the purpose of the Acid Rain Program, opacity is not required for all hours of operation. Thus, there are no missing data procedures for COMS and Method 9 is an acceptable method of monitoring opacity for bypass stacks which are seldom used. Therefore, EPA has concluded that the utility should have the flexibility allowed under § 75.18(b)(3). Today's rule reinstates the provision allowing Method 9 to be used to monitor opacity on a bypass stack whenever emissions pass though the bypass stack. Section 75.18(b)(3) of today's rule specifies that the utility must conduct Method 9 in accordance with applicable State regulations for visual observations of opacity. This would include State requirements for the frequency of performing Method 9 and for procedures to follow when it is not possible to perform Method 9. EPA expects to target for audit units that use the bypass stacks for greater than 5% of the time. If the agency finds a pattern of excessive use of the bypass stacks, EPA may revisit the issue of allowing Method 9 for bypass stacks. States have the authority to require COMS.

F. Addressing Minor Comments on the Direct Final Rule

The EPA received a number of minor comments on the May 17, 1995 direct final rule. In some cases, the commenters asked for clarification of provisions or terms used in the direct final rule. In other cases, commenters requested that EPA take policies from the ''Acid Rain CEM (Part 75) Policy Manual'' (Docket A–94–16, Items II–D–54 and V–A–1) related to provisions in the direct final rule and incorporate these policies into part 75. These provisions include: allowing the use of ''AGA Report No. 7'' for calibration of turbine fuel flowmeters; clarifying reporting provisions for a common stack monitoring situation where emissions may be subtracted; and specifying means for apportioning heat input from a common stack to its constituent units. In addition, a commenter pointed out a case where the direct final rule's requirements for recertification of COMS might be more extensive than necessary.

1. Use of AGA Report No. 7

Background: Appendices D and E of part 75 allow the use of fuel flowmeters, in addition to other data such as sulfur content or gross calorific value of fuel samples or stack testing data, to determine SO_2 mass emissions, NO_X emission rate, and heat input from certain gas-fired and oil-fired units instead of requiring monitoring with CEMS. Utilities choosing to use fuel flowmeter monitoring systems instead of CEMS must demonstrate that the fuel flowmeters can accurately measure fuel flow rate. This requires an initial calibration and periodic (annual) quality assurance testing.

In general, EPA accepts industry standards for calibration of fuel flowmeters, such as those from the AGA or the American Society of Mechanical Engineers (ASME). Because these industry standards for fuel flowmeters are used to transfer fuel for sale, the standards are written to provide for the accurate calibration and measurement of fuel flow. The EPA considers this level of accuracy sufficient for the Acid Rain Program.

Issue: The AGA requested that EPA allow the use of ''AGA Report No. 7'' for calibration of turbine flowmeters for use in appendices D and E of part 75. (See Docket A–94–16, Item V–D–5.)

Response: The EPA had previously approved use of ''AGA Report No. 7'' as an alternative to the prescribed ASME calibration methods through a petition from a utility under § 75.66. Then, the Agency announced that this was an acceptable method for calibration in Question 10.12 in Update 6 of the ''Acid Rain CEM (Part 75) Policy Manual''. (See Docket A–94–16, Item V–A–1.) Consequently, EPA agrees with the commenter and today's rule incorporates this method by reference in § 75.6 for use in § 75.20(g) and appendix D of part 75. The Agency notes that the specific section for calibration requirements is section 8 of ''AGA Report No. 7''.

2. Provisions for Reporting and Monitoring of Subtracted Emissions at a Common Stack

Background: Section 75.16 contains provisions for the monitoring of SO_2 mass emissions and heat input in cases where more than one unit uses the same stack. This is referred to as a ''common stack''. The EPA revised these provisions in the May 17, 1995 direct final rule to allow more options for monitoring in this type of situation. (See section C(4)(a) of the ''Technical Support Document'', Docket A–94–16, Item II–F–2.) The options of §§ 75.16(a)(2)(ii)(B) and (a)(2)(ii)(C) allow the owner or operator to install SO_2 and flow monitoring systems at the common stack and at some of the individual units using the common stack to monitor SO_2 mass emissions at each location. The owner or operator would then calculate the SO_2 mass emissions from the remaining units by subtracting the SO_2 mass emissions measured at the individual units from the SO_2 mass emissions measured at the common stack. For example, if a Phase II unit and a Phase I unit share a common stack, the utility could monitor SO_2 mass emissions from flow and SO_2 monitoring systems at the common stack, monitor SO_2 mass emissions from flow and SO_2 monitoring systems in the ducts from the Phase I unit, and then subtract the SO_2 mass emissions of the Phase I unit from the common stack SO_2 mass emissions to determine the mass emissions from the Phase II unit.

Issue: One commenter mentioned a potential problem with the options of §§ 75.16(a)(2)(ii)(B) and (a)(2)(ii)(C). The commenter was familiar with such installations and mentioned that this method may sometimes produce a negative value for SO_2 emissions or heat input if the SO_2 or flow monitoring system in the duct has a bias adjustment factor. (See Docket A–94–16, Item V–D–18.) The commenter recommended that EPA clarify in §§ 75.16(a)(2)(ii)(B) and (a)(2)(ii)(C) that negative emission and heat input values be set to zero in this case.

Response: The EPA agrees with the commenter and has clarified these provisions in today's action. Negative emission values do not exist in reality and reporting negative SO_2 mass emission values makes no sense. Therefore, the revised provision indicates that SO_2 mass emission values shall not be reported as a value less than zero. This is also similar to provisions in the ''CEMS Submission Instructions'' (Docket A–94–16, Item II–D-99), which require utilities to adjust negative concentration, flow, heat input or emission values to a value of zero (0). In addition, today's rule makes the same revision to the parallel provision in § 75.16(b)(2)(ii)(B), for a situation where affected Phase II units share a common stack with one or more non-affected units, and SO_2 mass emissions from the non-affected units are subtracted from SO_2 mass emissions on the common stack.

3. Heat Input Apportionment at Common Stacks

Background: Another issue related to common stacks concerns heat input. Heat input can be determined using a flow monitor and a CO_2 or O_2 diluent monitor. In order to determine if a utility system (or dispatch system) has underutilization during Phase I under part 72 (§§ 72.91 and 72.92, in particular), and if so, how many allowances should be surrendered, it is necessary to have heat input on an individual unit basis. Individual unit heat input is still necessary, even in the case where units share a common stack and heat input is measured by monitors on the common stack. In § 75.16(e) of the May 17, 1995 direct final rule, EPA clarified this requirement. (See section C(4)(a) of the ''Technical Support Document,'' Docket A–94–16, Item II–F–2.) In Question 17.5 of the ''Acid Rain CEM (Part 75) Policy Manual,'' EPA approved two methods for apportioning heat input to individual units that feed into a common stack, where all units combust the same type of fuel. (See Docket A–94–16, Item IV–D–54.) These methods apportion total heat input measured at the common stack by using the ratio of the individual unit usage to the usage of all the units using the common stack. For most plants, the measure of unit usage is electrical generation in megawatts (MWe), and for other plants, the measure of unit usage for the apportionment is the flow of steam associated with each unit.

Issue: A commenter requested that EPA incorporate these apportionment methods into part 75. (See Docket A–94–16, Item V–D–18.)

