Estimated Burden Hours Per Response: 5 minutes
Frequency of Response: On occasion
Estimated Total Reporting Burden: 2,166 hours
Clearance Officer: Lois K. Holland (202) 622–1563, Departmental Offices, Room 3171, Treasury Annex, 1500 Pennsylvania Avenue, NW., Washington, DC 20220
OMB Reviewer: Milo Sunderhauf (202) 395–6880, Office of Management and Budget, Room 3001, New Executive Office Building, Washington, DC 20503

Lois K. Holland,
Departmental Reports Management Officer.
[FR Doc. 93–530 Filed 1–8–93; 8:45 am]
BILLING CODE 4810–25–M

Customs Service

[T.D. 93–4]

Revocation of Individual Broker License No. 4063; Kenneth A. Anderson, Jr.

AGENCY: U.S. Customs Service, Department of the Treasury.
ACTION: General notice.

SUMMARY: Notice is hereby given that the Secretary of the Treasury, pursuant to section 641, Tariff Act of 1930, as amended (19 U.S.C. 1641), and part 111.74 of the Customs Regulations, as amended (19 CFR 111.74), revoked the individual broker license no. 4063 issued to Kenneth A. Anderson, Jr. This action having been upheld by the United States Court of International Trade (Court No. 90–11–00617); and, under appeal, by the Court of Appeals for the Federal Circuit (Appeal No. 92–1444) is effective as of November 28, 1992.

Dated: January 5, 1993.

Thomas P. Banner,
Acting Deputy Director, Office of Trade Operations.
[FR Doc. 93–469 Filed 1–8–93; 8:45 am]
BILLING CODE 4820–02–M

Office of Thrift Supervision

[AC–1: OTS No. 3404]

First Federal Savings Bank of Maryville, Maryville, TN; Approval of Conversion Application

Notice is hereby given that on December 28, 1992, the Deputy Assistant Director, Corporate Activities Division, Office of Thrift Supervision, or her designee, acting pursuant to delegated authority, approved the application of First Federal Savings Bank of Maryville, Maryville, Tennessee for permission to convert to the stock form of organization. Copies of the application are available for inspection at the Information Services Division, Office of Thrift Supervision, 1776 G Street, NW., Washington, DC 20552, and the Central Regional Office, Office of Thrift Supervision, 111 East Wacker Drive, Suite 800, Chicago, Illinois 60601.

Dated: January 6, 1993.

By the Office of Thrift Supervision.

Nadine Y. Washington,
Corporate Secretary.
[FR Doc. 92–552 Filed 1–8–92; 8:45 am]
BILLING CODE 6720–01–M

Sunshine Act Meetings

Federal Register
Vol. 58, No. 6
Monday, January 11, 1993

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice

(January 6, 1993)

The following notice of meeting is published pursuant to Section 3(a) of the Government in the Sunshine Act (Pub. L. No. 94–409), 5 U.S.C. 552b:

DATE AND TIME: January 13, 1993, 10 a.m.

PLACE: 825 North Capitol Street NE., Room 9306, Washington, DC 20426.

STATUS: Open.

MATTERS TO BE CONSIDERED: Agenda.

*Note.—Items listed on the agenda may be deleted without further notice.

CONTACT PERSON FOR MORE INFORMATION: Lois D. Cashell, Secretary, Telephone (202) 208–0400. For a recording listing items stricken from or added to the meeting, call (202) 208–1627.

This is a list of matters to be considered by the Commission. It does not include a listing of all papers relevant to the items on the agenda; however, all public documents may be examined in the Reference and Information Center.

Consent Agenda—Hydro, 971st Meeting—January 13, 1993, Regular Meeting (10:00 a.m.)

CAH–1.
Project No. 8835–017, Dewey B. Smith
CAH–2.
Project No. 2614–018, City of Hamilton, Ohio
CAH–3.
Project Nos. 1953–006 and 008, Consolidated Water Power Company
CAH–4.
Project No. 1957–004, Wisconsin Public Service Corporation
CAH–5.
Project No. 11080–001, Eagle Mountain Energy Company
CAH–6.
Omitted
CAH–7.
Project No. 1417–042, Central Nebraska Public Power and Irrigation District
Project No. 1835–080, Nebraska Public Power District
CAH–8.
Project No. 7270–012, Northern Wasco County People's Utility District
CAH–9.
Project Nos. 2110–002, 2192–005, 2256–002 and 2590–002, Consolidated Water Power Company
CAH–10.
Project No. 2523–002, Wisconsin Electric Power Company
CAH–11.
Project Nos. 9885–027, 032 and 033, Marysville Hydro Partners

Consent Electric Agenda

CAE–1.
Docket No. ER92–533–000, Louisville Gas and Electric Company
CAE–2.
Docket No. EL92–24–001, The Algoma Group v. Wisconsin Public Service Corporation
CAE–3.
Docket No. RM92–3–000, Annual Update of Commission Filing Fees
CAE–4.
Docket No. EL92–22–000, City of Lebanon, Ohio v. Cincinnati Gas & Electric Company
CAE–5.
Docket No. EL92–42–000, UNITIL Power Corporation v. Public Service Company of New Hampshire and Northeast Utilities
CAE–6.
Omitted
CAE–7.
Docket No. EL91–36–000, Northeast Utilities Service Company
CAE–8.
Docket No. ER92–809–001, Illinois Power Company
CAE–9.
Docket No. EC88–2–009, Utah Power & Light Company, PacifiCorp, and PC/UP&L Merging Corporation

Consent Miscellaneous

CAM–1.
Docket No. RM93–6–000, Repeal of Certain Standards of Conduct Provisions in Part 3c
CAM–2.
(A) Docket No. RO86–13–000, Merit Petroleum, Inc.
(B) Docket No. RO87–6–000, Petrade International, Inc.
(C) Docket No. RO88–11–000, Port Petroleum, Inc., Morris M. James, T. Michael Howell, and C. Geogory Crafts
(D) Docket No. RO88–1–000, Leonard O. Rice d/b/a Rice Oil Company and Rice-Lindquist, Inc.

Consent Oil and Gas Agenda

CAG–1.
Omitted
CAG–2.
Docket Nos. TM93–2–24–000, 001 and 002, Equitrans, Inc.
CAG–3.
Docket Nos. RP93–31–000 and CP88–328–000, Transcontinental Gas Pipe Line Corporation
CAG–4.
Omitted
CAG–5.
Docket No. TA92–1–28–008, Panhandle Eastern Pipe Line Company
CAG–6.
Docket Nos. RP92–215–000 and 001, Columbia Gas Transmission Corporation
CAG–7.
Docket Nos. RP88–228–039, 040, CP87–115–008, 009, RP88–249–009, 010, RP86–119–027, 030, RP92–206–001, RP88–191–030, RP89–30–006, RP90–122–009, RP91–167–008, RP89–29–013, RP89–149–009, RP89–242–008, CP89–470–006, TA84–2–9–022, TA85–1–9–014, TA89–1–9–004, TA90–1–9–008, TA91–1–9–006, RP91–16–004, 005, CP87–103–011, CP91–3135–005, RP91–210–013 and RP92–220–003, Tennessee Gas Pipeline Company
CAG–8.
Docket No. RP92–132–008, Tennessee Gas Pipeline Company
CAG–9.
Docket No. RP92–132–009, Tennessee Gas Pipeline Company
CAG–10.
Docket No. RP92–165–007, Trunkline Gas Company
CAG–11.
Docket Nos. RP93–4–001 and RS92–43–001, Mississippi River Transmission Corporation
CAG–12.
Docket No. RP89–185–007, Panhandle Eastern Pipe Line Company
CAG–13.
Docket Nos. RP87–30–000 (Phase II) and RP90–69–000 (Phase A), Colorado Interstate Gas Company
CAG–14.
Docket No. RP91–143–000, Great Lakes Gas Transmission Limited Partnership
CAG–15.
Docket No. RM87–17–004, Natural Gas Data Collection System
CAG–16.
Omitted
CAG–17.
Docket No. GP91–8–001, Jack J. Grynberg, Individually and as General Partner for the Greater Green River Basin Drilling Program: 72–73 v. Rocky Mountain Natural Gas Company, a division of KN Energy, Inc.
Docket No. GP91–10–001, Rocky Mountain Natural Gas Company v. Jack J. Grynberg, Individually and as General Partner for the Greater Green River Basin Drilling Program: 72–73
CAG–18.
Docket No. GP89–54–000, Amoco Production Company
CAG–19.

Docket No. RS92–87–002, Transwestern Pipeline Company

CAG–20.
Docket Nos. RP93–5–002 and RS92–69–001, Northwest Pipeline Corporation

CAG–21.
Docket Nos. RS92–60–005 and RP92–214–003, El Paso Natural Gas Company

CAG–22.
Docket Nos. CP93–57–000, RS92–82–000 and CP92–189–001, Superior Offshore Pipeline Company
Docket No. CP93–47–000, United Gas Pipe Line Company
Docket No. CP76–304–000, Transcontinental Gas Pipe Line Corporation

CAG–23.
Docket No. CP92–504–001, Arkla Energy Resources, a Division of Arkla, Inc. and Arkla Energy Resources Company

CAG–24.
Docket No. CP92–498–001, Trunkline Gas Company

CAG–25.
Docket No. CP90–2155–001, Southern Natural Gas Company

CAG–26.
Docket No. CP90–1249–001, Colorado Interstate Gas Company

CAG–27.
Docket No. CP92–441–001, National Fuel Gas Supply Corporation and Tennessee Gas Pipeline Company

CAG–28.
Omitted

CAG–29.
Docket No. CP92–472–001, Equitrans, Inc.

CAG–30.
Omitted

CAG–31.
(A) Docket Nos. CP89–800–000 and 001, Panhandle Eastern Pipe Line Company
(B) Docket No. CP92–190–000, Panhandle Eastern Pipe Line Company
Docket No. CP92–203–000, KN Wattenburgh Transmission Limited Liability Company
Docket No. CP92–208–000, KN Front Range Gathering Company

CAG–32.
Omitted

CAG–33.
Omitted

CAG–34.
Docket No. CP92–351–000, Williams Natural Gas Company
Docket No. CP92–416–000, Trident NGL, Inc. and Oryx Energy Company

CAG–35.
Docket No. CP89–2165–002, Algonquin Gas Transmission Company

CAG–36.
Docket No. RM90–7–003, Revisions to Regulations Governing Transportation under Section 311 of the Natural Gas Policy Act of 1978 and Blanket Transportation Certificates
Docket Nos. CP93–11–000 and CP93–83–000, El Paso Natural Gas Company

CAG–37.
Docket Nos. CP92–44–000 and 001, El Paso Natural Gas Company

CAG–38.
Docket No. CP92–273–000, West Texas Gas, Inc.

CAG–39.
Docket No. CP92–592–000, United Gas Pipe Line Company

CAG–40.
Docket No. CP91–2904–000, Mississippi River Transmission Corporation

CAG–41.
Docket Nos. RP88–259–060, 059, CP89–1227–000, RP90–124–000, RP90–161–000, RP92–228–000 and RP92–1–008, Northern Natural Gas Company

CAG–42.
Docket Nos. RP91–187–007, CP91–2448–000 and FA91–23–001, Florida Gas Transmission Company

Hydro Agenda

H–1.
Reserved

Electric Agenda

E–1.
Docket No. ER92–280–000, Public Service Electric and Gas Company. Order on transmission rate filing.

E–2.
Docket Nos. ER92–317–001 and ER92–456–001, Public Service Company of Colorado. Order on rehearing regarding transmission rate filing.

E–3.
Docket Nos. EC92–21–000 and ER92–806–000, Entergy Services, Inc. and Gulf States Utilities Company. Order on rate filing and request for merger authorization.

E–4.
Omitted

Miscellaneous Agenda

M–1.
Reserved

Oil and Gas Agenda

I. Pipeline Rate Matters

PR–1.
(A) Docket No. RP91–143–005, Great Lakes Gas Transmission Limited Partnership. Order on rehearing.
(B) Docket Nos. RP89–186–008 and RP90–20–005, Great Lakes Gas Transmission Limited Partnership. Order on rehearing.

II. Restructuring Matters

RS–1.
Docket No. RS92–11–000, Texas Eastern Transmission Corporation. Order on Order No. 636 compliance filing.

III. Pipeline Certificate Matters

PC–1.
Docket Nos. CP92–184–000 and 001, Texas Eastern Transmission Corporation
Docket Nos. CP92–185–000 and 001, Algonquin Gas Transmission Company. Application to construct facilities and to provide firm transportation for six shippers.

PC–2.
Docket Nos. CP91–732–003 and CP88–332–024, Indicated Shippers v. El Paso Natural Gas Company. Order on rehearing.

PC–3.
Docket No. CP80–34–009, Panhandle Eastern Pipe Line Company
Docket No. CP80–35–009, Colorado Interstate Gas Company. Application to amend existing exchange/transportation/sales agreement.

PC–4.
Docket Nos. CP92–182–000, 001 and 002, Florida Gas Transmission Company
Docket No. CP92–415–000, Transcontinental Gas Pipe Line Corporation and Florida Gas Transmission Company. Application to construct Phase III facilities and application for expansion of Mobile Bay facilities.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–677 Filed 1–7–93; 2:50 pm]

BILLING CODE 6717–01–M

federal register

Monday
January 11, 1993

Part II

Environmental Protection Agency

40 CFR Part 72, et al.
Acid Rain Program; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72, 73, 75, 77 and 78
[FRL–4543–5]

Acid Rain Program: General Provisions and Permits, Allowance System, Continuous Emissions Monitoring, Excess Emissions and Administrative Appeals

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Title IV of the Clean Air Act (the Act), as amended November 15, 1990, requires the Environmental Protection Agency (EPA or Agency) to establish an Acid Rain Program to reduce the adverse effects of acidic deposition. To implement this statutory mandate, the Acid Rain Program requirements will be codified in seven regulations. This action delineates all or portions of five final regulations that were initially proposed December 3, 1991: General Provisions and Permits; the Allowance System; Continuous Emissions Monitoring; Excess Emissions Penalties; and Administrative Appeals. (The administrative appeals procedures were originally proposed as a subpart of the permits rule; EPA has decided to remove it from part 72 and place it in a separate part 78.)

In addition to the final rules, this action includes a brief overview of the acid rain problem, summaries of major provisions of the proposed rules, the public's comments on these proposals, and summaries of the major changes that have been made in this final rule.

DATES: These rules become effective February 10, 1993. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of February 10, 1993.

FOR FURTHER INFORMATION CONTACT: Brian McLean, Director, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460. (617) 674–7377.

SUPPLEMENTARY INFORMATION:

I. General Background

The burning of fossil fuels, particularly coal and oil, releases emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) into the atmosphere. Once in the air, SO_2 and NO_x may undergo various chemical reactions, resulting in transformation of the emissions into sulfates, nitrates, sulfuric acid and nitric acid. These compounds can fall to earth near the emission sources of SO_2 and NO_x or be transported hundreds of miles. Referred to as acidic deposition or acid rain, these compounds can be either dry (gases, aerosols, and particles) or wet (precipitation such as rain, fog, or snow). SO_2, and NO_x emissions and their byproducts damage ecosystems and man-made materials, are suspected of posing a threat to human health at current levels, and reduce visibility.

Of the approximately 23 million tons of SO_2 and 19 million tons of NO_x emitted annually from all sources in the United States in 1985, about 16 million tons of SO_2 and 7 million tons of NO_x were emitted by electric utilities. Title IV of the Act requires EPA to establish an Acid Rain Program and a national emissions cap of 8.95 million tons per year on electric utility SO_2 emissions to be implemented in two phases. Phase I (beginning in 1995) requires the 110 highest-emitting utility plants to meet an intermediate SO_2 emissions limitation. By the year 2000 (in which Phase II begins) virtually all other utility units with output capacity greater than 25 megawatts and all new utility units will be required to meet emissions limitations as well. Total annual SO_2 emissions will be reduced by 10 million tons below 1980 levels beginning in the year 2000, a reduction of total SO_2 emissions of approximately 40%. Title IV also requires that certain coal-fired electric utility boilers reduce their emissions of NO_x through installation of low NO_x burner technologies at the same time they are required to comply with the SO_2 limitations. However, these rules do not address the NO_x reduction provisions of the Act.

The centerpiece of the Acid Rain Program is a unique trading system in which allowances (each authorizing the emission of up to one ton of SO_2) are bought and sold at prices determined in a free market. Existing utility sources are allocated allowances based on their historic fuel use and the emissions limitations specified in the Act. Utility units are required to limit SO_2 emissions to the number of allowances they hold, but since allowances are fully transferrable, utilities may meet their emissions control requirements in the most cost-effective manner possible. For instance, a utility may decide to (1) switch to a lower sulfur fuel, (2) install flue gas desulfurization equipment (scrubbers) and bank unused allowances or sell them to other utilities/individuals, (3) forego emissions reductions and buy additional allowances (if necessary) or (4) implement energy efficiency measures at the plant or by encouraging customers to undertake them. Other options and combinations of options are possible, providing an unusually high degree of flexibility for affected sources to comply with the law. The procedures for transferring and tracking allowances are codified in 40 CFR part 73.

In order to operate, each affected source must apply for a permit in which the source certifies that it will hold a sufficient number of allowances to cover its SO_2 emissions, and specifies the source's planned method of compliance. The permit regulation is codified in 40 CFR part 72.

In order to ensure that source compliance results in achieving nationally mandated reductions in SO_2 and NO_x emissions, each affected source must install a system to continuously monitor the emissions and to collect, record, and report emissions data. The continuous emissions monitoring rule is codified in 40 CFR part 75.

If an affected unit exceeds its emissions limitation for either SO_2 or NO_x, the Act requires the affected source to pay penalties and, for SO_2, to submit a plan detailing how the excess SO_2 emissions will be offset and when. These requirements act as a strong incentive for compliance with the mandated emissions reductions of the Acid Rain Program. Excess emissions penalty requirements are codified in 40 CFR part 77.

Finally, should there be disputes over decisions by the Administrator regarding any aspect of the Acid Rain Program, administrative appeals procedures are defined in 40 CFR part 78.

II. Acid Rain Rulemaking Overview

Prior to the publication of the proposed acid rain regulations, EPA solicited comments and ideas from many individuals and organizations that would be affected by such rules. The Acid Rain Advisory Committee (ARAC) was formed for that purpose, and included 44 members representing various stakeholder groups, including utilities, emissions control equipment vendors, State Public Utility Commissioners, academicians, coal companies, State air pollution control agencies, labor, and environmental groups. In addition to the Committee members, hundreds of people attended the six ARAC public meetings and participated in varying degrees in the discussions. Input from these stakeholders and others was extremely helpful in drafting the proposed acid rain rules.

To date, the Agency has proposed three rulemaking packages pursuant to title IV of the Act and finalized one. The first, proposed on May 23, 1991 and finalized December 17, 1991, was

subpart E of 40 CFR part 73 which governs the auction and sale of allowances under the Acid Rain Program. Recently, on July 7, 1992, subparts B and G of 40 CFR part 73 were proposed for public comment. These subparts address the allocation of allowances to electric utilities and small diesel refineries.

The most extensive of the acid rain proposals (hereafter referred to as the "core rules") were proposed in the Federal Register on December 3, 1991. That proposal addressed the acid rain permitting procedures for electric utilities, including administrative appeals (part 72); the operation of the allowance system, including the conservation and renewable energy reserve (subparts A, C, D, and F of part 73); installation and operation of continuous emission monitors (part 75); and penalty procedures if emissions exceed allowances held or emissions limitations (part 77). The core rules are finalized in today's rulemaking.

Between January 6 and 10, 1992, EPA conducted public hearings in Washington, DC, Chicago, and San Francisco on the core rules. Testimony was given by 33 individuals, representing industry, State regulatory organizations, and environmental groups. A full record of both written and oral comment is available in the EPA docket on this rulemaking.

During the public comment period, which closed on February 12, 1992, the Agency received 3249 letters, documents, and telephone communications from a wide variety of interested parties. The general public submitted 2576 letters; private industry, 434; local governments, 131; state agencies and governors, 42; Congress, 32; and environmental groups, 31. These communications contained over 7800 individual comments focused on over 850 major and minor issues. Approximately 80% of the comments were focused on 14 major issue areas. These issue areas are addressed in the preamble that follows, along with other issues that received fewer comments but are judged by the Agency to be of sufficient importance to discuss here. All public comments and the Agency's response to each are available at the docket established for this rule at EPA Headquarters, Air Docket, room M–1500, 1st floor, 401 M Street, SW., Washington, DC, 20460, between the hours of 8:30 a.m. and noon, and 1:30 p.m. to 3:30 p.m., Monday through Friday.

Structural Changes to Today's Rules

Although the final rules published in today's notice remain consistent in content and relatively similar in form with those proposed in December 1991, some structural changes have been made to improve the cogency and general readability of the rules. In drafting the final rules, EPA has endeavored to simplify and streamline the text wherever possible; sections have been relocated to improve the flow of information, redundancies eliminated, and many sections rewritten to enhance clarity. Major changes are noted below. More specific structural changes that are unique to each rule are addressed in the preamble section for that rule.

Definitions and Abbreviations

The proposed rules included definitions and abbreviations sections and other general provisions within the body of each part. This resulted in both redundancies and inconsistencies across rules. In response to public comment on this issue, the Agency has placed all definitions, abbreviations, State and Federal authorities, and other general provisions for parts 72–78 in subpart A of part 72.

EPA has also revised a number of term definitions to improve clarity; others whose meanings were analogous to common English usage have been deleted. Some definitions have been removed because they explain terms that were more appropriately delineated in substantive portions of the rules. Composite term definitions that incorporate expressions defined separately have been eliminated, as well as definitions of terms no longer used in the rules.

All of these steps are intended to ease the task of referencing and understanding terms for the reader and ensure that term definitions are now consistent across all rules. Changes made to individual terms based on public comment on the term itself, on issues that impact the term, or new terms and definitions suggested by the public, are discussed in the appropriate section of the preamble.

Opt-ins Provisions

The proposed core rules contained various provisions concerning opt-in sources under section 410 of the Act. Because the Agency is still developing regulations on opt-ins, virtually all provisions and references to opt-ins have been removed in the final rule. These matters will be addressed in upcoming rulemakings.

Appeals Procedures

The proposed core rules included an appeals section in part 72 that applied only to permits. Public comment was specifically solicited to determine if a broader appeals process located in a separate part would enhance the Acid Rain Program core regulations. In response to comments affirming the idea of both a separate and broadened rule to address appeals issues, part 72, subpart H, has been revised and relocated to part 78. This rule now addresses administrative appeals procedures for the entire Acid Rain Program.

Forms

In the proposed core rules, EPA introduced the concept of using standard forms to submit required applications and to report data and information for all parts of the Acid Rain Program. EPA proposed a number of forms for the regulated community to use in submittals regarding allowance transactions, compliance plans, and continuous emission monitors. The primary rationale for including these forms in the proposal was to solicit public comment on the overall forms approach to information transfer and to gather opinion on specific data elements requested on the forms. During the public comment period, EPA also held a special public meeting regarding these forms to obtain additional feedback.

The Agency received many public comments supporting the concept of standard form utilization; none received were opposed to the recommendation. Commenters indicated that the forms and instructions were generally sound as proposed, but numerous specific recommendations were offered suggesting how forms and instructions could be improved to eliminate redundancy and increase clarity and consistency. Some commenters stated that improved versions of the forms could be developed as experience is gained through their use. Other commenters questioned the need and usefulness of some data elements, and pointed out that some of the information requests by EPA were "nice-to-know" information or data that the Agency already had in its possession. Comments about data elements were carefully considered as the final substantive sections of today's rule were developed, and are discussed throughout the preamble, as appropriate.

As in December's proposed rule, EPA will itemize in the final rule each of the information and data elements that must be submitted by the owners and operators of an affected source to a permitting authority. While specific forms are not part of the rule, form content will continue to be governed by the rule, which enumerates information requirements.

Commenters and EPA agreed that forms should be removed from the final rule. Not doing so would mean even simple revisions to forms would require rule changes. Since many of these forms will be used throughout the life of the program (and some not utilized until Phase II), the opportunity to easily incorporate the experiences of Phase I permit issuances could significantly benefit implementation of the Acid Rain Program in Phase II. Commenters also stressed that future developments in the field of electronic reporting would more easily be incorporated into the program if forms were not made a part of the rulemaking.

No later than the effective date of this rule, EPA will direct mail packages of standard forms to the owners of all Phase I sources. These packages, with instructions, contain permit forms, monitoring plan forms, and certificates of representation. The certificates of representation will be sent to owners of Phase II sources in the event they wish to certify their representative now. Owners and operators are encouraged to certify as soon as possible in order to fully participate in allowance activities such as auction and sale (see the Discussion of Changes to part 73 for further discussion). The form for an application for a Phase I extension will be sent to those owners who have indicated interest in this compliance option. Any other interested party may obtain the packages of forms and instructions by calling the Acid Rain Hotline.

The preamble that follows outlines the major changes that the proposed rules have undergone since their publication in December 1991 and discusses public comment.

III. Changes to Part 72—Permits

A. Structural Changes

(1) Introduction

EPA received a large number of public comments regarding part 72. The general thrust of many of these was that the proposed rule needed to be simpler and more coherent. In response to these suggestions, EPA has made many revisions to part 72 that are designed to enhance readability and understanding. Because a substantial number of the changes made to this rule are structural and not substantive, the preamble addressing part 72 is divided into two sections, the first summarizing structural changes (streamlining efforts, relocations of sections, deletions, etc.) and the second addressing substantive revisions made to the rule.

(2) General Provisions

The general provisions section in proposed subpart A of part 72, which formerly applied only to the permits rule, has been modified and now applies, for the most part, to the entire Acid Rain Program. Provisions regarding Acid Rain Program definitions, measurements, abbreviations and acronyms, federal authority, state authority, applicability, standard requirements, availability of information, and computation of time that were located in various places in the proposed rule have been consolidated and are now included under this subpart. This modification promotes consistency among the parts of the rule and eliminates unwarranted redundancies.

(3) Definitions

Definitions for the Acid Rain Program have been combined into a single definitions section (§ 72.2) for 40 CFR parts 72, 73, 75, 77, and 78. Some definitions have also been revised to enhance the clarity of the regulatory text. Terms whose definitions did not differ from common English usage (e.g., "calendar year") have been deleted. Conversely, some terms whose definitions include a common meaning but that possess specific connotations regarding the Acid Rain Program have been clarified or removed from the definitions section when the textual context of the rule suffices in conveying the meaning of the term.

A number of definitions have also been eliminated or streamlined because they articulated substantive requirements that were more appropriately denoted in pertinent sections of the rules. Definitions redundant with substantive provisions of the rules have been deleted. The following table lists terms removed from the proposed rules glossary and, where applicable, their location within the text of the final rules.

Acid rain compliance option.	part 72, subpart D
Acid Rain permit application.	part 72, subpart C
Administrative permit amendment.	part 72, subpart H
Alternate authorized account representative.	§ 73.33(d)
Alternate designated representative.	§ 72.22
Applicable requirement of the Act.	Title V, § 70.2
Approved compliance plan.	part 72, subpart D
Automatic permit amendment.	part 72, subpart H
Complete permit application.	§ 72.50
Continuous	§ 72.2 (definitions of CEMS & COMS)
Control unit	Streamlined definition, see also § 72.42
Designated representative.	Streamlined definition, see also § 72.20
Determination of completeness.	§§ 72.61 and 72.72(b)(1)
Dual span system	part 75
Energy conservation measure.	§§ 72.43 and 73.81
Fast track modification.	part 72, subpart H
First-in, first-out accounting basis.	§ 73.35(c)(2)
Load management	§ 73.81(b)(4)
Monitor data availability.	part 75
Non-utility unit	section 402(25) of the Act
Path continuous emission monitoring system.	part 75
Permit modification	part 72, subpart H
Phase I extension unit.	part 72, subpart D
Proposed compliance plan.	part 72, subpart D
Ranking application	§ 72.42
Reduced utilization through energy conservation.	§ 72.43
Reduced utilization through improved unit efficiency.	§ 72.43
Renewable energy generation.	§ 73.81(c)
Renewable energy input.	§ 73.82(a) (12) and (13)
Repowering extension period.	§ 73.44
Sulfur-free generator	§ 72.2 (definition of sulfur-free generation)
Transferee account	part 73, subpart D
Transferror account	part 73, subpart D
Transferror unit account.	part 73, subpart D
Uncontrolled emissions rate.	§ 72.42 and part 75
Use allowances	§ 73.35

The definitions portion of the final rules no longer includes separate definitions for terms that are composites of separately defined terms. For example, the proposed definition for "existing affected unit" was deleted from the final rule since the terms "existing unit" and "affected unit" are defined separately.

One commenter asked that the rules include all statutory definitions applicable to the Program. Although sources should continue to refer to those definitions, § 72.2 lists statutory definitions only for those statutory terms utilized within the rules.

Some rule and terminology revisions have necessitated the redefinition of certain terms. For example, the term "Phase I affected unit" has been revised to read "Phase I unit" throughout the

rules since all Phase I units are affected units.

(4) Deletions and Relocations

A number of the provisions proposed in this subpart have been deleted or moved to other sections. For example, the provisions of the prohibitions (§ 72.8 in the proposed rule) and signatory requirements (§ 72.9 in the proposed rule) sections are, for the most part, now located in § 72.9 (standard requirements), § 72.20 (authorization and responsibilities of the designated representative), and § 72.21 (submissions) of this rule.

(a) Common stacks. Section 72.50 of the proposed rule described special provisions for units with common stacks. Because common stacks are also addressed in part 75 of this chapter, this section was deleted from part 72; requirements that are not redundant have been incorporated into the common stack provisions of part 75. The portion of the preamble covering part 75 discusses public comment on and changes made to the common stack provisions of that rule.

(b) Appendices A & B. Part 72 as proposed contained two lists of affected units: Proposed Appendix A (which listed all Phase I units, had a blank column for their Phase I allocations, and stated the units' 1988 and 1989 SO_2 emissions) and proposed Appendix B (which catalogued Phase II units and allocations). Both have been removed from the rule.

Proposed Appendix A was removed because the list of Phase I units and their allocations has now been promulgated in Table 1 of § 73.10(a) of this chapter with some corrections. In addition, some commenters objected to the figures for 1988 and 1989 SO_2 emissions. Those figures are needed only for those Phase I units involved in a Phase I extension plan and, under the final rule, must be submitted as part of the early ranking application or Phase I extension plan. Comments concerning 1988 and 1989 SO_2 emissions are addressed in section B(5)(c)(ii) of the part 72 preamble, and any remaining comments on proposed Appendix A will be addressed in the rulemaking on subpart B of part 73 of this chapter.