Response: The EPA agrees with the commenter and today's rule has incorporated this heat input apportionment methodology in § 75.16(e)(5). The Agency has already accepted this apportionment method through policy as sufficiently accurate for heat input, provided that all units use the same kind of fuel. Because different fuels have different combustion characteristics and their emission calculation formulas will use a different combustion ratio, called the ''F-factor,'' this heat input apportionment methodology is not appropriate if different fuels with a different F-factor are used. Incorporating the heat input apportionment provision allows utilities to implement this apportionment without going through a formal petition approval process. An apportionment methodology based upon the ratio of electrical generation or steam flow is already incorporated in part 75 for fuel flow measured by flowmeters on common pipes in section 2.1.2.2 of appendix D. For these reasons, EPA is incorporating the heat input methodology in § 75.16(e)(5).

4. Recertification of Opacity Monitoring Systems

Background: Section 75.20(b) contains requirements for recertification of CEMS and COMS. This paragraph requires recertification whenever a significant change is made to a monitoring system or to the conditions under which it is monitoring that will affect the ability of the monitoring system to accurately measure, record and report emissions or opacity. An example of a significant change to a monitoring system's conditions for monitoring is if the ductwork to a stack is modified so that a new unit emits through the stack, in addition to the existing units. In this case, the change to the flue gas handling system could significantly change the flow and concentration profiles in the stack, thus affecting the ability of the monitor to measure, record and report emissions.

In general, the Acid Rain Program is designed to be as consistent as possible with State requirements for monitoring opacity. Although section 412 of the Act requires installation of opacity monitors for all affected units, the Act does not provide for a standard or limitation on opacity for the Acid Rain Program. In order to make use of opacity monitoring data from affected units, part 75 requires that opacity data be reported to State agencies in the format specified by the State. In addition, if a State agency certifies an opacity monitoring system to the requirements of Performance Specification 1 in appendix B of part 60, that certification also applies to the Acid Rain Program.

Issue: A commenter also noted that § 75.20(b) of the May 17, 1995 direct final rule requires recertification of a COMS due to changes in unit operation. The commenter suggested that the results of the certification tests for opacity monitoring systems are not significantly affected by changes in pollutant emission levels, and therefore, the requirement for recertification upon a change in unit opacity should be deleted.

Response: The EPA agrees with the commenter that changes in emissions, such as from a fuel change, do not significantly affect, and so should not require recertification, of the opacity monitoring system. Today's rule removes this requirement from § 75.20(b).

For similar reasons, EPA is also removing the requirement for recertification of opacity monitoring systems due to modifications in the flue gas handling system, except for those modifications to ductwork that change the path length of the opacity monitoring system. After further consideration of opacity recertification requirements, the Agency has determined that only these modifications would significantly affect the opacity monitoring system's ability to monitor, record and report opacity. The EPA notes that a utility must still meet any State requirements for recertification of an opacity monitoring system.

G. Addressing Comments on RATA Notifications

Background: The May 17, 1995 direct final rule included provisions requiring notification of the date on which periodic Relative Accuracy Test Audits (RATAs) will be performed in §§ 75.21(d) and 75.61(a)(5). The direct final provisions require submission of written notification to the Administrator, the appropriate EPA Regional Office, and the applicable State or local air pollution control agency at least 21 days before the scheduled date of a RATA. The date may be rescheduled if written or oral notice is provided to EPA and to the appropriate State or local air quality agency at least seven days before the earlier of the original scheduled date or the new test date.

The Texas Subgroup commented adversely upon the requirements in §§ 75.21(d) and 75.51(a)(5) for notifications of the date on which periodic RATAs will be performed. These provisions were removed from part 75 in a May 22, 1996 amendment to part 75 (60 FR 25580–25585). As part of the document in the Federal Register, EPA took public comment for an additional 15 days.

Public comment focused upon five main issues related to the notifications for periodic RATAs: need for the notification provision; the agencies or offices to which a notification should be sent; whether agencies or offices could grant a waiver from the testing notification; how the time periods for notification could be changed to allow greater flexibility to utilities; and the means by which or form in which a notification could be transmitted to an agency. Comments were received from three utility commentors and from four State or local air pollution agencies (See Docket A–94–16 Items V–D–25 through V–D–27 and V–D–29 through V–D–32).

Issue: One of the utility commentors felt that the RATA notification provision was not that critical. This utility commentor expressed concern over lack of flexibility (See Docket A–94–16 Item V–D–26). The State and local agencies all supported having a RATA notification (See Docket A–94–16 Items V–D–29 through V–D–32).

Response: As stated in the Federal Register (60 FR 25581), EPA believes it is critical for EPA, State, and local agency personnel to be able to observe periodic RATAs in order to ensure the quality of monitored data for the Acid Rain Program. In addition, the EPA believes that advance notification of the date of periodic RATA testing allows the cost-effective use of agency resources by coordinating auditing of monitor performance with regularly scheduled quality assurance testing and by coordinating field observations at multiple locations. Thus, EPA is reinstating the requirements for notification of the date of periodic RATA testing.

Issue: Two related issues concerned to which agencies notifications should be sent, and whether agencies or offices could grant a waiver from the testing notification. In the Federal Register document requesting comment on the periodic RATA notification, EPA specifically requested comment on removing the requirement that notifications be provided to the Administrator (received by EPA's Acid Rain Division) and allowing a State or local air pollution control agency or EPA regional office to waive the notification requirement. One utility commentor felt that the RATA notification might be necessary for its State agency, but not for the Federal EPA (See Docket A–94–16 Item V–D–25). One State agency supported the idea of allowing a region to determine to which agency should be notified (See Docket A–94–16 Item V–D–29). A utility supported allowing a State or local agency or EPA regional office to issue a waiver (See Docket A–94–16 Item V–D–27).

Response: EPA considered the comment requesting that notifications go only to State agencies. However, some EPA Regional offices are active in observing RATA testing. Therefore, EPA is retaining the requirement to send notifications of periodic RATA testing to EPA.

Based upon the public comments, EPA is creating a provision that would allow a state or local agency, an EPA regional office, or the Administrator's delegatee (EPA's Acid Rain Division) to waive the requirement for periodic RATA notification for a unit or a group of units. In general, a state or local agency could waive the requirement for notification to its own office, but could not waive the requirement for notification to the EPA. Similarly, an EPA Regional office could waive the requirement for notification to its office, but could not waive the requirement for notification to a State or local agency or to the Administrator's delegatee. The waiver should specify the units for which the periodic RATA notification requirement is waived and the test or period of time for which the periodic RATA notification requirement is waived. For example, a regional EPA office might send a letter to the designated representatives of several utilities specifying that the designated representative or owner or operator would not be required to submit notice until and unless the regional office sends another letter specifying that notification is requested. A State agency might grant a waiver from the testing requirement for one particular unit in that state for its RATA testing in the first quarter of 1997. EPA's Acid Rain Division could issue a policy statement through the Acid Rain Program Policy Manual if it wanted to waive the requirement for notification to the Administrator indefinitely.

Today's rule also specifies that a state agency or EPA may discontinue the waiver from the periodic RATA notification. However, the periodic RATA notification requirement would only resume for any future testing; a utility would never retroactively be required to provide notification. The state agency or EPA would need to send another written statement specifying for which units or groups of units the waiver no longer applies. Thus, if an agency's priorities for observing testing change over time, the agency would be able to grant case-by-case waivers, grant long-term waivers or discontinue long-term waivers to be consistent with those new priorities for observing. EPA believes that allowing this flexibility will encourage States and regional EPA offices to issue waivers in cases where they are certain they will not be observing tests for a unit or group of units for a year or more.