Proposed Appendix B was removed from the final rule because a large number of requests for revisions to proposed Appendix B were received. A more comprehensive and accurate list of existing Phase II units and allocations was proposed, and will be finalized, in Table 2 of subpart B of part 73. All comments on the inclusion or exclusion of specific units in proposed Appendix B will be considered in that rulemaking. See 57 FR 29940, 29965–30024, July 7, 1992.

It should be noted that the final rule contains new appendices that are unrelated to proposed Appendices A and B. Final Appendix A contains the methodology for annualizing emissions limitations. Final Appendix B contains the methodology for converting SO_2 emissions limitations to lb/mmBtu. Final Appendix C contains the methodology for calculating annual tonnage of SO_2 emissions. The methodologies in these final appendices are from the NADB Version 2.1 Technical Support Document.

(c) Reproposals. EPA has determined that further consideration is needed in order to properly draft some provisions originally proposed in the applicability portion of the rule. These provisions concern cogeneration units, new independent power production facilities, and qualifying facilities. The reproposals were included in the proposed rules for allowance allocations and reserves (parts 72 and 73). See 57 FR 29940, 29944–47 July 7, 1992.

The reproposed provisions will be incorporated into this part when promulgated in final form. Public comments received in response to the December 3, 1991 proposal will be addressed in the final rulemaking for these provisions.

(d) Addresses. Addresses for submissions to the Acid Rain Program have been eliminated from the rule so that changes to the addresses will not require a rule change. Appropriate addresses for submissions will be communicated in guidance, forms packages, or separate Federal Register notices as the need arises. EPA headquarters and regional addresses are listed and updated in 40 CFR 1.7.

(5) Combined Subparts and Sections

EPA has removed two subparts of proposed part 72. As mentioned in the overview, subpart H (appeals) has been removed and is now part 78. In addition, the provisions of proposed subparts F and G have, in large part, been combined in the final rule in subpart F. This should not be interpreted as a substantive change since both proposed subparts addressed essentially the same subject, i.e., federal permit issuance procedures in Phase I. All procedures for issuance or denial of a Phase I Acid Rain permit are now located in subpart F of the final rules. Some of the few requirements that were not redundant have been moved to other sections in subpart A or subpart C of the final rule.

Proposed subpart I has been renamed subpart G, but still governs implementation of Phase II of the Acid Rain Program. Subpart G sets out criteria for State operating permit program approval under title V of the Act, which augment or replace criteria set forth at 40 CFR part 70.

Proposed subpart J is now subpart H. In addition to clarifying and streamlining changes, two major substantive changes have been made to proposed subpart J. First, the Agency has eliminated proposed Option 1 under the fast-track modification procedure from the final rule. Second, the Agency has eliminated the requirement that notice be given to interested persons of all administrative amendments that occur under the Acid Rain Program.

Proposed subpart K, renamed subpart I in the final rule, still describes compliance certifications that a designated representative must submit for each affected unit. Because EPA believes that compliance certifications are critical to the smooth operation of the Acid Rain Program, this subpart was reorganized to promote clarity, while some certifications have been eliminated or made more specific. Comments concerning certifications for underutilization, Phase I extensions, and repowering and any major changes to provisions for such certifications are addressed in the respective portions of this preamble dealing with those compliance options.

B. Major Issues

(1) Exemptions (Subpart D)

(a) New units exemption. The proposed rule asked for comment on the possibility of providing an exemption from the Acid Rain Program for small new units. Many commenters requested that the Agency provide some kind of *de minimis* exemption for new units from permitting and all other requirements of title IV. Suggestions included size cutoffs ranging from 5 to 25 MWe, emission tonnage cutoffs such as those for Prevention of Significant Deterioration programs, and exemptions based on boiler or engine type. These recommendations relied heavily on the argument that monitoring costs would be overly burdensome to small utilities and small communities, that emissions from such units are very small and have negligible, if any, effect on the environment, and that the burden on sources and the Agency of permitting all such units would outweigh the benefit of such permitting.

Response: Although the Act does not explicitly provide for a *de minimis* exemption for new units, the Agency agrees with the commenters that such an exemption is appropriate. The

Agency believes that provision of a limited exemption is within its discretion in administering the Act. See *Alabama Power Co.* v. *Costle*, 636 F. 2d 323, 360–61 (D.C. Cir. 1979). Accordingly, EPA has included a provision allowing permitting authorities to grant a *de minimis* exemption in the new § 72.7 of the rule. The Agency reserves the right to reconsider this provision in future years, however, if the total emissions from all exempt units is significantly higher than projected. The rule provides an exemption from most title IV requirements (including the requirement to monitor emissions, hold allowances to cover emissions, and have an Acid Rain permit) for all new utility units that serve one or more generators, the nameplate capacities of which total 25 MWe or less, and that use fuels with a sulfur content less than or equal to 0.05% by weight.

The exemption for these units is based on the Agency's belief that emissions from such units will be *de minimis*. The vast majority of units of 25 MWe or less that use clean fuels are peaking diesel and dual-fuel (natural gas/diesel fuel) internal combustion engines or peaking combustion turbines (primarily natural gas). These units combust low sulfur fuels, such as natural gas and diesel fuel. In the near future, diesel fuel sulfur content requirements for motor vehicles will be reduced to 0.05% sulfur by weight, in accordance with the Act. This fuel will also be available for diesel-fired units and, indeed, may be the only fuel available to them in the future. The sulfur content of natural gas is significantly less than that of diesel fuel. Based on utility projections provided to the Department of Energy and EPA, approximately 170 new units under 25 MWe (including 22 combustion turbines and 148 diesel- or distillate-fired or dual fuel units) are expected to come on line between 1990 and 2000. All of these will likely be peaking units. Based on average heat input for units of this size and type in the NADB and AP42 emission factors, the projected new units will have total annual emissions in the year 2000 of approximately 4 tons of SO_2 and 800 tons of NO_x for the gas-fired units and 134 tons of SO_2 and 1,134 tons of NO_x for the diesel- or distillate-fired units. Because of the higher cost per MWe of operating a unit of this size and type rather than a larger unit burning less expensive fuels, it is extremely unlikely that these units will operate more hours than units of similar size and type have historically. Consequently, EPA has determined that the total SO_2 and NO_x emissions from new units under the exemption will be *de minimis*. EPA made this determination in light of the national cap of 8.95 million tons of SO_2 and the fact that these units have no NO_x limits under title IV and will provide information about their NO_x emission under title I.

This exemption will be of primary benefit to the small peaking diesel and dual fuel units that are operated by many small communities and will also apply to small combustion turbines of the same size, which also have extremely low emission levels. EPA rejected the option of exempting units by engine type, rather than by size and fuel, because a unit may switch to higher sulfur fuels. In addition, larger units will not necessarily have low emission levels. EPA also rejected the idea of exempting units on a case-by-case basis using predicted emissions because of the greater confusion, uncertainty, and regulatory burden that could result.

Although the statutory exemption for existing units that serve only generators with nameplate capacities of 25 MWe or less does not sum the nameplate capacities of all the generators served by the unit and require the total to be 25 MWe or less, the exemption for new units does sum in this manner. The Agency believes that since the new units exemption is based on a determination that emissions from exempt units are *de minimis*, a stricter standard is justified to ensure that the emissions reductions foregone are truly *de minimis*. Also, many of the units are reciprocating engines rather than boilers and therefore do not serve multiple generators. The Agency does not want to encourage future use of multiple generators with such units as a means of avoiding the requirements of title IV and therefore has applied the exemption based on the capacity of individual generators.

To obtain an exemption for a unit, the designated representative must submit a petition stating that the unit meets the criteria for the exemption, that the sulfur content of the fuel deliveries will be tested and information on the sulfur content of the fuel will be kept on site, and that the unit will comply with all requirements of the Acid Rain Program if operations change so that it no longer meets the exemption criteria. In addition, the designated representative must agree to surrender any allowances that the unit would otherwise be allocated under the Act for any years for which the unit will be exempted. Using the same procedures as those for issuing an Acid Rain permit, the permitting authority will then issue a written exemption delineating the exemption and the requirements applicable to the unit. The permitting authority's actions on exemptions are subject to the same right of appeal as actions on permit applications.

Because the Acid Rain Program is based on the calendar year (e.g., the program limits total annual emissions to allowances held at the end of the year), the exemption is effective on a calendar year basis. The exemption takes effect on January 1 of the year after the exemption is approved. An exempt new unit will not have to submit any further information or compliance certifications so long as it meets the exemption criteria. However, the unit must comply with any requirements of the Acid Rain Program that relate to the period during which the unit was not exempted. The exemption will have to be renewed every 5 years, as is an Acid Rain permit. This approach of requiring a renewal submission every 5 years and no annual certifications reduces the burden on the unit and the permitting authority while preserving the permitting authority's ability to keep track of the unit's compliance status.

The exemption will apply unless and until operations at the unit change so that the requirements are no longer met. Should the unit no longer qualify for the exemption, the owners and operators must comply with all requirements of the Acid Rain Program, including the requirement to submit a permit application. Monitoring requirements will take effect as for new units, except that the date on which the unit no longer qualifes for the exemption will be treated as the date of commencement of commercial operation. Although the permitting authority may not be able to issue an Acid Rain permit for such units by the time the unit is required to begin accounting for emissions, the permit application, once deemed complete, will be binding until issuance of a permit.

(b) Retired Units Exemption. The proposed permit rule did not discuss units that retire prior to their compliance deadline. Commenters, however, requested that the Agency provide relief from monitoring and permitting requirements for units that will be retired before the date that they must comply with Acid Rain Program requirements.

Response: The Agency agrees that full permitting is not necessary for retired units under certain circumstances. The Agency has therefore added a new § 72.8, which provides an exemption from some Phase II permitting requirements for any unit that retires

before the issuance, or the renewal, of a Phase II permit. The designated representatives of units that are affected during Phase I and that retire before issuance of a Phase I permit are not exempted from the requirement to submit a Phase I permit application for the unit. A Phase I permit is necessary because, if the unit is underutilized as compared to its baseline (e.g., by being shut down), it must meet the requirement of this part that the underutilization be accounted for. Moreover, a reduced utilization plan may have to be submitted for the unit.

The owners and operators of a unit retired under this section must appoint a designated representative. A designated representative is necessary not only because a petition for an exemption must be submitted, but also because allowances will continue to be allocated to the unit's account in accordance with 40 CFR part 73.

To obtain an exemption, the designated representative must submit a petition by not later than the deadline for submission of a Phase II permit application or, if the unit already has a Phase II permit, for reapplication for an Acid Rain permit. The petition must contain a statement that the unit is or will be retired and a requirement that the designated representative will submit a permit application for the unit before it may recommence operation. As suggested by a commenter, the application deadline is 24 months before the unit recommences operation. This deadline was chosen because it is consistent with the statutory deadline for new units to submit permit applications.

The permitting authority will act on the petition and issue a written exemption for the retired unit using the same procedures as those for issuing an Acid Rain permit. As with the new units exemption, the retired units exemption takes effect January 1 of the year after the exemption is approved. The unit must comply with all requirements of the Acid Rain Program related to the period before it was exempted. No annual submissions or certifications are required so long as the unit qualifies for the exemption, but the exemption will have to be renewed every 5 years. Both the retired units and new units exemptions will be handled by the States, upon approval of their operating permit programs under subpart G of this part and part 70 of this chapter. The costs of issuance and administration of the exemptions are indirect costs of the operating permit program.

This section addresses exemptions from permitting requirements only and does not specify the conditions under which a retired unit may be exempt from monitoring requirements. Those conditions are discussed in the portion of the preamble covering part 75 of this chapter.

(2) Definitions (Subpart A)

(a) *Fuels terminology.* Several comments were submitted concerning the categorization of units by fuel type. Because of the crosscutting nature of these issues, they deserve discussion here.

As many of the commenters noted, the fuels terminology used in the Act and the rules (e.g., "coal-fired", "gas-fired", and "oil-fired", "fossil fuel", "fossil fuel-fired", "coal", "coal-derived", "natural gas", and "fuel oil") affect the applicability of a wide range of Acid Rain Program requirements to affected units. For example, the repowering extension provisions in part 72 of the rules, and the NO_x requirements in section 407 of the Act, apply to "coal-fired" boilers only. Monitoring requirements can also vary depending on whether a unit is classified as "coal-fired", "gas-fired", or "oil-fired." Other provisions, such as a unit's baseline and allowance allocations, are dependent on the "fossil fuel" consumed.

Coal-derived fuel. Numerous commenters asked that the definition of "coal-fired" be revised by deleting the reference to "coal-derived" fuel. They noted that the reference would result in oil- or gas-fired units that burn any amount of coal-derived gas or liquid fuel being treated as "coal-fired" for purposes of the monitoring requirements of the Acid Rain Program. Several commenters noted that coal gas, although not in widespread use, "should burn cleanly" and should be treated as natural gas or methane. Others noted that coal gases and coal liquids are likely to be used in the future as supplemental fuels for gas- and oil-fired units that consume no solid coal. They argue that the regulation of such units as "coal-fired" would inadvertently inhibit advances in important coal-derived fuels technology.

The statute does not define "coal" or "coal-fired", although both terms are used throughout title IV (e.g., definition of "repowering", NO_x applicability). The legislative history, however, makes clear that "coal" fuel includes coal-derived fuels such as washed coal, liquified or gasified coal, and other conversions of coal. For example, the original Administration bill limited repowering to units burning "pulverized coal" (i.e., the conventional method of burning coal). This wording was changed to the more general term "coal-fired", thus implicitly expanding the universe of units potentially eligible for repowering extensions. As evidenced, for example, in the Senate and House committee reports accompanying S. 1630 and H.R. 3030 (Senate Rep. No. 101–228 at 292–93 (1989) and House Rep. No. 101–490 at 363 (1990)), Congress was aware that coal-firing options included a variety of coal-derived fuels.

Although some of the coal derivatives mentioned in the comments are expected to be cleaner than pulverized coal, it is unclear whether the developing technologies will become so standardized as to guarantee the removal of all sulfur components from these new fuel forms. Thus, whether a particular unit burning gasified or liquified coal will or will not emit substantial amounts of SO_2 or NO_x can only be determined with certainty by rigorous continuous emissions monitoring. Sources relying on such fuel in the future will be able to avail themselves of the authority in the Act and the rules to petition for approval of an alternative monitoring system. The state of the technology is not, however, so well established or uniform as to warrant a broad reclassification of such fuels and consequent exceptions to, for example, the monitoring requirements of the Acid Rain Program.

This rule, therefore, preserves the "coal-derived" reference in the definition of "coal-fired." In addition, the terms "coal" and "coal-derived" are defined to add clarity to the rule. The definition of "coal" is based on the definition in 40 CFR 60.41(f), the new source performance standards for coal-fired utility boilers. (The NSPS definition has been revised slightly to cite the correct ASTM and the incorporation by reference section.) The term "coal-derived" is defined in accordance with the legislative history references to include solid coal derivatives, liquified coal, gasified coal, and several other known coal derivatives.

The definition for the term "coal-fired" has also been revised to reflect the different characterizations that will apply under different parts of the Acid Rain Program. Thus, while for purposes of the part 75 monitoring requirements, any unit that burns any amount of coal or coal-derived fuel is "coal-fired", the classification for purposes of other parts of the Acid Rain Program is limited to units burning coal or coal-derived fuel as the primary fuel.

Gas- and oil-fired. One commenter asked that the rules address whether a "gas-fired" unit forced to convert to fuel oil due to a catastrophic interruption or

gas curtailment would be unavoidably held in violation of the monitoring requirements of the rule. The commenter suggested EPA adopt a five-year averaging approach for reclassification to avoid such forced non-compliance. EPA does not believe a specific rule provision is the best way to address such incidents. EPA has adopted an approach based on both the average and the annual figures over three years. In addition, the Agency has ample enforcement discretion in addressing violations caused by catastrophic events beyond the control of a unit.

Several commenters asked that the term "natural gas" (used in the definition of "gas-fired") be defined and that it include: Propane, landfill gas, digester gas, and methane; biomass; and coal-gasification. The final rules include a definition for "natural gas." The Agency, however, rejects the broad interpretation suggested by the commenters since it would not be consistent with the general scientific understanding of the term, nor with the Acid Rain Program's limited applicability to fossil fuel-fired units. The definition of "natural gas" does not, therefore, include landfill gas, digester gas, biomass, or gasified coal.

However, the definition of "gas-fired" was revised to include coal-derived gaseous fuel with a sulfur content no greater than that of natural gas, along with natural gas. Further, the definitions of both "gas-fired" and "oil-fired" have been revised so as not to preclude the use of non-fossil gas and liquid fuels as supplemental fuels for gas-fired and oil-fired units. These changes will allow essentially sulfur-free fuels, such as natural gas, landfill methane, or synthetic propane, but will exclude solid fuels such as wood or municipal waste since such fuels could not be monitored using the excepted methods of appendix D of part 75.

One commenter asked that the words "if any" be added at the end of the definitions for "gas-fired" and "oil-fired", to indicate that units do not have to burn more than one type of fuel. EPA agrees that the change would clarify the definition, and have revised the definitions accordingly.

The rules also include new definitions for "fossil fuel-fired", "fuel oil", "diesel fuel", "primary fuel" or "primary fuel supply".

In addition to the new fuels definitions, the final rules clarify the fuels treatment in the applicability and other provisions of each part of the rule, particularly in so far as a unit might be reclassified due to changes in fuel usage. For example, an existing unit's allowance allocations, based on historical data, will not change if the unit changes from coal-fired to gas-fired; a new unit could not avoid becoming affected by burning something other than a fossil fuel when commencing operation and subsequently switching to a fossil fuel; and the continued availability of a monitoring exception can change should a gas-fired unit begin combusting coal. For greater detail concerning fuel classifications, see the applicable portions of the preamble below.

(b) Utility units. The proposed applicability section identified affected units by referring to units as existing units or new units, or by describing the specific circumstances under which various units serve generators. Several commenters suggested changes to these terms to clarify that only utility units rather than all units are subject to the requirements of the Acid Rain Program.

Response: The term "utility" as defined in the Act specifies that only those units that currently produce, or at various times in the past produced, electricity for sale are utility units. Because the definitions of the terms "existing" and "new" used in the proposal and in the Act both include reference to serving a generator that produces electricity for sale, any unit that is not a utility unit would by definition be excluded by the proposed language. The requested clarification is, therefore, not a substantive change. The rule now includes the term "utility" in conjunction with the terms "existing" and "new" to clarify this point for the reader.

The proposal repeated the statutory definition of the term "utility unit" with a few minor changes. Paragraph (B) of the statutory definition was repeated in the proposal as follows:

> "* * * a unit that was in commercial operation during 1985, but did not, during 1985, serve a generator that produced electricity for sale, shall not be a utility unit for purposes of the Acid Rain Program."

Commenters pointed out that this paragraph of the proposed definition needed clarification because the statutory language, read literally, describes a situation that on its face seems impossible. Since, under section 402(22) of the Act, "commence commercial operation" means "to have begun to generate electricity for sale," it is difficult to see how a unit that did not generate any electricity for sale in 1985 could be considered in commercial operation.

Response: EPA agrees and this paragraph of the definition has, therefore, been clarified in the definitions in today's rule and in the applicability section at § 72.6(b)(3). The Agency has interpreted this latter provision to mean that units that served self-generators in 1985 (i.e., did not generate electricity for sale) are not utility units as long as they continue to serve self-generators (i.e., do not currently generate electricity for sale). Thus, for example, an industrial boiler transmitting steam to a generator to produce electricity for public sale is a utility unit.

(c) Combined Cycle Units. The proposed rules requested comment on the treatment of existing combined cycle units. The proposal included combined cycle units without auxiliary firing in the definition of "simple combustion turbine," causing these units, if they commenced commercial operation before November 15, 1990, to be exempt from the requirements of the Acid Rain Program. Combined cycle units with auxiliary firing were not exempted from the Acid Rain Program in the proposal. Some commenters disagreed with the Agency's position and requested that combined cycle units with auxiliary firing also be exempted, based on the sulfur content of the fuel used. Other commenters supported the Agency's decision.

Response: The Agency has retained the proposed definition of "simple combustion turbine" because it is based on equipment configuration rather than operations. The complex array of operating scenarios under which combined cycle units operate and the relative ease with which operations can be adjusted would make a definition based on operations complex and difficult to implement. This rule, therefore, provides that existing combined cycle turbines that did not use auxiliary firing for commercial power generation in the baseline period (1985–1987) will be treated as simple combustion turbines and are exempt from the requirements of the Acid Rain Program under § 72.6 of the final rule. However, if such a unit after November 15, 1990, utilized firing, EPA will treat that unit as a new unit, subject to the Acid Rain Program. Such a unit will receive no allowances.

(d) Owner or operator. The definition of "owner or operator" has been revised to delete the words "designated representative." The proposed rule interpreted the statutory authorities, responsibilities, and duties of the designated representative as establishing a specific category of the "operator" role. *See* 56 FR 63009 (December 3, 1991). EPA solicited comment on an alternative reading of the statutory language that would

exclude "designated representative" from the definition of "owner or operator" in all cases. *See id.*

The Agency today reaffirms, with some refinements, the statutory interpretation set forth in the preamble. In most cases, the responsibilities of a designated representative will be narrower than those of an operator. Accordingly, based upon comments of the Department of Energy and others, EPA has determined that it would be inappropriate to broadly sweep all designated representatives into the definition of "owner or operator" as provided in the rulemaking proposal.

In some cases, however, the scope of the designated representative's responsibilities, as provided in the final regulations, would in fact be coextensive with those of an operator, and in those cases he or she would still be an operator. As discussed below, one such case is where there is a common designated representative for multiple sources lacking a common owner and operator and participating in a substitution plan. Thus, the definition has been revised to more accurately reflect the varied nature of the role of designated representatives under the Acid Rain Program by effectively providing that a designated representative is an operator only when his or her duties and responsibilities bring him or her within the ambit of that term.

(3) Designated Representative

Title IV of the Clean Air Act requires the owners and operators of each affected source to appoint a designated representative to act as a liaison between the source and EPA on matters concerning the Acid Rain Program.

(a) Designated representative requirements. (i) Universal requirement. In the proposal, EPA required that all sources have a designated representative. Several commenters suggested that EPA eliminate the requirement to have a designated representative where there is only one owner/operator at a source. The commenters argue that a designated representative is not needed in those situations and that the certification requirements are unnecessary and burdensome where there is a single owner/operator.

Response: The Agency disagrees. The designated representative is needed to simplify the Agency's administration of the Acid Rain Program and to ensure the accountability of an owner or operator for actions governed by the program by, *inter alia*, reducing the likelihood of inconsistent submissions by a source. In addition, requiring the source to interact with the Agency exclusively through one designated representative will permit the regulated community to exercise the flexibility in compliance provided under the Acid Rain Program while being assured that EPA will only act on a submission (e.g., an allowance transfer) that is authorized by the source. Thus, no matter how many owners or operators there are at a source, having a single designated representative will benefit both the regulated community and the Agency.

The Agency agrees, however, that one of the certification requirements in the proposed rules was unnecessarily burdensome on sources with single owners and operators. For sources with a single owner and operator, the Agency has eliminated the requirement that the designated representative send written notice of the agreement under which he or she is selected to that owner and operator, who undoubtedly already knows of the agreement. In the final rules, this requirement only applies to sources with multiple owners and operators.

(ii) Designation by source or unit. Several commenters objected to EPA's proposal requiring that each source have only one designated representative. These commenters argued that the language in sections 408(a) and 402(26) of the Act specify that designated representatives should be appointed by unit. The commenters also claimed that units, not sources are accountable for allowance transactions, compliance plans, monitoring reports, and excess emission penalties.

Response: The Agency agrees that most compliance requirements under the Acid Rain Program are imposed on a unit, rather than a source, basis. Nonetheless, the Agency believes that it is appropriate to require one designated representative per source. While units at a source may have some different owners and operators, there is generally one operator who coordinates operations of all the units and whose decisions concerning one unit may have consequences for the operation of other units. The requirement of a single designated representative per source reflects this operating reality. If units at a source were to have different designated representatives, the designated representative of a unit that was out of compliance might claim that the violation was caused by actions at another unit, whose separate designated representative might dispute the claim. The Agency does not believe that it should become involved in these kinds of disputes among units when it assesses compliance with the Acid Rain Program. Therefore, the Agency is requiring that only one designated representative be certified per source. Under this approach, the designated representative will resolve such disputes and will balance the needs of all of the units at the source in order to facilitate compliance by all units whenever possible. This also minimizes the possibility of inconsistent submissions concerning the different units at the source.

(iii) Daily notice requirement. Some commenters objected to the requirement that the designated representative give daily notice for two weeks by publication in a journal of national and general circulation of the agreement by the owners and operators appointing him or her, particularly where there is only a single owner or operator.

Response: Despite these comments, the Agency believes that this requirement is necessary to ensure that all persons that might consider themselves to be owners and operators of a source have the opportunity to learn of the selection of the designated representative. Without public notice, only those persons whom the designated representative believes are owners or operators will get notice of the selection, i.e., through written notice by the designated representative. In order to reduce the potential cost of providing public notice, the Agency modified the rule to require notice for 7 days in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general notice. The provisions concerning the type of publications to be used parallel certain public notice requirements in 40 CFR part 70. The Agency believes that, in light of the significant financial consequences potentially at stake in the selection of a designated representative, this requirement is not unduly burdensome.

(b) Designated representative's responsibilities. Several commenters suggested that EPA allow sources to delegate responsibility for non-allowance related submissions to a responsible official of the company, rather than requiring the designated representative to make all submissions under the Acid Rain Program. The commenters argued that this would provide them with more flexibility and would ensure the integrity of the submissions, by allowing the source to delegate responsibility to someone with personal knowledge about the particular information.

Response: The Agency has attempted to provide sources with maximum flexibility in the Acid Rain Program while ensuring accountability, but does

not agree that submissions may be made by someone other than the designated representative without adversely affecting the integrity of the program. Under section 402(26) of the Act, the designated representative represents the owners and operators in matters under the Acid Rain Program concerning the source, and, as discussed above, there are important reasons for limiting each source to a single representative. Interposing another person between him or her and the Agency would dilute his or her responsibility and in effect create multiple designated representatives for a source. Further, by leaving the responsibility to make submissions with the designated representative, the final rule has the salutary effect of making it clear that the designated representative should be aware of all submissions and, before submitting them, should inquire of persons with personal knowledge of the information in those submissions. Within these parameters the designated representative has flexibility to delegate duties (such as the preparation of submissions). However, under the final rule, the designated representative retains responsibility under the program for, and must sign and certify, all submissions.

(c) Minority ownership issues. (i) Unanimous agreement on selection of designated representative. The Agency received numerous comments on whether the designated representative should be selected by unanimous agreement of all of the owners and operators. Opponents of that approach claim that requiring unanimous consent would result in EPA improperly interfering in existing commercial relationships and contracts. These commenters believe that existing contractual agreements provide the means of resolving potential disagreements among multiple owners of a unit and that it would be counter-productive to require unanimous consent because it would embroil EPA in commercial disputes and, contrary to EPA policy, would supersede existing agreements in some cases.

Other commenters claim that requiring unanimous agreement is necessary to protect minority owners from "tyranny of the majority." Minority owners are concerned that they will be frozen out of the choice of the designated representative, who will then have control over allowances that belong in part to the minority owners and who will exercise this control in a manner adverse to the interests of the minority owners. Minority owners are also concerned that the designated representative will be chosen over their objections and that the actions of the designated representative, over which they have no control, will result in noncompliance for which the minority owners will be liable.

Response: The Agency does not believe that it should require the designated representative to be certified by unanimous consent. Title IV does not explicitly authorize EPA to impose such a requirement. EPA does not believe that it should alter existing commercial arrangements absent express authorization from Congress to do so. (Some existing agreements among source owners, of course, may require unanimous consent). EPA's position is consistent with the approach taken in the Sanford amendment, which included what became sections 402(26) (designated representative definition) and 408(i) of the Act and which was aimed at "ensur[ing] that the existing relationship between the various parties with legal interests in an affected unit are [sic] preserved." (136 Cong. Rec. S3378, daily ed., March 28, 1990 (Senator Sanford)). In addition, requiring unanimous consent of all owners could give leverage to dissidents, allowing them to force majority owners into unreasonable concessions (which may or may not be related to the Acid Rain Program) simply to remove the objections.

(ii) Unanimous agreement on allowance decisions. Several of the commenters who supported unanimous consent in choosing the designated representative recommended that, at a minimum, EPA require that co-owners of a unit explicitly discuss and decide how to hold, use, and distribute allowances or apportion liabilities that might be incurred by the source. These commenters claimed that existing agreements, negotiated before allowances were created, do not confer adequate authority on the designated representative to handle allowances. These commenters assert that the Sanford amendment was designed to protect minority owners and that, under it, only a unanimous, new agreement, negotiated expressly to reallocate allowances, should be allowed to override the provision in section 408(i) that allowances otherwise be held and distributed in accordance with the ownership interests in the unit.

Response: The Agency agrees that section 408(i) was introduced to provide protection for minority owners without burdening EPA "with the responsibility of using scarce resources to rigorously examine the relationship between various parties whenever there are multiple holders in a unit." (136 Cong. Rec. S3379, daily ed., March 28, 1990 (Senator Sanford)). Since the section 408(i) protections are to be applied by the parties and, if necessary, the courts, the Agency has decided not to go beyond the specific requirements of section 408(i). Instead, the final rules incorporate the statutory language requiring allowances to be distributed in proportion to legal, equitable, leasehold, or contractual reservation or entitlement in the absence of a contract expressly providing for a different distribution. EPA will leave it to the parties involved to apply this provision and determine whether and under what circumstances a unanimous, new agreement is appropriate. The Agency believes that this approach gives minority owners the protection that they were granted in the Act, while preventing EPA from becoming embroiled in ownership disputes.

(iii) Limiting designated representative's discretion. Several commenters also suggested limiting the discretion of the designated representative in certain matters in order to protect minority owner interests. For example, commenters suggested that EPA: Require an agency relationship to be established between the designated representative and all co-owners; limit the ability of the designated representative to use allowances belonging to the joint owners or to sell allowances without express authorization from co-owners; require co-owners to enter into agreements concerning the holding and distribution of allowances; and take a more active role in oversight of the actions of the designated representative.