Issue: An issue of great concern to commentors was revising the time limits for notification to allow greater flexibility. One utility commentor felt that putting any time limit for providing notification was problematic, since a utility could be in violation of that time limit. This commentor suggested that if notification were necessary at all, the notification should be a general schedule of testing provided ahead of time (See Docket A–94–16 Item V–D–26). Another utility commenter expressed concern that the requirement for 21 days advance notification under the Acid Rain Program is different from their State agency requirement for a 30-day notification, and that coordinating the different requirements is difficult (See Docket A–94–16 Item V–D–25). State agencies supported having an initial notification requirement of 21 days (See Docket A–94–16 Items V–D–29, V–D–30, V–D–32) or 30 days (See Docket A–94–16 Item V–D–31). One state felt that a 21-day advance notification was reasonable because utilities generally plan at least this far in advance for periodic RATAs (See Docket A–94–16 Item V–D–29).

Several State agencies were sensitive to utility's need for greater flexibility for sending notification where testing has been rescheduled. Some States suggested that it would be sufficient for a utility to notify them as late as twenty-four hours before the new date of the test (See Docket A–94–16 Items V–D–31 and V–D–32), in order to allow utilities greater flexibility in rescheduling. Another state suggested that there should be different requirements for notification, depending on whether the scheduled date is changed by less than three days or changed by three days or greater. In the first case, a two-day notification would not be appropriate, but in the latter case it would be appropriate. This state also commented that in some cases, an observer might already be on site when a test needs to be postponed until the next day (See Docket A–94–16 Item V–D–30). In this case, notification should not be required.

Response: For the initial notification of the date of periodic RATA testing, EPA has decided to retain the requirement for advance notification of at least twenty-one days. EPA agreed with the commentor who felt this requirement was reasonable. EPA notes that twenty-one days advance notification is sufficiently far in advance that agencies can schedule an observer, which is the primary purpose of requiring notification. Although the Agency understands the concerns of utilities with having a time limit, the Agency believes there must be some time limit established in order for the notification to meet its purpose of allowing agencies to observe testing.

Also, EPA would like to clarify that this requirement is for notification *no later than* twenty-one days in advance. Thus, if a state agency has a requirement for notification thirty days in advance, a utility could send notification both to the State and to EPA thirty days in advance. Furthermore, if a utility wanted to send a schedule of testing for all of its units during the next calendar quarter in a single notification, it could do so. In either case, the minimum information that must be present in the notification is as follows: (1) the name of the plant and unit at which RATA testing will be performed; (2) the ORISPL number for the plant; and (3) the date or dates for which RATA testing is scheduled for that unit. It would not be necessary to use the optional EPA form for RATA testing notifications if the schedule letter or State notification letter contained the above information.

EPA also agrees with the commentors who suggest that twenty-four hours is sufficient advance notification when a test is rescheduled, where rescheduling is done shortly before the original test date. If the utility knows the rescheduled test date earlier, it should notify agencies when it knows this date. However, the twenty-four hour notice is a minimum requirement. This should prevent any situations where a utility might be required to wait before starting testing or else risk a technical violation. Using a single time period of twenty-four hours (the calendar day before) would also be more straightforward than having different notification requirements, depending upon how many days the test date is changed. In addition, today's rule includes a provision allowing for waivers of the notification requirement where an observer is on-site. If an observer were actually already on site and testing were postponed, then the observer could choose to waive the notification requirement for that test for *all* agencies (state, local, EPA regional office and the EPA Administrator's delegatee).

Issue: EPA also received comments on the means by which or the form in which a notification could be transmitted to an agency. The May 17, 1995 direct final rule contained a provision requiring an initial written notification of the date of testing, and notification again if a test is rescheduled either ''in writing or by telephone or other means.'' In the May 22, 1996 Federal Register notice requesting public comment, EPA requested comment on using means of notification such as telephone, facsimile, or electronic mail notification for a test that is rescheduled. One utility commentor suggested that they would prefer to send a notification by electronic mail, either for initial notification or in case of rescheduling, and eliminate paper notifications altogether (See Docket A–94–16 Item V–D–25). State commentors felt that notifications could be submitted either by letter, electronic mail or telephone (See Docket A–94–16 Item V–D–29); others explicitly stated that these means were appropriate for a notification where a testing date is rescheduled, but not for the original notification (See Docket A–94–16 Items V–D–30 and V–D–32).

Response: Based upon the comments received, EPA is retaining the provisions that initial notification of the testing date must be provided in writing. However, EPA is clarifying in today's rule that a written notification may be provided in the mail (U.S. mail or overnight mail carrier) or via facsimile. In addition, an agency may choose to accept electronic mail to meet the requirement for an initial written notification. Notification in case of rescheduled testing may be provided in writing, by telephone, or by other means that is acceptable to the agency receiving the notification. Because the initial notification is most critical for an agency that wants to schedule test observations, it is still required to be submitted in writing, rather than over the telephone. If a utility wishes to use electronic mail or some other form of notification not explicitly mentioned in part 75, it should contact its state or local agency and EPA Regional office to determine if this is acceptable. The agency may request additional safeguards be used when electronic mail notice is provided (e.g., requiring procedures for confirmation of receipt or a follow-up letter in the mail later).

IV. Impact Analyses

A. 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.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a ''significant regulatory action'' because the rule seems to raise novel legal or policy issues. As such, this action was submitted to OMB for review. Any written comments from OMB to EPA, any written EPA response to those comments, and any changes made in response to OMB suggestions or recommendations are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section.

B. Unfunded Mandates Act

Section 202 of the Unfunded Mandates Reform Act of 1995 (''Unfunded Mandates Act'') requires that the Agency prepare a budgetary impact statement before promulgating a rule that includes a Federal mandate that may result in expenditure by State, local, and tribal governments, in aggregate, or by the private sector, of $100 million or more in any one year. Section 203 requires the Agency to establish a plan for obtaining input from and informing, educating, and advising any small governments that may be significantly or uniquely affected by the rule.

Under section 205 of the Unfunded Mandates Act, the Agency must identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a budgetary impact statement must be prepared. The Agency must select from those alternatives the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule, unless the Agency explains why this alternative is not selected or the selection of this alternative is inconsistent with law.

Because this final rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less than $100 million in any one year, the Agency has not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, the Agency is not required to develop a plan with regard to small governments. However, as discussed in this preamble, the rule has the net effect of reducing the burden of part 75 of the Acid Rain regulations on regulated entities that have add-on emission controls, including both investor-owned and municipal utilities.

C. Paperwork Reduction Act

Today's final rule does not add any additional information collection requirements to the current information collection requirements in the existing part 75. Therefore an Information Collection Request was not prepared for today's final rule.

The information collection requirements for the existing part 75 rule have been approved by the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, and have been assigned control number 2060–0258.

The information collection requirements in today's final rule do not increase the estimated reporting burden. In fact, today's final rule slightly reduces the reporting burden by allowing utilities which have units with add-on emission controls which want to use the missing data procedures described in this final rule to keep the parametric data ranges on site rather than to report it to EPA. Since the reduction is voluntary and only affects units with add-on emission controls, it is difficult to determine the specific amount of the reduction in burden overall.

Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to Director, OPPE Regulatory Information Division; U.S. Environmental Protection Agency; 401 M Street SW (Mail Code 2136); 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.''

D. Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601, et seq., requires federal agencies to consider potential impacts of proposed regulations on small business entities. If a preliminary analysis indicates that a proposed regulation would have a significant adverse economic impact on a substantial number of small business entities, then a regulatory flexibility analysis must be prepared. An action which has a predominantly deregulatory or beneficial economic effect on small business does not need a regulatory flexibility analysis.