Response: The Agency has rejected these suggestions because they would require EPA to review and alter existing commercial arrangements, and oversee new arrangements, in the utility industry, a role for which EPA has neither the necessary expertise nor express statutory authority. The Agency's approach concerning section 408(i) of the Act preserves the minority owner protection granted under the Act.

(iv) Freezing allowance accounts. EPA asked for comment on whether it should freeze allowance accounts in the event of a dispute over the actions of the designated representative. Numerous commenters objected to EPA's proposal not to freeze allowances, claiming that a freeze would better protect against the trading of co-owner's allowances without their express authorization and would further ensure compliance. Other commenters supported EPA's proposed approach of not freezing allowances because it avoids having EPA become embroiled in private disputes among joint owners. These commenters believe that aggrieved multiple owners have

adequate protection through their commercial agreements and through the courts.

Response: The Agency has decided not to include in the final rule any provision requiring the freezing of allowance accounts in the event of an allowance dispute. The Agency believes that such a provision would undermine the functioning of the allowance market, which depends on the ability of third parties to rely on the full effectiveness of the recordation of an allowance transfer.

Freezing accounts automatically whenever any owner or operator claimed there was an allowance dispute would be extremely disruptive to the allowance market. Allowance trading could be disrupted frequently and at any time. Any majority or minority owner or operator could use such "claims" to force unable concessions. Providing for routine freezing of accounts where a claimed dispute seems meritorious would require EPA to evaluate the merits of disputes. Such routine evaluation of disputes is beyond the expertise of the Agency.

However, in § 72.4 of the final rule, the Agency reserves the right to take action (e.g., with regard to the Allowance Tracking System) in extraordinary circumstances that require action to ensure the orderly and competitive functioning of the allowance system. In addition, of course, parties may obtain injunctive relief, where appropriate, from the courts.

(v) Liability of owners and operators. Many commenters objected to provisions in the proposed rule that imposed liability on all owners and operators of a source or unit for violations of title IV of the Act and the regulations. The commenters pointed to language in the proposal concerning joint and several liability for owners and operators for violations of title IV requirements. They argued that the Act does not give the Agency authority to impose joint and several liability. In addition, commenters also objected to the preamble discussion of shared liability as an attempt to impose joint and several liability without authority.

In particular, the commenters argued that under title IV, liability for violations could only arise for persons who exercised operational control over the affected source or unit. Many utility units subject to Acid Rain Program requirements are owned by several entities, some of which possess minority ownership interests in the unit or source. They argue that existing contractual arrangements often cede responsibility for operational control, including compliance with environmental laws, to the majority owners. Due to these pre-existing contractual arrangements, commenters contend they lack any operational control sufficient to exert any influence on compliance with title IV requirements. In addition, commenters claimed the Agency unlawfully relied on section 408(i) of the Act to impose responsibility for compliance with title IV requirements on minority owners. These commenters suggested that EPA should amend the proposal to exempt minority owners from liability.

Response: The Agency does not agree that the final rule should exempt minority owners from liability but does agree that all provisions in the proposal that expressly establish joint and several liability on the owners and operators of an affected source or affected unit should be removed. The question of the liability of a specific owner and operator is best left to case-by-case determination in the context of enforcement against specific violations, rather than being resolved in the abstract in a rulemaking.

On one hand, various sections of title IV impose obligations on owners and operators without distinguishing between majority and minority owners or owners that are not operators. (See sections 408(h), 409(f), 411, and 412(e) of the Act). Moreover, by virtue of an ownership interest in a business or property, an owner may exercise influence over operation of a facility and help foster compliance with environmental laws. This may be true even if the owner cannot exercise unilateral authority or significant control over operations. It is important to encourage oversight of activities at one's business or property and discourage tacit approval or willful ignorance of illegal activities that threaten the environment.

On the other hand, the Agency does not blindly enforce against all parties regardless of their level of awareness, control, and responsibility for violations of the Act. EPA focuses enforcement efforts on those parties most truly culpable for violations. EPA and the courts look to the culpability of parties in determining liability and assessing civil penalties.

The Agency, therefore, has removed from the final rule language that expressly imposes joint and several liability on all owners and operators and is leaving the question of liability to case-by-case determination in proceedings before the Agency and, ultimately, the courts.

(vi) Liability of designated representative. Several commenters expressed concern that a designated representative would be liable, under the proposal, for violations by owners and operators.

Response: As a general matter, EPA expects that its civil and administrative enforcement actions under the Acid Rain Program usually will focus on the owners and operators of affected units that do not adhere to emission limitation requirements under the program (sections 404 and 405 of the Act). Designated representatives also have responsibilities under the Act and would be liable for violations of those responsibilities. The Act, at section 402(26), defines the designated representative as a responsible person authorized by the owner or operator to represent the owner or operator as to certain matters, including, for example, holding and transfer of allowances (section 403) and submission of and compliance with permits and compliance plans and related documents (sections 408(c)(1) and 408 (h)(1)).

It is EPA's statutory interpretation that a designated representative is not liable for acts or omissions that are not within the scope of his responsibility as designated representative. Under the Act, owners and operators shall be fully liable for the emission limitations (sections 404(a) and 405(a)) and monitoring requirements (section 412) for an affected unit and are responsible for operating the unit in compliance with those requirements. A designated representative would not be subject to liability for a unit's noncompliance with those requirements, except to the extent that the designated representative is an owner, an operator, or has control over the operation of the affected unit, or has been authorized by the owner or operator to ensure compliance with those provisions. Accordingly, where a particular violation resulted from acts or omissions that are within the scope of the designated representative's responsibilities, he will be subject to liability for that violation.

(4) Phase I Substitution Plans (Subpart D)

Section 72.41 of this regulation implements section 404 (b) and (c) of the Act, which give the designated representative the option of submitting a substitution plan. Under a substitution plan, the designated representative of a Phase I unit identifies affected units (i.e., Phase II units) that would not otherwise be subject to Phase I requirements and requests that they become Phase I units subject to these requirements. Since the substitution units will then receive allowances in Phase I, this approach may enable the

designated representative to achieve compliance with the sulfur dioxide emissions limitations required during Phase I in a more cost-effective manner.

(a) Common owner or operator. Section 404(b) of the Act allows the owner or operator of a Phase I unit to designate, as a substitution unit, a unit "under the control of such owner or operator." In interpreting this statutory language, the proposed rule stated that a designated representative is an operator and that a common designated representative for all units in a substitution plan would, therefore, fulfill the statutory requirement that the original Phase I unit and the substitution unit be under the control of the same owner or operator. The proposed rule also required that the units have the same designated representative regardless of any other common control.

Many commenters supported the proposed interpretation of the substitution provision and commended the Agency for providing flexibility. Some of these commenters also asked for clarification that a common designated representative would not be required if the units in a substitution plan had another owner or operator in common.

A few commenters disagreed with the Agency's interpretation. They felt that substitution plans should be limited to one operating company. They argued that Congress intended Phase I reductions to be achieved in the geographical areas of the country where the environmental effects of acid rain are most extreme (i.e., the eastern U.S. where most Phase I units are located).

Response: The Agency has upheld the proposed interpretation of the statute on legal and policy grounds. In general, a designated representative is not considered to be an operator. However, in some cases, his or her duties and level of responsibility can be equivalent to that of an operator. For example, in cases where the designated representative represents multiple sources without a common owner or operator that are participating in a Phase I substitution plan, the designated representative is responsible for coordination among the sources for purposes of submitting permit applications and compliance plans. In that case, the designated representative's responsibilities would be broad enough to bring him or her within the definition of operator because he or she would be responsible not only for determining that the compliance plans for the multiple units accurately reflect the provisions in the substitution plan, but also that the units comply with the substitution plan. See section 404(b) of the Act. The regulations provide (§ 72.41(b)(1)(i)) that the owners and operators of the units must act through a common owner, operator or designated representative. These types of important coordination activities and responsibilities make it appropriate to deem the designated representatives who perform them the equivalent of an "operator," and assure that the statutory concern regarding accountability will be met. See 56 FR 63015 (December 15, 1991). Accordingly, the statutory requirement in section 404(b) that a substitution plan involve a common owner or operator is satisfied.

Moreover, this approach offers utilities, particularly small utilities, flexibility to pursue least cost compliance. Small utilities would effectively be denied the flexibility available to larger utilities under the substitution provisions if participation were limited to a single operating company. A small operating company is less likely to have its own Phase II unit to designate as a substitution unit.

Although most Phase I units are located in the eastern U.S., Congress did not explicitly target a geographical area in identifying Phase I units, but instead used size and emissions rate as the criteria for identifying Phase I units. The Acid Rain Program clearly calls for nationwide reductions of sulfur dioxide without explicit requirements that the reductions be restricted to a specific geographical area. See 136 Cong. Record S17244, daily ed., October 26, 1990 and S16979, daily ed., October 27, 1990.

This rule also clarifies that units with different designated representatives will be acceptable in a single substitution plan, provided that they have another owner or operator in common. This approach is consistent with the Act, which does not require more than a common owner or operator. The rule clarifies that if an owner, operator, or designated representative is changed after a substitution plan is approved, the requirement to have a common owner or operator must continue to be met. If it is not, the substitution plan must be terminated beginning January 1 of the calendar year during which the change was made.

(b) "Unnecessary" substitutions. The proposed rule required calculations in a proposed substitution plan showing that the SO_2 emissions reductions obtained by all units in the plan would be greater than or equal to the SO_2 emissions reductions that would have been obtained by all such units without the plan. On its face, the proposed rule allowed calculations showing, under the plan, the substitution unit using all its allocated allowances and making no reductions and the original unit making 100% of expected reductions. The rule did not explicitly state whether such a situation, where no real substitution of emissions reductions was proposed, would be acceptable. Several commenters recommended that the Agency clarify that it will accept a substitution plan under which no transfer of reductions is proposed.

Response: The Agency has clarified in § 72.41(c) (3) and (4) of this rule to require that the total number of allowances allocated under a substitution plan not exceed the maximum amount allowed to be allocated to the substitution units under the rule; the allowances do not have to be allocated to or used at the original Phase I unit. This means that a substitution plan can be used solely for the purpose of making a Phase II unit subject to Phase I requirements. The Agency has taken this position because the alternative, i.e., allowing only those substitution plans that project a transfer of reduction obligations to the substitution unit, could be circumvented by the submission of plans projecting that one ton of SO_2 reductions be transferred. Since there is no obligation under the Act to actually carry out the projected transfer of emissions reduction obligations once the allowances are allocated under the plan and since the same total number of allowances will be allocated under a plan whether the transfer was to be one ton, 5000 tons, or zero tons, the Agency sees no reason to implement the substitution provisions in a manner that would require artificial projections and would lead to more burdensome paperwork requirements.

(c) Substitution plan allowance calculation. The proposal calculated the allowances allocated under each substitution plan based on the substitution unit's baseline multiplied by the lesser of the unit's 1985 actual SO_2 emissions rate, its 1985 allowable SO_2 emissions rate, or its most stringent federally enforceable allowable emissions rate at the time of application. Commenters presented opposing views on this requirement. Several commenters suggested that the Agency has no authority to limit substitution allowances to current federally enforceable emissions rates and that Congress was concerned about reducing emissions from 1980 or 1985 levels and not from current levels. Other commenters suggested that the Agency use current utilization at substitution units rather than their historical baseline in the calculation of

allowances. They argued that using this methodology would provide substitution units with allowances to account for growth at those units since 1985 and that credit for growth is justified.

Other commenters argued the opposite extreme, saying that any reduction required by law, State or Federal, should be considered a reduction that would have occurred in the absence of a substitution plan.

Response: The manner in which allowances for a substitution plan are calculated has been revised. Consideration of the most stringent federally enforceable emissions rate at the time of application has been eliminated in today's rulemaking. Only 1985 emissions rates will be included in the calculation.

The Agency's position on this issue hinges on interpretation of the requirement in section 404(b)(5) of the Act that emissions reductions under the plan be no less than without the plan. Section 404(b)(3) requires a proposed substitution plan to include the 1985 actual or allowable SO_2 emissions rate and makes no mention of the current allowable rate or current utilization. The Agency believes that this language in section 404(b)(3) strongly implies that the allowances allocated under a substitution plan are to be based upon the substitution unit's baseline multiplied by the lesser of its 1985 actual or allowable SO_2 emissions rate. This interpretation assumes that the reductions contemplated under the substitution plan are to be measured from 1985 levels and is generally consistent with the approach in sections 404 and 405 of achieving emissions reductions, by allocating allowances, from 1985–1987 levels. Any reductions in emissions rate made at a substitution unit since 1985 will not have resulted from title IV and will, thus, not be counted as reductions that would have occurred without the plan. The elimmation of current allowable rates from the calculation of substitution allowances is also responsive to the many commenters who were strongly opposed to EPA's proposal to annualize current allowable emissions rates using the procedures by which 1985 allowable rates were annualized for NADB.

Moreover, consistent with this interpretation, the 1985, not the current, utilization level of a substitution unit will be used in the calculation of allowances. Applying the concept of a 1985 starting point for both factors (emissions rate and utilization level) used to calculate reductions is internally consistent and follows the language of section 404(b)(3) of the Act. The Agency finds that the use of current data for utilization would not provide the overall reductions contemplated by the Act because it would provide allowances for growth at Phase II units. Finally, the use of well-established 1985–87 data not only provides more certainty that reductions will actually be achieved, but also facilitates implementation of the provision.

(d) Demonstration requirements. The proposal specifies procedures for demonstrating that a substitution plan meets the requirement of section 404(b)(5) of the Act that the plan "achieve the same or greater emissions reductions than would have been achieved by the original affected unit and the substitute unit or units without such substitution." The proposed procedures required the calculation of projected annual emissions reductions from each unit in the plan and the comparison of these reductions to those that would be achieved without the plan. Some commenters pointed out that the total number of allowances allocated under a substitution plan determines whether the total emissions reductions achieved under the plan will be adequate and that the distribution of the requested allowances among the original and substitution units is, thus, incidental.

The commenters suggested that the Agency should simply require calculation of the total allowances available under the plan and eliminate the requirement to calculate reductions to be obtained by each unit.

Response: The Agency agrees that calculation of the unit-by-unit reductions is unnecessary and has streamlined the procedures for demonstrating the section 404(b)(5) requirement accordingly. The rule limits the total number of substitution allowances allocated under the plan to the maximum number calculated to be available under the plan, i.e., an amount equal to the total tonnage the substitution units could have emitted if they were not under the plan and so did not have to make any emission reductions. This requirement fulfills the demonstration requirement because total reductions for the original and substitution units will equal what total reductions would be without the plan: 100% of expected reductions by the original unit and no reductions by the substitution unit under title IV. The rule then provides the designated representative the option to choose to have some or all of these allowances redistributed from the substitution units to the original Phase I units in the plan. If no redistribution is chosen, the designated representatives must simply indicate this in the application. The streamlined approach to this demonstration greatly reduces the burden of preparing a substitution plan. Allowances, of course, may always be transferred after they are allocated under the plan.

To further simplify the substitution plan, the Agency does not require that the original Phase I unit report its baseline, its 1985 actual and allowable SO_2 emissions rates, and its allowance allocation. This information has already been collected and appears in NADB and Table 1 of § 73.10(a). The Agency, therefore, has no need to require the source to report it. Further, although required to be reported under section 404(b)(4) of the Act, the substitution unit's proposed emissions rate under the plan is not required in the rule. Similarly, the substitution unit's projected emissions without the plan—a figure that is not mentioned in section 404(b)(3)—is no longer required. Because allocation of allowances under the plan is based on historical data, proposed or projected rates are not needed.