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. This rule will reduce regulatory burdens on small business entities because the provisions in today's final rule increase the implementation flexibility and slightly relieve the regulatory burden for all utilities affected by this rule, including small utilities. Therefore, EPA has determined that this rule will have no significant adverse economic effect on a substantial number of small business entities.

E. Small Business Regulatory Enforcement Fairness Act

Under 5 U.S.C. 801(a)(1)(A) as added by the Small Business Regulatory Enforcement Fairness Act of 1996, EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the General Accounting Office prior to publication of the rule in today's Federal Register. This rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 75

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

Dated: November 5, 1996.

Carol M. Browner,

Administrator.

The interim final rule (59 FR 26560, May 17, 1995) is adopted as final with the following changes. For the reasons set out in the preamble, part 75 of title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 75—CONTINUOUS EMISSION MONITORING

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

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

2. Section 75.6 is amended by revising paragraph (e) to read as follows:

§ 75.6 Incorporation by reference.

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(e) The following materials are available for purchase from the following address: American Gas Association, 1515 Wilson Boulevard, Arlington VA 22209:

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition) and Part 3: Natural Gas Applications (August 1992 Edition), for § 75.20 and appendices D and E of this part.

(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (1985 Edition), for § 75.20 and appendix D of this part.

3. Section 75.11 is amended by revising paragraphs (a), (d), and (e); and by removing paragraph (g) 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 sulfur content no greater than 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.

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(d) *Gas-fired and oil-fired units.* The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall measure and record SO_2 emissions:

(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 sulfur content no greater than natural gas); or

(2) By providing other information satisfactory to the Administrator using the applicable procedures specified in appendix D of this part for estimating hourly SO_2 mass emissions. Appendix D shall not, however, be used when the unit combusts gaseous fuel with a sulfur content greater than 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.

(e) Units with SO_2 continuous emission monitoring systems during the combustion of gaseous fuel. The owner or operator of an affected unit with an SO_2 continuous emission monitoring system shall, during any hours in which the unit combusts only gaseous fuel, determine SO_2 emissions in accordance with paragraph (e)(1), (e)(2), (e)(3) or (e)(4) of this section, as applicable.

(1) When pipeline natural gas is burned 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 using the heat input calculated using a certified flow monitoring system and a certified diluent monitor, in conjunction with the default SO_2 emission rate for pipeline natural gas from section 2.3.2 of appendix D of this part, and Equation F–23 in appendix F of this part. When this option is chosen, the owner or operator shall perform the necessary data acquisition and handling system tests under § 75.20(c), and shall meet all quality control and quality assurance requirements in appendix B of this part for the flow monitor and the diluent monitor.

(2) When gaseous fuel with a sulfur content no greater than 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 of this part, by following the fuel sampling and analysis procedures in section 2.3.1 of appendix D of this part, by meeting the recordkeeping requirements of § 75.55, and by meeting all quality control and quality assurance requirements for fuel flowmeters in appendix D of this part. If this compliance option is selected, the hourly unit heat input reported under § 75.54(b)(5) 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 sulfur content no greater than 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, 1999, the SO_2 monitoring system shall be subject to the following provisions; prior to January 1, 1999, the owner or operator may comply with these provisions:

(i) When conducting the daily calibration error tests of the SO_2 monitoring system, as required by section 2.1.1 in appendix B of this part, the zero-level calibration gas shall have an SO_2 concentration of 0.0 percent of span. This restriction does not apply if gaseous fuel is burned in the affected unit only during unit startup.

(ii) The zero-level calibration response of the SO_2 monitoring system shall be adjusted, either automatically or manually, to read exactly 0.0 ppm SO_2 following each successful daily calibration error test conducted in accordance with section 2.1.1 in appendix B of this part. This calibration adjustment is optional if gaseous fuel is burned in the affected unit only during unit startup.

(iii) Any hourly average SO_2 concentration of less than 2.0 ppm recorded by the SO_2 monitoring system shall be adjusted to a default value of 2.0 ppm, for reporting purposes. Such adjusted hourly averages shall be considered to be quality-assured data, provided that the monitoring system is operating and is not out-of-control with respect to any of the quality assurance tests required by appendix B of this part (i.e., daily calibration error, linearity and relative accuracy test audit).

(iv) Notwithstanding the requirements of sections 2.1.1.1 and 2.1.1.2 of appendix A of this part, a second, low-scale measurement range is not required for units that sometimes burn natural gas (or gaseous fuel with a sulfur content no greater than natural gas) and at other times burn higher-sulfur fuel(s) such as coal or oil. For units that burn only natural gas (or gaseous fuel with a sulfur content no greater than 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 sulfur content greater than 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.

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4. Section 75.16 is amended by revising paragraphs (a)(2)(ii)(B), (a)(2)(ii)(C), and (b)(2)(ii)(B) and by adding paragraph (e)(5) 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.

(a) * * *
(2) * * *
(ii) * * *

(B) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system and flow monitoring system in the duct from each Phase II or nonaffected unit; calculate SO_2 mass emissions from the Phase I 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 Phase II and nonaffected units; record and report the calculated SO_2 mass emissions from the Phase I units, not to be reported as an hourly average value less than zero; and combine emissions for the Phase I units for compliance purposes; or

(C) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system and flow monitoring system in the duct from each Phase I or nonaffected unit; calculate SO_2 mass emissions from the Phase II 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 Phase I and nonaffected units, not to be reported as an hourly average value less than zero; and combine emissions for the Phase II units for recordkeeping and compliance purposes; or

* * * * *

(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; and combine emissions for the Phase I and Phase II affected units for recordkeeping and compliance purposes; or

* * * * *

(e) * * *

(5) The owner or operator of an affected unit with a diluent monitor and a flow monitor installed on a common stack to determine heat input at the common stack may choose to apportion the heat input from the common stack to each affected unit utilizing the common stack by using either of the following two methods, provided that all of the units utilizing the common stack are combusting fuel with the same F-factor found in section 3 of appendix F of this part. The heat input may be apportioned either by using the ratio of load (in MWe) 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/hr) for each individual unit to the total steam flow for all units utilizing the common stack.

5. Section 75.18 is amended by adding paragraph (b)(3) to read as follows:

§ 75.18 Specific provisions for monitoring emissions from common and bypass stacks for opacity.

* * * * *

(b) * * *

(3) The owner or operator monitors opacity using Method 9 of appendix A of part 60 of this chapter whenever emissions pass through the bypass stack. Method 9 shall be used in accordance with the applicable State regulations.

6. Section 75.20 is amended by revising the introductory text of paragraph (b) and by revising paragraph (g)(1)(i) to read as follows:

§ 75.20 Certification and recertification procedures.

* * * * *

(b) *Recertification approval process.* Whenever the owner or operator makes a replacement, modification, or change in the certified continuous emission monitoring system or continuous opacity monitoring system (which includes the automated data acquisition and handling system, and, where applicable, the CO_2 continuous emission monitoring system), that significantly affects the ability of the system to measure or record the SO_2 concentration, volumetric gas flow, SO_2 mass emissions, NO_X emission rate, CO_2 concentration, or opacity, or to meet the requirements of § 75.21 or appendix B of this part, the owner or operator shall recertify the continuous emission monitoring system, continuous opacity monitoring system, or component thereof according to the procedures in this paragraph. Examples of changes which require recertification include: replacement of the analytical method, including the analyzer; change in location or orientation of the sampling probe or site; rebuilding of the analyzer or all monitoring system equipment; and replacement of an existing continuous emission monitoring system or continuous opacity monitoring system. In addition, if a continuous emission monitoring system is not operating for more than 2 calendar years, then the owner or operator shall recertify the continuous emission monitoring system. The Administrator may determine whether a replacement, modification or change in a monitoring system significantly affects the ability of the monitoring system to measure or record the SO_2 concentration, volumetric gas flow, SO_2 mass emissions, NO_X emission rate, CO_2 concentration, or opacity. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that significantly changes the flow or concentration profile of monitored emissions, the owner or operator shall recertify the continuous emission monitoring system or component thereof according to the procedures in this paragraph. 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. Recertification is not required prior to use of a non-redundant backup continuous emission monitoring system in cases where all of the following conditions have been met: the non-redundant backup continuous emission monitoring system has been certified at the same sampling location within the previous two calendar years; all components of the non-redundant backup continuous emissions monitoring system have previously been certified; and component monitors of the non-redundant backup continuous emission monitoring system pass a linearity check (for pollutant concentration monitors) or a calibration error test (for flow monitors) prior to their use for monitoring of emissions or flow. In addition, changes resulting from routine or normal corrective maintenance and/or quality assurance activities do not require recertification, nor do software modifications in the automated data acquisition and handling system, where the modification is only for the purpose of generating additional or modified reports for the State Implementation Plan, internal company uses, or for reporting requirements under subpart G of this part.

* * * * *

(g) * * *

(1) * * *

(i) When the optional SO_2 mass emissions estimation procedure in appendix D of this part or the optional NO_X emissions estimation protocol in appendix E of this part is used, the owner or operator shall provide data from a calibration test 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) or 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, as required by appendices D and E of this part (all methods incorporated by reference under § 75.6). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards of Technology (NIST) standards. The designated representative shall document the procedure and the equipment used in the monitoring plan for the unit and in a petition submitted in accordance with § 75.66(c).

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7. Section 75.21 is amended by revising paragraph (a); by adding paragraph (d); and by removing paragraph (f) to read as follows:

§ 75.21 Quality assurance and quality control requirements.

(a) *Continuous emission monitoring systems.* The owner or operator of an affected unit shall operate, calibrate and maintain each continuous emission monitoring system used to report emission data under the Acid Rain Program as follows:

(1) The owner or operator shall operate, calibrate and maintain each primary and redundant backup continuous emission monitoring system according to the quality assurance and quality control procedures in appendix B of this part.

(2) The owner or operator shall ensure that each non-redundant backup continuous emission monitoring system complies with the daily and quarterly quality assurance and quality control procedures in appendix B of this part for each day and quarter that the system is used to report data.

(3) The owner or operator shall perform quality assurance upon a reference method backup monitoring system according to the requirements of Method 2, 6C, 7E, or 3A in appendix A of part 60 of this chapter (supplemented, as necessary, by guidance from the Administrator), instead of the procedures specified in appendix B of this part.

(4) When a unit combusts only natural gas or gaseous fuel with a sulfur content no greater than natural gas and SO_2 emissions are determined in accordance with §§ 75.11(e)(1) or (e)(2), 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 of this part on any day or in any calendar quarter in which only natural gas (or gaseous fuel with a sulfur content no greater than 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 sulfur content no greater than 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 until a subsequent test of the same type has been successfully completed.

(5) For a unit with an SO_2 continuous monitoring system, in which natural gas (or gaseous fuel with a sulfur content no greater than 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 or operator shall perform the relative accuracy test audits of the SO_2 monitoring system (as required by section 6.5 in appendix A of this part and section 2.3.1 in appendix B of 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 a unit with an SO_2 monitoring system burns only fuel(s) with a sulfur content no greater than that of natural gas and never combusts other fuel(s) with a sulfur content greater than natural gas, the SO_2 monitoring system is exempted from the relative accuracy test audit requirements in appendices A and B of this part.

(7) In determining the deadline for the next semiannual or annual relative accuracy test audit of an SO_2 monitoring system, any calendar quarter during which a unit combusts only fuel(s) with a sulfur content no greater than natural gas shall be excluded in determining the calendar quarter, bypass operating quarter, or unit operating quarter when the next relative accuracy test audit must be performed for the SO_2 monitoring system. If, however, as a result of such exclusion of calendar quarters, eight calendar quarters elapse after a relative accuracy test audit, without a subsequent relative accuracy test audit of an SO_2 monitoring system having been performed, the owner or operator shall ensure that a relative accuracy test audit is performed in the next calendar quarter in which a fuel with a sulfur content greater than natural gas is burned in the unit.

(8) The owner or operator who, in accordance with § 75.11(e)(1), uses a certified flow monitor and a certified diluent monitor and Equation F–23 in appendix F of this part to calculate SO_2 emissions during hours in which a unit combusts only pipeline natural gas,

shall meet all quality control and quality assurance requirements in appendix B of this part for the flow monitor and the diluent monitor.

* * * * *

(d) *Notification for periodic relative accuracy test audits.* The owner or operator or the designated representative shall submit a written notice of the dates of relative accuracy testing as specified in § 75.61.

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8. Section 75.30 is amended by revising paragraph (d) to read as follows:

§ 75.30 General provisions.

* * * * *

(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 sulfur content no greater than 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 of this part to determine SO_2 mass emissions pursuant to § 75.11(e)(1), the owner or operator shall, for the purposes of reporting heat input data under § 75.54(b)(5) and for the calculation of SO_2 mass emissions using Equation F–23 in section 7 of appendix F of 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 sulfur content no greater than natural gas (i.e., $\leq$ 20 gr/100 scf) and the owner or operator uses the gas sampling and analysis and fuel flow procedures in appendix D of this part, to determine SO_2 mass emissions pursuant to § 75.11(e)(2), the owner or operator shall substitute for missing sulfur content, gross calorific value and fuel flow meter data using the missing data procedures in appendix D of this part and shall also, for the purposes of reporting heat input data under § 75.54(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 sulfur content no greater than that 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 through 75.33 only, all hours during which the unit combusts only natural gas, or a gaseous fuel with a sulfur content no greater than 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 sulfur content no greater than 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.

* * * * *

9. Section 75.32 is amended by revising paragraph (a)(3) and by removing paragraph (a)(4) to read as follows:

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

(a) * * *

(3) The owner or operator shall include all unit operating hours, and all monitor operating hours for which quality-assured data were recorded by a certified primary monitor; a certified redundant or non-redundant backup monitor or a reference method for that unit; or by an approved alternative monitoring system under subpart E of this part when calculating percent monitor data availability using Equation 8 or 9. No hours from more than three years (26,280 clock hours) earlier shall be used in Equation 9. For a unit that has accumulated less than 8,760 unit operating hours in the previous three years (26,280 clock hours), replace the words ''during previous 8,760 unit operating hours'' in Equation 9 with ''in the previous three years'' and replace ''8,760'' with ''total unit operating hours in the previous three years.'' 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 sulfur content no greater than natural gas) from calculations of percent monitor data availability for SO_2 pollutant concentration monitors, as provided in § 75.30(d).

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10. Section 75.34 is amended by revising paragraphs (a), (b) introductory text, (b)(1), (c) introductory text, and (d) to read as follows:

§ 75.34 Units with add-on emission controls.