(e) NO_x applicability. The proposed rule stated that each substitution unit is affected for NO_x on the date that it becomes affected for SO_2. The final rule states only that each substitution unit will be affected for NO_x and defers specification of the deadlines and conditions to the future rulemaking on NO_x regulations to implement section 407 of the Act. Because substitution plans provide a lot of flexibility for sources to bring Phase II units into the program during Phase I, the implications for NO_x emissions could be significant. For this reason and because many related issues concerning NO_x requirements have not been finalized, the details of NO_x applicability for substitution units have been deferred.

(f) Termination of plans. Under the proposal, substitution plans may be terminated through an administrative permit amendment, provided that the designated representative surrenders the allowances allocated under the substitution plan for the years of the termination. The final rule clarifies this provision to specify that notification to terminate a substitution plan must be submitted to the Administrator by at least 60 days before the allowance transfer deadline applicable to the first year for which the termination is to be in effect. This should allow the revision of the permit and the deduction of allowances to take place by the allowance transfer deadline. The Agency believes that retroactive terminations limited in this way should

be allowed in order to maximize flexibility in compliance.

(5) Phase I extension plans (subpart D). Section 72.42 of this regulation implements section 404(d) of the Act. A Phase I extension plan allows the designated representatives of units that commit to install technologies achieving 90% reduction of sulfur dioxide to obtain a two-year extension of the deadline for meeting Phase I emissions reduction requirements by applying for additional allowances from a special allowance reserve. The designated representatives of units that will transfer their emissions reduction obligations to the units installing control technologies may also request reserve allowances.

(a) Early ranking procedure. Prior to the proposal, the Agency determined, in consultation with the regulated community, that the 3.5 million allowance reserve for Phase I extensions was likely to be oversubscribed. Because the Act specifies that the Administrator must act on each application in the "order of receipt," some applicants would, therefore, not receive reserve allowances. The appropriate method for distribution of Phase I extension reserve allowances thus became one of the most controversial issues encountered in this rulemaking. Faced with the prospect of a drawn out debate, the regulated community advised EPA that certainty regarding the chances of receiving Phase I extension reserve allowances at the earliest possible date was important. For this reason, the Agency proposed an early ranking procedure to determine the order of receipt of Phase I extension applications prior to submission of a Phase I permit application. A telephone queuing procedure was proposed as the method for ranking these applications.

The Agency received extensive comment on this issue from the regulated community, high sulfur coal interests, low sulfur coal interests, equipment vendors, Congressmen and Senators, and a few environmental groups. Almost all commenters urged the Agency to abandon telephone queuing. Even those commenters who disagreed on what the alternative should be agreed on this point. The most frequently cited reasons for eliminating telephone queuing were cost to industry and the Agency and concerns about the security of the queuing system.

On one hand, commenters who favored a pro rata distribution of Phase I extension reserve allowances to all qualified applicants, argued that telephone queuing or any other first-come, first-served procedure fails to implement the intent of the Phase I extension provision. They argued that the provision was meant to buffer the economic impact of title IV on those utilities and States that are most dependent on high sulfur coal. The intent, they claimed, was to encourage the installation of control technology. A pro rata approach would ensure that all qualified utilities would receive at least some share of the reserve allowances and would, thus, allow more of them to proceed with the installation of controls.

On the other hand, low sulfur coal interests argued that the language of section 404(d) of the Act does not allow for pro rata distribution and supported the Agency's proposal to act on applications one at a time on a first-come, first-served basis until the allowances run out. These commenters did not argue, however, that the proposed telephone queuing procedure was the best way to implement their recommended approach. Some of the first-come, first-served supporters suggested a lottery drawing instead, pointing out that the effect would be the same as that of a telephone queue, at much less cost to sources and the Agency and with fewer security concerns. Some commenters who supported a pro rata approach also indicated that a lottery drawing would be satisfactory if the Agency decided against pro rata.

Response: The Agency has considered all of these comments carefully and has determined that a lottery drawing is consistent with the statutory language and will be the least burdensome and most expeditious method to provide an early ranking of Phase I extension applications. A lottery is also the only approach that commenters from both points of view seemed willing to accept. This was an important factor in the Agency's decision since litigation on this provision would only delay the certainty that is so important to the regulated community.

The rule specifies that the Administrator will begin receiving early ranking applications on the 40th day after promulgation of this rule. Forty days have been provided so that sources will have adequate time to obtain and read the rule and to appoint a designated representative. All early ranking applications received on the same day will be deemed to be received simultaneously. If the applications received on any one day result in the reserve to be oversubscribed, a public lottery drawing will be held to determine the order in which to act on each application received on each such day. About two weeks will elapse between the time that the source is notified of the lottery and the day on which the lottery is to be held so that applicants will have the opportunity to negotiate among themselves or to drop their applications if desired.

The conditions on the rank order, once it is determined, remain the same as those proposed. Several commenters did, however, ask for clarification that an application would not lose its place in the rank order if the information originally submitted requires adjustments. Only complete early ranking applications will be given a rank order. An application that contains all of the requested information is considered complete and is not rendered incomplete by the need to correct later any of the information. Once a complete application is given a rank order, adjustments can be made without changing the rank order of the application. The addition of new control units will not, however, be considered an adjustment. Similarly, the inclusion or exclusion of transfer units will be allowed as an adjustment but the total number of Phase I extension allowances requested will not be increased. The addition of new control units or additional requested allowances to an existing application would have the same effect as permitting submission of a new application ahead of other existing applications. Allowing such changes to existing applications would therefore contradict the requirement that applications be considered in order of receipt.

Allowances will be awarded to each unit based on the information in the early ranking application. The allowances will not actually be allocated (i.e., they will not appear in each unit's subaccount) until a full permit application containing a Phase I extension plan has been acted upon by the Administrator and each unit's permit has been issued.

It must be noted that one utility has filed suit against the Agency seeking court intervention requiring EPA to rank its request for allowances based on the March 1991 submission date of the request. *Monongahela Power Co., et al.* v. *Reilly,* Civ. No. 91–137–C (N.D. W.Va). While the case remains unresolved, the possibility exists that EPA may, at some later date, be required to revise the ranking procedures.

(b) Qualifying Phase I technology contract. The proposal required a fully executed contract for construction of qualifying Phase I technology contingent only on the receipt of Phase I extension reserve allowances.

Several commenters found the proposed rule language specifying requirements for the qualifying Phase I technology contract to be unduly

restrictive. Commenters pointed out that section 404(d)(2)(B) of the Act states that the contract "may be contingent upon the Administrator approving the proposal" and does not restrict the contract to a single contingency. Many commenters also suggested that the proposed requirement for a single contract for qualifying Phase I technology does not reflect the complexities of such agreements.

Response: The rule language has been modified to reflect more closely the statutory language. Other contingencies are, thus, permissible. However, the contract must be a binding agreement between the parties for installation of equipment capable of at least 90% reduction of SO_2.

The rule language has also been modified to, consistent with the language in section 404(d)(2)(B), allow for multiple contracts. The rule still requires contracts covering activities up to and including construction of the main scrubber module or, in the case of precombustion or combustion technologies, construction of the primary components of the removal system.

In addition, the rule specifies that submission of full contracts for qualifying Phase I technology with the early ranking application and with the Phase I extension plan will not be required. Instead, a source may submit, for each contract, a letter agreement that includes: (1) Identification of the qualifying Phase I technology to which the contract applies, (2) the parties to the contract, (3) the date each party executed the contract, (4) identification of the units to which the contract applies, (5) a list identifying each provision of the contract, (6) any dates to which the parties agreed, (7) the total dollar amount of the contract, and (8) the signature of each party and the date that each party signed. The listed information is needed to review the Phase I extension and early ranking applications. Condensing this information into a brief, but binding summary will streamline EPA's review and will reduce significantly the volume of documentation required to be submitted by each applicant.

The rule also specifies that a copy of the actual contract must be kept on file, and must be sent to the Administrator upon request. This requirement is necessary because section 404(d)(2)(B) of the Act requires that each extension proposal provide a copy of an executed contract for the design engineering, and construction of the qualifying Phase I technology. Since all permit applications are placed in a public docket, the statutory provision has the effect of requiring the contract to be available to the public. The opportunity for public examination of the contract must, therefore, be preserved. Elimination of the requirement to submit the entire contract reduces the paperwork burden on the source and on EPA while maintaining the opportunity for public review.

(c) *Calculation of reserve allowances.* *(i) General concept.* The proposal asked for comment on the Agency's interpretation of the procedures for allowance awards to each unit under a Phase I extension plan. The proposal provides that each control unit may receive reserve allowances based on the lesser of the unit's average annual emissions for 1988 and 1989 or the unit's projected uncontrolled emissions for 1995 and 1996 regardless of when during the extension period the control technology is actually installed. The Agency asked for comment on an alternative interpretation whereby the control unit would receive allowances based on uncontrolled emissions only if the control technology was not yet installed. Under this scenario, the control unit would still get reserve allowances, but the number would be based on the difference between their basic allowances and the number of tons they would emit with the controls installed.

Most commenters supported the proposed interpretation, although some commenters preferred the alternative interpretation because it ties reserve allowances more closely to the actual operations at a unit. Many commenters also requested that the final rule clarify that reserve allowances for transfer units are to be calculated using the same principles as applied to control units.

Response: The rule maintains the interpretation for calculating reserve allowances that was proposed. The Agency believes that the intent of the Phase I extension provision was to allow qualifying utilities to operate, during the extension period, as they would have been able to operate without title IV and to bank that amount of allowances if they installed control technology prior to January 1, 1997. See 136 Cong. Record, S2532, daily ed., (March 9, 1990) (Senator Bond). Under this interpretation, all units receiving the extension are treated in the same manner throughout the extension period, regardless of whether they install controls earlier than required by the Act.

The rule also clarifies that reserve allowances for transfer units are calculated using the same principles as applied to control units. This means that transfer units also receive reserve allowances based on the lesser of their average annual emissions for 1988 and 1989 or their projected uncontrolled emissions, i.e., what emissions would have resulted from operation of the unit in the absence of title IV.

(ii) 1988 and 1989 average annual emissions. The proposal specified the 1988 and 1989 emissions to be used for each unit in the calculation of Phase I extension allowances in proposed Appendices A and B. These figures were based on data reported on EIA Form 767 filed in those years. The EIA data was analyzed by EPA using the methodology in the NADB Version 2.1 Technical Support Document, Appendix D at 2.

Some commenters disagreed with the figures published in the proposal.

Response: The Agency has removed proposed Appendices A and B, with the 1988 and 1989 sulfur dioxide emissions data, from the rule. Individual figures therefore can be revised without revising the rule. EPA, in reviewing Phase I extension applications, will generally rely on the designated representative's certification that the data is correct. If a dispute over the data arises during the permit issuance process, EPA will rely on whatever data EIA reports to EPA for the unit in question and will convert this data to an annual tonnage figure using the methodology in the document cited above, which methodology is now contained in the final Appendix C of this part.

The proposal also stated that allowances for control and transfer units would be limited not only to the average annual emissions for 1988 and 1989, but also to the most stringent federally enforceable allowable emissions limitation for those years. Thus, if a unit had been out of compliance in those years, it would not receive reserve allowances for the emissions above the compliance level. Commenters on this issue questioned both the Agency's authority to impose this restriction and the procedures that were proposed for the annualization of allowable emissions rates. Commenters from the regulated community argue that the Agency has no authority to consider allowable emissions in this context since section 404(d)(4) specifically provides for consideration of average annual emissions and makes no mention of allowable emissions. This contrasts with other sections of the Act (e.g., section 409(c)) that expressly refer to allowable emissions. Commenters also claim that the Agency lacks authority to use the annualization procedures specified in the Act for allowable 1985 emissions rates for the annualization of other emissions rates.

Response: Because section 404(d)(4) expressly limits reserve allowances by only the average annual emissions for 1988 and 1989, the requirement to limit reserve allowances to 1988 and 1989 allowable rates has been eliminated altogether.

(iii) Projected emissions for 1995 through 1999. The proposed rule specified that projected emissions for 1995 through 1999 at control and transfer units be based on projected annual utilization as reported on EIA Form 767 and projected emissions rate for each year. This emission rate could not exceed the most stringent federally enforceable allowable emissions rate in lbs/mmBtu.

Commenters objected to the use of the EIA form as a source of projected utilization data, both because it does not provide annual projections for the appropriate years and because using previously reported projections does not provide sources enough flexibility. Commenters suggested that EPA simply require "good faith" utilization projections and asked EPA to clarify that because these projections are used to calculate Phase I extension reserve allowances, they would not need to be revised once the Phase I extension plan had been approved and the allowances allocated.

Some commenters objected to restricting projected rates to the most stringent federally enforceable allowable emissions rate. In addition, although neither the proposed rule nor the proposed preamble explicitly stated that the most stringent federally enforceable rate used for comparison to the projected rate would be annualized, some commenters felt that annualization was implied. They disagreed with the requirement to express an allowable rate in annualized form rather than in the format in which it is enforced.

Response: The Agency agrees with the majority of commenters that the use of EIA Form 767 as a source for projected utilization figures is not workable. The final rule simply requires projected annual utilization for 1995 through 1999. EPA intends that these projections be good faith projections. In addition, as commenters suggested, these projections need not be revised once the Phase I extension plan is approved.

The final rule similarly requires projected uncontrolled or controlled emission rates for 1995 through 1999 (as applicable), and EPA intends that they be good faith projections. EPA maintains that any projected emissions rate that exceeds the unit's most stringent federally enforceable emissions rate promulgated as of the filing of the Phase I extension plan will, on its face, not be good faith. As with the 1988 and 1989 actual emissions, EPA will generally rely on the certification of the designated representative. Should a dispute arise during the permit issuance process, EPA will convert the unit's most stringent federally enforceable emissions rate at the time of application to lbs/mmBtu using the conversion methodology in the NADB Version 2.1, Technical Support Document, Appendix D at 2. This methodology is now set forth in the Appendix B of the final rule. If there are two or more applicable federally enforceable rates, the rates will be converted to lbs/mmBtu, but not annualized, and the lowest rate will be compared with the projected emission rate.

(d) NO_x applicability. The proposal stated that control units must comply with nitrogen oxides reduction requirements on the date that the unit shuts down to install the control equipment and that transfer units are subject to nitrogen oxides reduction requirements on January 1, 1995.

Many commenters pointed out that the proposal seems inconsistent with section 407(a) of the Act, providing that a Phase I extension unit is subject to NO_x requirements when it must meet SO_2 reduction requirements, and section 404(d)(1), postponing SO_2 reduction requirements for such units for two years.

Response: The Agency agrees. The rule states that both control and transfer units are subject to nitrogen oxides requirements on January 1, 1997 in accordance with section 407 of the Act and regulations implementing section 407.