(a) The owner or operator of an affected unit equipped with add-on SO_2 and/or NO_X emission controls shall use one of the following options for each hour in which quality-assured data from the outlet SO_2 and/or NO_X monitoring system(s) are not obtained:

(1) The owner or operator may use the missing data substitution procedures as specified for all affected units in §§ 75.31 through 75.33 to substitute data for each hour in which the add-on emission controls are operating within the proper parametric ranges specified in the quality assurance/quality control program for the unit, required by section 1 in appendix B of this part. The designated representative shall document in the quality assurance/quality control program the ranges of the add-on emission control operating parameters that indicate proper operation of the controls. The owner or operator shall, for each missing data period, record data to verify the proper operation of the SO_2 or NO_X add-on emission controls during each hour, as described in paragraph (d) of this section. In addition, under § 75.64(c), the designated representative shall submit a certified verification of the proper operation of the SO_2 or NO_X add-on emission control for each missing data period at the end of each quarter.

(2) The designated representative may petition the Administrator under § 75.66 to replace the maximum recorded value in the last 720 quality-assured monitor operating hours with a value corresponding to the maximum controlled emission rate (an emission rate recorded when the add-on emission controls were operating) recorded during the last 720 quality-assured monitor operating hours. For such a petition, the designated representative must demonstrate that the following conditions are met: the monitor data availability, calculated in accordance with § 75.32, for the affected unit is below 90.0 percent and parametric data establish that the add-on emission controls were operating properly (i.e., within the range of operating parameters provided in the quality assurance/

quality control program) during the time period under petition.

(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 of this part. The owner or operator shall record the data required in appendix C of this part, pursuant to § 75.55(b).

(b) For an affected unit equipped with add-on SO_2 emission controls, the designated representative may petition the Administrator to approve a parametric monitoring procedure, as described in appendix C of this part, for calculating substitute SO_2 concentration data for missing data periods. The owner or operator shall use the procedures in §§ 75.31, 75.33, or 75.34(a) for providing substitute data for missing SO_2 concentration data unless a parametric monitoring procedure has been approved by the Administrator.

(1) Where the monitor data availability is 90.0 percent or more for an outlet SO_2 pollutant concentration monitor, the owner or operator may calculate substitute data using an approved parametric monitoring procedure.

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(c) For an affected unit with NO_X add-on emission controls, the designated representative may petition the Administrator to approve a parametric monitoring procedure, as described in appendix C of this part, in order to calculate substitute NO_X emission rate data for missing data periods. The owner or operator shall use the procedures in §§ 75.31 or 75.33 for providing substitute data for missing NO_X emission rate data prior to receiving the Administrator's approval for a parametric monitoring procedure.

* * * * *

(d) The owner or operator shall keep records of information as described in subpart F of this part to verify the proper operation of the SO_2 or NO_X emission controls during all periods of SO_2 or NO_X emission missing data. The owner or operator shall provide these records to the Administrator or to the EPA Regional Office upon request. Whenever such data are not provided or such data do not demonstrate that proper operation of the SO_2 or NO_X add-on emission controls has been maintained in accordance with the range of add-on emission control operating parameters reported in the quality assurance/quality control program for the unit, the owner or operator shall substitute the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter, to report the NO_X emission rate, and either the maximum hourly SO_2 concentration recorded by the inlet monitor during the previous 720 quality-assured monitor operating hours, if available, or the maximum potential concentration for SO_2, as defined by section 2.1.1.1. of appendix A of this part, to report SO_2 concentration for each hour of missing data until information demonstrating proper operation of the SO_2 or NO_X emission controls is available.

11. Section 75.53 is amended by revising the introductory text of paragraph (d) and removing paragraph (d)(4) to read as follows:

§ 75.53 Monitoring plan.

* * * * *

(d) *Contents of monitoring plan for specific situations.* The following additional information shall be included in the monitoring plan for gas-fired or oil-fired units:

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12. Section 75.55 is amended by revising paragraphs (b)(3), introductory, (b)(3)(i), (b)(3)(ii), and (e) to read as follows:

§ 75.55 General recordkeeping provisions for specific situations.

* * * * *

(b) * * *

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

* * * * *

(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 sulfur content no greater than 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), 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 sulfur content no greater than natural gas is combusted in the unit. If the unit sometimes burns only natural gas (or gaseous fuel with a sulfur content no greater than 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 type of fuel was combusted in the unit during each missing data period. This recordkeeping requirement does not apply to an affected unit that burns natural gas (or gaseous fuel with a sulfur content no greater than natural gas) exclusively, nor does it apply to a unit that burns such gaseous fuel(s) only during unit startup.

* * * * *

13. Section 75.56 is amended by revising paragraph (c); and by adding paragraph (d) to read as follows:

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

* * * * *

(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 of 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) The owner or operator shall meet the requirements of paragraphs (a) and (b) of this section on and after January 1, 1996. The owner or operator shall meet the requirements of paragraph (c) of this section on and after January 1, 1998.

14. Section 75.61 is amended by adding paragraph (a)(5) to read as follows:

§ 75.61 Notifications.

* * * * *

(a) * * *

(5) *Periodic relative accuracy test audits.* The owner or operator or designated representative of an affected unit shall submit written notice of the date of periodic relative accuracy testing performed under appendix B of this part no later than 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means acceptable to the respective State agency or office of EPA, and the notice is provided as soon as practicable after the new testing date is known, but no later than twenty-four (24) hours in advance of the new date of testing.

(i) Written notification under paragraph (a) (5) of this section may be provided either by mail or by facsimile. In addition, written notification may be provided by electronic mail, provided that the respective State agency or office of EPA agrees that this is an acceptable form of notification.

(ii) Notwithstanding the notice requirements under paragraph (a)(5) of this section, the owner or operator may elect to repeat a periodic relative accuracy test immediately, without additional notification whenever the owner or operator has determined that a test was failed, or that a second test is necessary in order to attain a reduced relative accuracy test frequency.

(iii) *Waiver from notification requirements.* The Administrator, the appropriate EPA Regional Office, or the applicable State air pollution control agency may issue a waiver from the requirement of paragraph (a)(5) of this section to provide notice to the respective State agency or office of EPA for a unit or a group of units for one or more tests. The Administrator, the appropriate EPA Regional Office, or the applicable State air pollution control agency may also discontinue the waiver and reinstate the requirement of paragraph (a)(5) of this section to provide notice to the respective State agency or office of EPA for future tests for a unit or a group of units. In addition, if an observer from a State agency or EPA is present when a test is rescheduled, the observer may waive all notification requirements under paragraph (a)(5) of this section for the rescheduled test.

* * * * *

15. Section 75.66 is amended by revising paragraph (f)(2) to read as follows:

§ 75.66 Petitions to the Administrator.

* * * * *

(f) * * *

(2) Data demonstrating that the add-on emission controls were operating properly during the time period under petition (i.e., operating parameters were within the ranges specified for proper operation of the add-on emission controls in the quality assurance/quality control program for the unit);

* * * * *

16. Appendix A to part 75 is amended as follows:

a. by removing sections 6.3.1, 6.3.2 and 6.4.1;

b. by revising section 6.4;

c. by redesignating sections 6.3.3 and 6.3.4 as sections 6.3.1 and 6.3.2 and revising newly designated section 6.3.1; and

d. by adding figure 6 (with notes A through F) after figure 5 at the end of the appendix.

Appendix A to Part 75—Specifications and Test Procedures

* * * * *

6.3 7-day Calibration Error Test

6.3.1 Pollutant Concentration Monitor and CO_2 or O_2 Monitor 7-day Calibration Error Test

Measure the calibration error of each pollutant concentration monitor and CO_2 or O_2 monitor while the unit is operating 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.

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 in a way 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 two concentrations: (1) zero-level and (2) high-level, 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 NIST traceable reference material, standard reference material, NIST/EPA-approved certified reference material, research gas material, Protocol 1 calibration gases certified by the vendor to be within 2 percent of the label value or zero air material for the zero level only.