The only caveat to this provision is that transfer units not transferring the total number of emissions possible (i.e., the lesser of average annual emissions for 1988–1989 or projected uncontrolled emissions during the extension) to a control unit will not be exempt from nitrogen oxides requirements during those years that the transfer is partial, unless the transfer unit is the last unit allocated allowances under the Phase I extension plan. If the designated representative is not requesting the full amount of reserve allowances for which a transfer unit might be eligible, then the unit is subject at least in part to the SO_2 reduction requirements under title IV (section 407(a)) and so is subject to applicable nitrogen oxides emissions limitations on January 1, 1995. This interpretation was necessary to prevent gaming whereby numerous transfer units would be attached to each control unit, only requesting a few reserve allowances for each and thereby making them all exempt from nitrogen oxides requirements. The Agency does not believe such widespread exemption from nitrogen oxides reductions was contemplated under this provision and has, therefore, explicitly prevented it. However, if a transfer unit is the last unit allocated allowances under a Phase I extension plan and cannot receive all of the allowances for which it is eligible, e.g., because the Phase I extension reserve is depleted, the unit will be exempt from nitrogen oxides requirements until 1997. In the latter case, the partial transfer is unavoidable and so should not disadvantage the transfer unit.

(e) Demonstration of 90% removal efficiency. The proposal required control units to demonstrate 90% removal efficiency for qualifying Phase I Technology on an average annual basis beginning upon commencement of operation of the technology. A requirement to perform a 30-day start-up test was also proposed.

The Agency received many comments on this provision. Many commenters claimed that the average annual demonstration was unnecessary since under section 404(d)(7) of the Act, control units must not exceed the projected tonnage emissions of sulfur dioxide in their permit application. Many commenters also suggested that the demonstration not be required beginning upon commencement of operation of the qualifying Phase I technology. They suggest that since, with the 2-year extension, the deadline for operation of the technology is January 1, 1997, the requirement to demonstrate 90% removal should not begin until that date. In addition, commenters argued that if 90% removal is to be determined on an annual average basis, as proposed, a start-up test that can be repeated until the end of the calendar year is meaningless and redundant.

Response: Section 404(d)(2)(E) states that the control unit must project the number of allowances expected to be necessary for annual operation after the qualifying Phase I technology has been installed. However, the requirement not to exceed projected tonnage emissions does not ensure that 90% control will be achieved since the limitation could be met by reducing load or by using a lower sulfur fuel. Because the statutory definition of qualifying phase I technology requires that the technology achieves 90 percent reduction and because this requirement is a condition for awarding reserve allowances that provide a substantial economic benefit at the expense of other units, the

Agency does not agree with the commenters who suggested that the provisions based on section 404(d)(7) of the Act provide adequate demonstration and that the proposed additional demonstration be removed. The Agency does agree that the requirement to demonstrate 90% removal should not begin until January 1, 1997 and has revised the rule accordingly.

The proposed demonstration has also been revised to eliminate the requirement to perform a 30-day start-up test. The Agency agrees with commenters that both tests are not necessary. The rule does, however, require the designated representative to submit, for informational purposes, a copy of the start-up test results upon which the vendor is released from liability for providing a technology through which 90% sulfur dioxide reduction is achievable.

(f) Failure to meet 90% removal efficiency. The proposal specified that Phase I extension reserve allowances would be allocated conditionally until 90% removal was demonstrated. Following the demonstration each year, that year's reserve allowances would be allocated. Failure to achieve 90% removal efficiency would result in the allocation of fewer reserve allowances than had been set aside for that unit. This failure to receive reserve allowances would be in addition to any allowances that the Agency would deduct, under section 404(d)(7) of the Act, for failure to meet the projected tonnage limit specified in the permit.

Several commenters argued that the Administrator does not have the authority to withhold reserve allowances in this manner and that if the Agency chooses to keep the 90% removal demonstration, reserve allowances should not be affected by failure to meet the requirement. In addition, several commenters have argued that the "conditional" allocation and subsequent removal of some reserve allowances for failure to meet the demonstration requirements would unreasonably limit the utility's ability to realize the economic incentives that reserve allowances were meant to provide.

Response: Section 404(d)(6) of the Act authorizes the Administrator to allocate reserve allowances to each control unit with qualifying Phase I technology (i.e., technology that achieves 90% reduction) for the years in which the technology is required. The Act does not specify the timing of this allocation. The Agency, therefore, has the discretion to withhold allocation until all requirements are met, e.g., until the technology achieves 90% reduction. However, the Agency has revised the proposal so that reserve allowances will be allocated when the Phase I extension plan is approved, but the failure to demonstrate 90% removal efficiency in a particular year will result in an appropriate deduction of allowances after the end of the year. The Agency has made this revision to provide those utilities granted a Phase I extension with more flexibility. However, if the Agency could not require such a deduction after the end of each year, the Agency believes that the statute would require the alternative approach of delaying allocation of reserve allowances each year until the annual 90% removal requirement had been demonstrated.

(g) Reallocation of returned allowances. The proposal did not explicitly address the issue of reserve allowances that might be returned to the Administrator. Several commenters asked the Agency for clarification on how these allowances would be used.

Response: The final rule specifies that any reserve allowances made available at any time will be allocated in rank order to the next application that still meets the requirements for a Phase I extension.

(6) Phase I Reduced Utilization Plans and Underutilization Requirements

The reduced utilization provisions arise from a statutory requirement in section 408(c)(1)(B) of the Act. This paragraph prevents a Phase I unit from circumventing its emissions reduction requirements by shifting load to units that are not subject Phase I requirements. The statute requires an up-front plan when a unit is planning to shift its load in order to reduce its emissions.

Section 72.43 of the final rule outlines the requirements of a reduced utilization plan and describes the circumstances that dictate its submittal. Subpart I delineates the procedures that are required by all Phase I units at the end of each year in Phase I. Specifically, § 72.91 contains formulas that each Phase I unit must use to (i) calculate its "adjusted utilization" to determine whether it was underutilized and (ii) calculate the extent to which it accounted for underutilization through a reduced utilization plan. A unit is underutilized if its "adjusted utilization" is greater than zero. Section 72.92 contains a sequence of accounting steps that are mandatory for any unit that cannot fully account for underutilization through a plan. These steps involve a series of formulas used to determine the number of allowances, if any, that must be surrendered as a result of a shift in load that resulted in increased emissions at a unit not subject to an emissions limitation in Phase I.

As a result of public comment, changes were made to the proposed regulations. While the intent of this section remains basically the same, the Agency believes that the changes more effectively carry out this intent.

(a) Reduced utilization planning requirement. The Agency does not believe that section 408(i) of the Act requires a unit to file a reduced utilization plan in all circumstances involving underutilization and load shifting. As discussed in the preamble of the proposal, this interpretation of section 408(c)(1)(B) is contingent on the Agency's ability to require a unit to surrender allowances under section 403(d) to account for the emissions resulting from certain load shifting. In the absence of the ability to require such surrender, the Agency believes that the statute would require application of section 408(c)(1)(B) to virtually all cases of underutilization in order to ensure that the emissions reductions mandated by the statute are achieved. See Senate Rep. No. 101–228 at 334 (1989). The Agency continues to reject this latter interpretation of section 408(c)(1)(B) of the Act.

Commenters presented different scenarios in which they argued that it was unclear whether the planning requirement applied. The majority of them involved utilities that were planning to comply by a means other than reducing utilization. As a result of this alternative method, the utilities' Phase I units would be underutilized.

Response: Section 408(c)(1)(B) requires an up-front plan where the owner or operator proposes to meet the requirements of that section by reducing utilization of the unit as compared with its baseline or by shutting down the unit. In applying this section, the Agency is distinguishing between knowing that incidental underutilization may happen and making it happen for the purpose of compliance. Under the Agency's interpretation, it is only those utilities that underutilize for the purpose of compliance that are obligated to file a reduced utilization plan, provided that all other underutilization is subject to the allowance surrender requirement.

(b) Economic dispatching. Of particular concern to the commenters was the uncertainty as to whether underutilization caused by economic dispatching will require a reduced utilization plan. Under the proposal, if a utility did not fall under one of the listed safe harbors (which could cover a utility that carried out economic

dispatching) and had factored in the value of allowances avoided, saved, or banked into its economic dispatching, EPA could deem the utility to be in violation of the planning requirement. The use of a dispatch order based only on operating costs, and not the cost of emitting SO_2, could exempt a unit from the section 408(c)(1)(B) planning requirement. However, this approach would defeat the purpose of title IV, which is to create an allowance market that assigns SO_2 emissions a value and thereby enables utilities to consider the value of allowances needed or saved, along with other operating costs, in making dispatching decisions.

Response: EPA has therefore modified its approach by explicitly including economic dispatching as a safe harbor from the planning requirement. This safe harbor applies whether the unit obtains compensating generation from within or outside the unit's dispatch system. It also applies where underutilization is caused by an order of a utility regulatory authority issued to achieve economic dispatching. In addition, the Agency has eliminated regulatory language suggesting that consideration of the value of allowances in dispatching indicates that there was an unlawful failure to plan. There will be no retrospective determination of violation of the planning requirement under § 72.43 if a unit is underutilized due to economic dispatch and surrenders allowances as prescribed in § 72.92.

(c) Indicators. The Agency received comments addressing the indicators that should be considered to determine on a case-by-case basis the applicability of the planning requirement in section 408(c)(1)(B).

Response: The Agency has clarified that these indicators will be used when a utility is not operating under a reduced utilization plan and cannot fully account for its underutilization under any of the safe harbors. In that situation, the Agency will consider the indicators and any relevant evidence and determine on a case-by-case basis whether there was a planning violation. In addition, as discussed, the indicators have been modified, consistent with the Agency's approach concerning economic dispatch.

(d) Nitrogen oxides requirements. Under the proposal, compensating units would not be subject to nitrogen oxide requirements of section 407 of the Act. EPA received comments both supporting an interpretation of section 408(c)(1)(B) that would result in only SO_2 requirements applying to compensating units, not NO_x requirements, and supporting an interpretation under which both SO_2 and NO_x requirements would apply. The comments reiterated the arguments set forth in the preamble on the proposal.

Response: Like the proposed rule, the final rule provides that designated compensating units that would not otherwise be subject to Phase I of the Acid Rain Program are not subject to the Phase I NO_x limitations. As the Agency stated in the preamble to the proposed rule, EPA considered two opposing views on this issue, and noted that textual arguments can be made from the statutory language to support either view. (For a discussion of these opposing views, see the preamble to the proposed rule at 56 FR 63022–63023 December 3, 1991). After considering the comments on this issue, EPA has determined to adopt in its final rule the interpretation that EPA proposed, because the Agency has concluded that this interpretation best implements Congressional intent. *See Chevron, U.S.A.* v. *Natural Resources Defense Council,* 467 U.S. 837, 843, 865 (1984).

EPA reached this conclusion based on its belief that, in enacting the reduced utilization provision of section 408(c)(1)(B), Congress was concerned with compliance with SO_2 emission tonnage limitations in Phase I. In enacting section 408(c)(1)(B), Congress was not addressing compliance with NO_x emission rate limitations. This is shown by the phrase in section 408(c)(1)(B) expressly providing that an otherwise unaffected compensating unit is to be deemed an affected unit under section 404, but omitting any mention of section 407.

Moreover, the legislative history is clear that Congress' concern in enacting section 408(c)(1)(B) was to prevent circumvention of SO_2 emission tonnage limitations. S. Rep. No. 228, 101st Cong., 1st Sess. 334 (1989). Section 408(c)(1)(B) does not refer to just any utilization reduction at a unit, which could also apply to the NO_x provisions of section 407, but only to a unit's utilization reduction *as* compared with its *baseline.* Reducing utilization below the baseline level is germane only to compliance with the SO_2 tonnage limitations and allowances. It is not a method of compliance with the NO_x limitations of section 407, which are emission rate limitations.

With regard to the SO_2 requirements, the baseline is the utilization level that the statute multiplies by 2.5 lbs/mmBtu to determine the SO_2 allowance allocations. Thus, a unit could seek to comply with Phase I SO_2 requirements by keeping its emission rate above 2.5 lbs/mmBtu and reducing its utilization *below its baseline.*

The baseline utilization level has no such significance for compliance with the NO_x rate limitations of section 407, since a unit's emission rate is independent of whether it operates at, above, or below its baseline utilization level. Furthermore, utilization reductions below baseline are not relevant with respect to compliance with the Btu-weighted average annual emission rate under a section 407(e) Phase I NO_x averaging plan. Nor are such reductions relevant with respect to the calculation of penalties under section 411 for the number of tons emitted in excess of a unit's NO_x emissions limitation requirement. Both of those provisions are concerned with the total amount of tons emitted during the past year, based on a unit's actual utilization during that year.

In summary, Congress' use of the baseline as the utilization reduction trigger for section 408(c)(1)(B) indicates that the provision is aimed only at utilization reductions for compliance with the SO_2 tonnage limitations, and consequently, that the NO_x requirements do not apply to compensating units.

(e) Sulfur-free generators. (i) Conversion of Kwh to mmBtus. In the proposal, EPA requested comment on how to convert kilowatt hours of sulfur-free generation into mmBtu. The conversion factor is used to calculate the amount of sulfur-free generation that accounts for underutilization (which is in mmBtus) at the Phase I unit. Several commenters suggested using 10,000 Btu/kwh as an average heat rate.

Response: Given the wide range of variation in heat rates among Phase I units, EPA rejects this approach as being unacceptably inaccurate. The more accurate method, which the Agency has adopted, is to use the heat rate of the unit reducing utilization. The same conversion method is used to convert Kwh savings from energy conservation to mmBtus and to determine how much load is shifted to a reducing unit by a compensating unit.

(ii) Benchmark year. Under the proposal, in order to receive credit for sulfur-free generation, the designated representative of the reducing unit had to demonstrate an increase in generation at that generator as compared to the previous year. The Agency received comments requesting a change in the benchmark year used to demonstrate that increase. All commenters objected to comparing the current year's generation with the previous year's generation. The commenters recommended using 1985–87 average

generation for comparison in a manner analogous to the use of baselines under title IV.

Response: The Agency agrees that the recommended approach is reasonable, considering that there is no intent under section 408(c)(1)(B) to penalize utilities that have shifted to sulfur-free generation since 1987. Therefore, under the final rule, a Phase I unit will not have to surrender allowances to the extent that it can demonstrate an increase in generation at a sulfur-free generator above the 1985–87 average generation and above any sales growth in the Phase I unit's dispatch system. Sales growth in the Phase I unit's dispatch system is used as a proxy for sales growth in the sulfur-free unit's system, which data may not be available.

(f) Energy Conservation. (i) Verification of energy conservation and improved unit efficiency measures. The proposal outlined a procedure under which a utility using energy conservation or improved unit efficiency measures would verify actual reductions for three quarters of a year. An estimate of fourth quarter savings would be added to the actual reductions to determine the amount to be claimed in the annual compliance certification report. Within 90 days of the end of the year, a verification of the fourth quarter savings was to be submitted. This approach required separate verification of the first three quarters and the last quarter. Moreover, commenters asserted that the proposed rule may not provide sufficient time for accurate verification. In addition, EPA received comment on the lack of rigor in, and consistency among, States' verification methods of verifying savings from energy conservation.

Response: In light of these comments and in order to be consistent with the 6-month verification period allowed in connection with applications for allowances in the Energy Conservation and Renewable Energy Reserve under part 73, the Agency has made some changes to the verification procedure. To promote accurate and economical verification, utilities using energy conservation and improved unit efficiency will make a good faith estimate of savings for the entire year in the annual compliance certification report. A confirmation report showing verified annual savings is not due to EPA until July 1 of the following year. Further, because of inconsistencies among States' verification methods, savings from energy conservation must be verified in accordance with requirements in the final part 73 (concerning verification for purposes of obtaining allowances from the Energy Conservation and Renewable Energy Reserve), which have been strengthened in light of this problem. See the portion of the preamble addressing part 73 for further discussion of this issue.