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 audit 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 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.

* * * * *

6.4 Cycle Time Test

Perform cycle time tests for each pollutant concentration monitor, and continuous emission monitoring system while the unit is operating, according to the following procedures (see also Figure 6 of this appendix).

Use a zero-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. To determine the upscale elapsed time, inject a zero-level concentration calibration gas into the probe tip (or injection port leading to the calibration cell, for in situ systems with no probe). Record the stable starting gas value and start time, using the data acquisition and handling system (DAHS). Next, allow the monitor to measure the concentration of flue gas emissions until the response stabilizes. Record the stable ending stack emissions value and the end time of the test using the DAHS. Determine the upscale elapsed time as the time it takes for 95.0 percent of the step change to be achieved between the stable starting gas value and the stable ending stack emissions value. Then repeat the procedure, starting by injecting the high-level gas concentration to determine the downscale elapsed time, which is the time it takes for 95.0 percent of the step change to be achieved between the stable starting gas value and the stable ending stack emissions value. End the downscale test by measuring the stable concentration of flue gas emissions. Record the stable starting and ending monitor values, the start and end times, and the downscale elapsed time for the monitor using the DAHS. A stable value is equivalent to a reading with a change of less than 2 percent of the span value for 2 minutes, or a reading with a change of less than 6 percent from the measured average concentration over 6 minutes. (Owners or operators of systems which do not record data in 1-minute or 3-minute intervals may petition the Administrator under § 75.66 for alternative stabilization criteria).

For monitors or monitoring systems that perform a series of operations (such as purge, sample, and analyze), time the injections of the calibration gases so they will produce the longest possible cycle time. Report the slower of the two elapsed times (upscale or downscale) as the cycle time for the analyzer. (See Figure 5 of this appendix.) For the NO_X-diluent continuous emission monitoring system test and SO_2-diluent continuous emission monitoring system test, record and report the longer cycle time of the two component analyzers as the system cycle time.

For time-shared systems, this procedure must be done at all probe locations that will be polled within the same 15-minute period during monitoring system operations. To determine the cycle time for time-shared systems, add together the longest cycle time obtained at each of the probe locations. Report the sum of the longest cycle time at each of the probe locations plus the sum of the time required for all purge cycles (as determined by the continuous emission monitoring system manufacturer) at each of the probe locations as the cycle time for each of the time-shared systems. For monitors with dual ranges, report the test results from on the range giving the longer cycle time. Cycle time test results are acceptable for monitor or monitoring system certification if none of the cycle times exceed 15 minutes.

* * * * *

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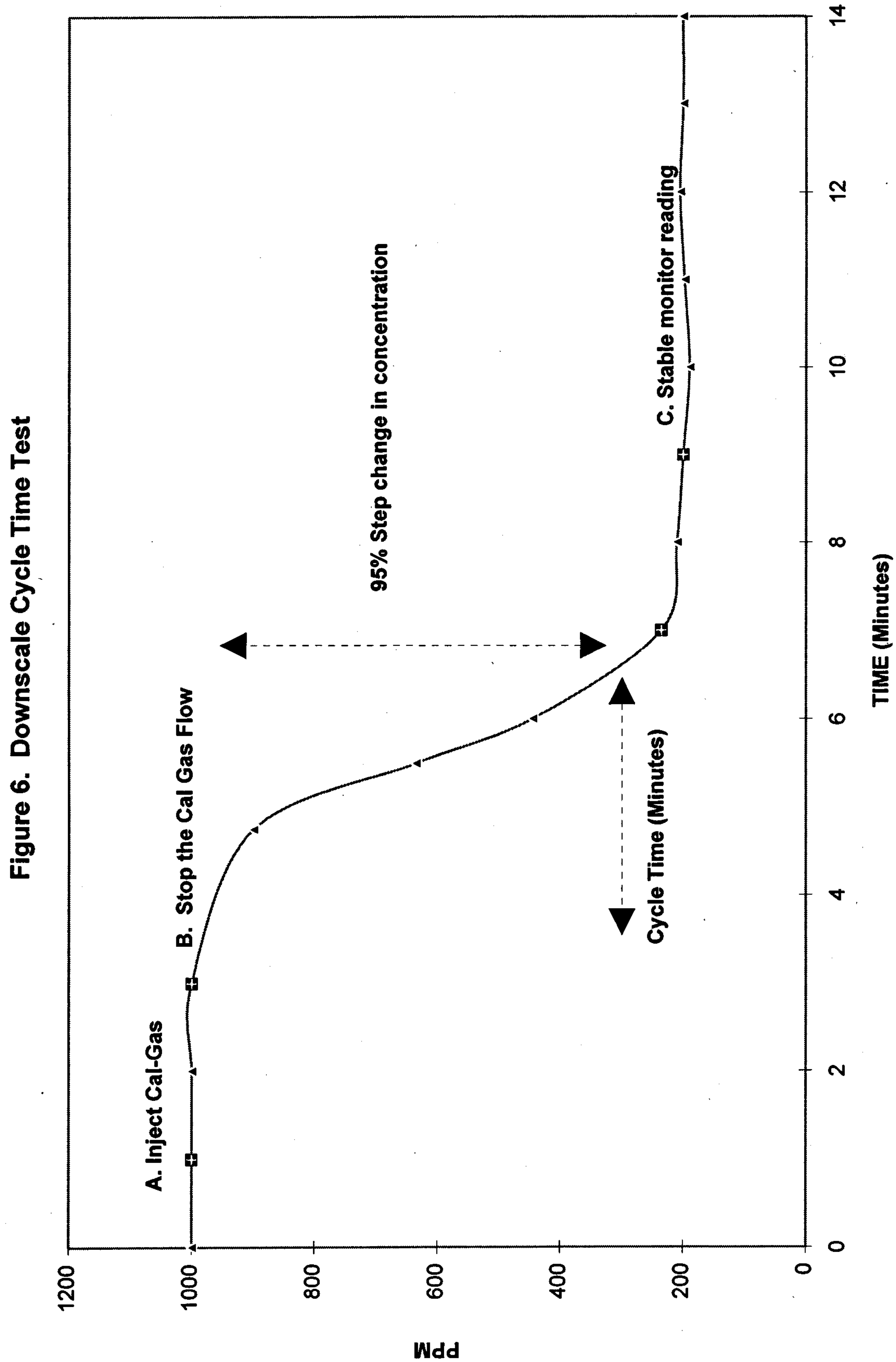

Figure 6. Downscale Cycle Time Test

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A. To determine the downscale cycle time, inject a high level calibration gas into the port leading to the calibration cell or thimble.

B. Allow the analyzer to stabilize. Record the stabilized value. Stop the calibration gas flow and allow the monitor to measure the flue gas emissions until the response stabilizes.

C. Record the stabilized value. A stable reading is achieved when the concentration reading deviates less than 6% from the measured average concentration in 6 minutes or if it deviates less than 2% of the monitor's span value in 2 minutes. (Owners and operators of units that do not record data in 1 minute or 3 minute intervals may petition the Administrator under section 75.66 for alternative stabilization criteria.)

D. Determine the step change. The step change is equal to the difference between the stabilized calibration gas value (Point B) and the final stable value (Point C). Take 95% of the step change value and subtract the result from the stabilized calibration gas value (Point B). Determine the time at which 95% of the step change occurred (Point D).

E. Determine the cycle time. The cycle time is equal to the downscale elapsed time, i.e. the time at which 95% of the step change occurred (point D) minus the time at which the calibration gas flow was stopped (Point B). In this example, cycle time=(6.5 − 4)=2.5 minutes (Report as 3 minutes).

F. To determine the cycle time for the upscale test, inject a zero scale calibration gas into the probe and repeat the procedures described above, except that 95% of the step change in concentration is added to the stabilized calibration gas value. Afterwards, compare the two cycle times achieved for both the upscale and downscale tests. The longer of these two times equals the cycle time for the analyzer.

17. Appendix B to part 75 is amended as follows:

a. by revising sections 2.1 and 2.1.1;

b. by removing sections 2.1.2 and 2.1.7; redesignating section 2.1.3 as section 2.1.2 and revising newly designated section 2.1.2;

c. by redesignating sections 2.1.4 and 2.1.5 as 2.1.3 and 2.1.4, respectively; and

d. by adding new sections 1.6, 2.1.1.1 and 2.1.1.2, 2.1.5, 2.1.5.1, and 2.1.5.2.

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Control Program

*   *   *   *   *

1.6 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), 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 hour of each SO_2 or NO_X missing data period.

*   *   *   *   *

2. Frequency of Testing

*   *   *   *   *

2.1 Daily Assessments

Perform the following daily assessments to quality-assure the hourly data recorded by the monitoring systems during each period of unit operation, or, for a bypass stack or duct, each period in which emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or continuous emission monitoring system completes certification testing.

2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system according to the procedure in section 6.3.1 of appendix A of 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 of this part.

For units with add-on emission controls and dual-span or auto-ranging monitors, and other units that use the maximum expected concentration to determine calibration gas values, perform the daily calibration error tests on each scale that has been used since the previous calibration error test. For example, if the pollutant concentration has not exceeded the low-scale value (based on the maximum expected concentration) since the previous calibration error test, the calibration error test may be performed on the low-scale only. If, however, the concentration has exceeded the low-scale span value for one hour or longer since the previous calibration error test, perform the calibration error test on both the low- and high-scales.

2.1.1.1 On-line Daily Calibration Error Tests. Except as provided in section 2.1.1.2 of this appendix, all daily calibration error tests must be performed while the unit is in operation at normal, stable conditions (i.e. ‘‘on-line’’).

2.1.1.2 Off-line Daily Calibration Error Tests. Daily calibrations may be performed while the unit is not operating (i.e., ‘‘off-line’’) and may be used to validate data for a monitoring system that meets the following conditions:

(1) An initial demonstration test of the monitoring system is successfully completed and the results are reported in the quarterly report required under § 75.64 of this part. The initial demonstration test, hereafter called the ‘‘off-line calibration demonstration’’, consists of an off-line calibration error test followed by an on-line calibration error test. Both the off-line and on-line portions of the off-line calibration demonstration must meet the calibration error performance specification in section 3.1 of appendix A of this part. Upon completion of the off-line portion of the demonstration, the zero and upscale monitor responses may be adjusted, but only toward the true values of the calibration gases or reference signals used to perform the test and only in accordance with the routine calibration adjustment procedures specified in the quality control program required under section 1 of appendix B to this part. Once these adjustments are made, no further adjustments may be made to the monitoring system until after completion of the on-line portion of the off-line calibration demonstration. Within 26 clock hours of the completion hour of the off-line portion of the demonstration, the monitoring system must successfully complete the first attempted calibration error test, i.e., the on-line portion of the demonstration.

(2) For each monitoring system that has passed the off-line calibration demonstration, a successful on-line calibration error test of the monitoring system must be completed no later than 26 unit operating hours after each off-line calibration error test used for data validation.

2.1.2 Daily Flow Interference Check

Perform the daily flow monitor interference checks specified in section 2.2.2.2 of appendix A of this part while the unit is in operation at normal, stable conditions.

*   *   *   *   *

*   *   *   *   *

2.1.5 Quality Assurance of Data With Respect to Daily Assessments

When a monitoring system passes a daily assessment (i.e., daily calibration error test or daily flow interference check), data from that monitoring system are prospectively validated for 26 clock hours (i.e., 24 hours plus a 2-hour grace period) beginning with the hour in which the test is passed, unless another assessment (i.e. a daily calibration error test, an interference check of a flow monitor, a quarterly linearity check, a quarterly leak check, or a relative accuracy test audit) is failed within the 26-hour period.

2.1.5.1 Data Invalidation with Respect to Daily Assessments. The following specific rules apply to the invalidation of data with respect to daily assessments:

(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 2.1.3.2 of this appendix) if the required subsequent daily assessment has not been conducted.

(2) Beginning on January 1, 1999, for a monitoring system that has passed the off-line calibration demonstration, if an on-line daily calibration error test of the same monitoring system is not conducted and passed within 26 unit operating hours of an off-line calibration error test that is used for data validation, then data from that monitoring system are invalid, beginning with the 27th unit operating hour following that off-line calibration error test.

2.1.5.2 Daily Assessment Start-Up Grace Period. For the purpose of quality assuring data with respect to a daily assessment (i.e. a daily calibration error test or a flow interference check), a start-up grace period may apply when a unit begins to operate after a period of non-operation. The start-up grace period for a daily calibration error test is independent of the start-up grace period for a daily flow interference check. To qualify for a start-up grace period for a daily assessment, there are two requirements:

(1) The unit must have resumed operation after being in outage for 1 or more hours (i.e., the unit must be in a start-up condition) as evidenced by a change in unit operating time from zero in one clock hour to an operating time greater than zero in the next clock hour.

(2) For the monitoring system to be used to validate data during the grace period, the previous daily assessment of the same kind must have been passed on-line within 26 clock hours prior to the last hour in which the unit operated before the outage. In addition, the monitoring system must be in-control with respect to quarterly and semi-annual or annual assessments.

If both of the above conditions are met, then a start-up grace period of up to 8 clock hours applies, beginning with the first hour of unit operation following the outage. During the start-up grace period, data generated by the monitoring system are considered quality-assured. For each monitoring system, a start-up grace period for a calibration error test or flow interference check ends when either: (1) a daily assessment of the same kind (i.e., calibration error test or flow interference check) is performed; or (2) 8 clock hours have elapsed (starting with the first hour of unit operation following the outage), whichever occurs first.

* * * * *

18. Appendix D of part 75 is amended by revising section 2.1.5.1 to read as follows:

Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

* * * * *

2.1 Flowmeter Measurements

* * * * *

2.1.5.1 Use the procedures in the following standards for flowmeter calibration or flowmeter 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,’’ or MFC–9M–1988 with December 1989 Errata (‘‘Measurement of Liquid Flow in Closed Conduits by Weighing Method’’) for all other flow meter types (incorporated by reference under § 75.6 of this part). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document other procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit and a petition submitted 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.

* * * * *

19. Appendix F of part 75 is amended by revising section 7 to read as follows:

Appendix F to Part 75—Conversion Procedures

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7. Procedures for SO_2 Mass Emissions at Units With SO_2 Continuous Emission Monitoring Systems During the Combustion of Pipeline Natural Gas

The owner or operator shall use the following equation to calculate hourly SO_2 mass emissions as allowed for units with SO_2 continuous emission monitoring systems if, during the combustion of pipeline natural gas, SO_2 emissions are determined in accordance with § 75.11(e)(1).

$$E_h=(0.0006)\ HI \qquad \text{(Eq. F–23)}$$

Where,

E_h=Hourly SO_2 mass emissions, lb/hr.

0.0006=Default SO_2 emission rate for pipeline natural gas, lb/mmBtu.

HI=Hourly heat input, as determined using the procedures of section 5.2 of this appendix.

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