(ii) Return of allowances. The proposal required deduction of allowances where heat input savings resulting from the use of energy conservation or improved unit efficiency measures were overestimated for the fourth quarter. Commenters requested that EPA return allowances surrendered when the annual compliance certification report underestimated energy conservation savings under a reduced utilization plan. Commenters argued that deducting allowances for overestimates while not returning allowances for underestimates was unfair and would inevitably lead to consistent overestimation of conservation savings.

Response: The Agency has provided in the final rule for the return of allowances in the case of underestimated energy savings for the year as well as allowance deduction for overestimates. The final rule contains a procedure for determining whether differences between the estimated and verified savings result in the deduction or return of allowances and in a change in the compliance status of the unit (e.g., excess emissions) for the year for which savings were estimated.

(g) Definition of "dispatch system". Utility system is defined as a unit's utility operating company as listed in the NADB. In the proposed reduced utilization provisions, utility system was used as the universe of units for establishing parameters such as system-wide sales decline, the Phase I aggregate utilization test (i.e., the calculation of the net utilization of a group of Phase I units), and savings from energy conservation and improved unit efficiency measures. Commenters opposed the proposed definition of utility system, claiming that it does not consider the manner by which sources are centrally dispatched. Some comments suggested broadening the definition to include holding company, while others suggested a definition as broad as power pool.

Response: The Agency has adopted a new term, "dispatch system", and defined it in § 72.2 to include, at the discretion of the designated representative with certain conditions, an operating company, holding company, or power pool if they are centrally dispatched. Although the Agency is adopting this broad definition, this flexibility brings many complications. It must be understood that for verification purposes and to prevent double counting, all units within a given dispatch system must all apply the same definition of dispatch system and use consistent data for purposes of compliance with reduced utilization and allowance surrender requirements. If a group of units wants to adopt a definition of dispatch system that is broader than utility system, the designated representatives of those units that will be in the dispatch system must jointly submit an identification of that dispatch system, listing all units that agree to be treated as such a group. In addition, a dispatch system may be required at the end of the year to submit a report with certain dispatch system data. In order to ensure the use of consistent values, all the designated representatives of units in a dispatch system must certify together that the data is accurate and that their submissions for their respective units will be consistent with this data.

The Agency reserves the right to reject a unit's designation of a dispatch system broader than the utility system if the submissions of all units claimed to be in that dispatch system are not consistent. For example, if two designated representatives of units in the same dispatch system submit annual compliance certification reports with different values for dispatch system sales decline, all annual compliance certification reports received from any unit in that system will be rejected. At that time, each designated representative will be required to resubmit the annual compliance certification report with its dispatch system defined as the utility system. The Agency is adopting this approach because the most effective way of ensuring consistent submissions by all units in a dispatch system is to put the burden of ensuring consistency on those units.

Consistent with the approach of increasing flexibility by basing the reduced utilization provisions on the "dispatch system," the Agency has determined that a unit with multiple owners that is dispatched into more than one system should also have more flexibility. Each Unit has one utility system, i.e., the system of the utility that operates the unit, and without further flexibility, only that system (or a dispatch system of which the utility system is a part) could be considered for purposes of applying the reduced utilization provisions. Under the final rule, the designated representative of a multi-owned unit may petition the Administrator to apportion the unit so that an owner's portion of the unit is treated as part of the dispatch system

into which it is dispatched. An owner's portion of the unit is its percentage ownership interest in the capacity of the unit. The apportionment is only for purposes of calculating a unit's adjusted utilization and the number of allowances that must be surrendered. The designated representative of the unit remains responsible for surrendering allowances for the entire unit, and the deduction of allowances is still from the Allowance Tracking System account of the unit.

If the petition is approved, an owner's portion of the unit will be treated as a separate unit from the rest of the original unit solely for such calculations. Adjusted utilization will be calculated separately under § 72.91 for the owner's portion and for the remaining portion of the original unit. Most of the data used in the calculation will be apportioned based on ownership in the unit's capacity. Plan reductions will be treated in a manner determined by the Administrator on a case-by-case basis. This is because the specific facts of each case may affect how such plan reductions should be handled.

Similarly, where the petition is approved, the allowance surrender formula in § 72.92 will be applied treating the owner's portion of the unit as a separate unit from the rest of the original unit. The designated representatives of the unit and of all dispatch systems that include any portion of the unit must submit all reports required under §§ 72.91 and 72.92 and demonstrate that they are using properly apportioned data that does not result in any undercounting or double-counting. Where the designated representatives fail to meet their burden, the Administrator may require them to resubmit all reports and return to treating the entire unit as a single unit.

(h) Annual compliance certification report. (i) Basic approach of allowance surrender formulas. Under the proposal, generation compensating for underutilization of a Phase I unit was segregated according to whether the generation could be attributed to a known unit in order to determine how many allowances the Phase I unit should surrender. To the extent load was shifted to other Phase I units in the same utility system, no allowances would be surrendered for the unit's share of such a shift. If load were shifted to undesignated but known non-Phase I units, that utilization would be multiplied by the weighted emission rates of those known units. The product would be used to determine the number of allowances to be surrendered for those shifts. If the load was shifted to unknown non-Phase I units, the Agency proposed the use of a proxy for establishing an emissions rate, i.e., a current weighted average emissions rate for all non-Phase I units in the NERC region in which the Phase I unit was located. The Agency believed this to be a reasonable approach, considering that the NERC region was the most probable universe of sources from which compensating generation would be obtained.

Much of the public comment addressed issues concerning the allowance surrender formula and stated that the formula was confusing and unworkable as proposed.

Response: In light of these public comments, the Agency has determined that the basic approach in the proposal should be modified. Under the proposal, multiple Phase I units could claim compensating generation from a low-emitting, off system, non-designated unit. There would be no means of requiring all these units to agree on how to divide up such generation or of preventing double counting of such generation.

The final rule distinguishes compensating generation within a defined dispatch system from that provided from outside the dispatch system. Of course, a unit may adopt an expansive definition of its dispatch system. For a unit to be credited for compensating generation from a specific unit or sulfur-free generator (whether from within or outside the dispatch system), the compensating unit or sulfur-free generator must be designated. Otherwise, the unit surrenders allowances based on an appropriate weighted average emission rate. The total amount of underutilization for the dispatch system will be multiplied by an emissions rate that is the weighted average of the current dispatch system emissions rate and the 1985 NERC region emissions rate. These emissions rates are averages based on the emissions rates of Phase II units in the dispatch system and of non-foreign and non-Phase I units in the NERC region respectively. This is explained in detail below. The result is the number of allowances to be surrendered, reflecting certain adjustments for other Phase I units, dispatch system sales decline, and foreign sources.

(ii) Verification of compensating generation. Under the proposal, increased generation at designated compensating units in a utility system was counted in the Phase I aggregate utilization test for calculating the net underutilization of Phase I units in the system. Phase I units with underutilization would surrender allowances for their share of the net underutilization for the system. Under that approach, however, if there were more than one underutilization Phase I unit in the utility system, all such units would be credited with a portion of the generation at any designated compensating unit within that system. The Phase I unit that designated it would still surrender allowances based on its share of the net underutilization for the utility system. It was therefore necessary to devise a method whereby the Phase I unit designating a compensating unit would receive credit for all of the increase in generation at that compensating unit.

In the final rule, the designated representatives of the Phase I unit reducing its utilization and the compensating unit must certify that the amount of generation (in Kwhs) to be credited (after conversion to mmBtus based on the reducing unit's heat rate) to the reducing unit will be reflected (after conversion based on the compensating unit's heat rate) in calculating the utilization of the compensating unit. By adjusting each unit's utilization before determining net underutilization of the dispatch system, the designated compensating generation is attributed to the unit that designated it. This also prevents double counting of the compensating generation.

Compensating generation from sulfur-free generators designated by the reducing unit requires a different approach because these generators are not regulated under the Acid Rain Program. If a sulfur-free generator is in the same dispatch system as the reducing unit, then the reducing unit must demonstrate an increase in generation at that generator above any increase that resulted from sales growth in the dispatch system. This method essentially attributes all increases at the sulfur-free generator to the Phase I unit that designated it. If a Phase I unit has designated a sulfur-free generator outside of its dispatch system, the Phase I unit must, in addition, provide documentation showing that an amount of electrical energy at least equal to the amount of claimed compensating generation was actually purchased by the unit's dispatch system from the sulfur-free generator.

If the sulfur-free generator is providing compensating generation for more than one Phase I unit, inside or outside of the dispatch system, it is the responsibility of those Phase I units to claim in total only the amount of the increased generation at that sulfur-free generator and apportion that amount among themselves.

(iii) NERC-wide generation and emissions data. Under the proposal, NERC-wide information would have been used to calculate two factors in the allowance surrender formulas. First, the formulas used, as a proxy emissions rate, a current NERC-wide average emissions rate calculated using the annual average emissions rate for all non-Phase I units within a given NERC region. In addition, in response to industry input in the proposed rulemaking, it was agreed that there should be no allowance surrender to the extent that Phase I units might have compensated for a portion of the underutilization. In order to approximate this portion, a unit would establish what percent of its compensating generation came from unknown sources and what percent of total current NERC generation was produced by Phase I units. Multiplying the two percentages would approximate the fraction of emissions that should not be subject to allowance surrender. EPA requested comment on the feasibility of compiling this NERC-wide data for a given calendar year by the allowance transfer deadline for that year.

Several commenters stated that current, annual NERC-wide data could not be compiled within that time frame. Because of this problem, some commenters suggested that NERC-wide data for other periods (e.g., September 1–August 31 of the prior calendar year) be used.

Response: EPA now recognizes that, whatever period is used, it would be unduly burdensome to require that each unit calculate NERC-wide data on its own. Moreover, such an approach could well result in utilities within a given NERC region arriving at different calculations and data. To facilitate consistency within each NERC region, information for each region could be compiled by one impartial source. EPA considered acting as the clearing house for these yearly calculations. However, this approach was rejected as a result of experience gained in establishing baselines for the NADB. It has taken several years to resolve disputes over the data and publish final data.

In the final rule, the Agency has taken an approach that solves the timing, burden, and consistency problems. EPA has included in the rule the NERC-wide non-foreign and non-Phase I emissions rate and percent of non-foreign and non-Phase I generation for each NERC region for 1985, which are derived from the extensively reviewed, final data in the NADB. This NERC-wide data will be used to approximate the emissions resulting from, and therefore to determine the number of allowances surrendered for, compensating generation by units outside of the dispatch system. The methodology used to calculate these values is available in the docket.

(iv) Sulfur-free generators. Commenters requested that EPA expand the Phase I aggregate utilization test under the proposal to include non-designated sulfur-free generators in calculating net underutilization for the utility system.

Response: The Agency agrees in principle that there should be no allowance surrender to the extent that a unit can demonstrate that compensating generation was provided by a sulfur-free generator. Including sulfur-free generators when determining the net underutilization for the dispatch system would require a showing that such generators increased their generation above average annual 1985–1987 generation and after accounting for system-wide growth. In addition, designated representatives would be required to agree, before submitting their annual reports, on how to divide sulfur-free generation into designated and undesignated categories. These demonstrations would essentially duplicate those required at the end of the year where a plan is submitted. The burden of completing and submitting a plan designating a sulfur-free generator is minimal, and the plan can be submitted or activated any time at least 90 or 60 days respectively before the allowance transfer deadline. Therefore, to avoid unnecessary complexity in the rule and the implementation of the rule, the Agency requires in the final rule that to receive credit for increased generation at sulfur-free generators, a unit must designate the generators in the reduced utilization plan.

(v) Forced outages. The Agency wishes to clarify the confusion arising as a result of a typographical error in proposed § 72.409. Subsection (e) of proposed § 72.409 should have read, "To the extent the demonstrations required by paragraphs *(a)(1)–(2)* of this section do not account for the entire amount of unplanned underutilization," allowances must be surrendered consistent with the allowance surrender formula (emphasis added). Shifts in generation due to forced outage—like generation shifts resulting from economic dispatch—may result in increased SO_2 emissions at units not subject to the Acid Rain emissions limitations during Phase I and therefore must be subject to allowance surrender. This correction is reflected in the final rule.

Under the proposal, units would be required to submit information about every forced outage. This information included, but was not limited to, the cause of the outage, what steps were being taken to rectify the situation, and the extent of the underutilization that was attributable to that outage. Commenters claimed that the reporting requirements in the event of a forced outage were too burdensome.

Response: EPA is under a statutory obligation to require a Phase I unit to file a reduced utilization plan when the unit is shut down for purposes of compliance and so is underutilized. The Agency maintains that the reporting requirements in the event of a forced outage are necessary to prevent the circumvention of the section 408(c)(1)(B) planning requirement. For this reason, the information required under the rule to be reported concerning a forced outage is the same as in the proposed rule.

However, the Agency has modified the reporting requirements so that they apply to a smaller universe of forced outages. A given outage will trigger the reporting requirement only if the outage will be identified in the annual compliance certification report as a justification for unaccounted-for underutilization or if the outage is continuing and is expected to last longer than 4 months. This approach will reduce the reporting burden and provide information necessary to identify instances of potential circumvention. In all cases, underutilization resulting from a forced outage will be compensated for by allowance surrender according to the formulas in § 74.92.

(vi) Treatment of foreign generation. The preamble of the proposal stated that underutilization resulting in generation being shifted to foreign sources would be excluded from allowance surrender. However, the allowance surrender formulas did not actually deduct load from foreign sources in calculating emissions for which surrender was required. Therefore, in the proposal, the practical result would have been allowance surrender for these shifts.

The Agency requested comment on the treatment of foreign generation. Several commenters claimed that the intent of title IV is to regulate sources within the United States. Therefore, Phase I units that shift generation to foreign sources are allegedly under no obligation to surrender allowances for those shifts.

Response: The Agency believes that there should be no allowance surrender for shifts to foreign sources (i.e., Canadian sources), but for reasons different from those suggested in public comment. As a result of the U.S.-Canada

Air Quality Agreement, Canadian sources will be subject to an annual national sulfur dioxide emissions cap. If a Canadian source chooses to increase its output in order to sell to the U.S., it will have to account for those emissions in Canada. The resulting costs will presumably be reflected in the price the U.S. utility pays for the Canadian generation. Requiring allowance surrender by the U.S. utility would result in double counting of the costs of emitting SO_2 in Canada. Consequently, the final rule does not require allowance surrender for such shifts.

(7) Phase II Repowering Extensions

Repowering is the only optional compliance method available for compliance with sulfur dioxide emissions limitations during Phase II of the Acid Rain Program. A repowering extension provides a qualifying utility the extra allowances needed to cover its emissions during the time required to install a qualified repowering technology. Congress created this extension to encourage certain types of new, innovative clean coal technologies.

In § 72.44 of the final rule, the Agency has clarified certain provisions and some inconsistencies between the proposed rule and preamble. While many comments were received concerning the repowering extension, they addressed the same issues and presented many of the arguments discussed in the proposal. As a result, the Agency made few substantive changes to the original proposal.

(a) Definitions. (i) "Qualifying repowering technology". According to the proposal, a "qualifying repowering technology" must involve boiler replacement. While most commenters addressed this issue, they presented the same arguments as those discussed in the preamble of the proposed rule.

Response: EPA still maintains that the statute clearly mandates boiler replacement as a prerequisite for approval as a qualifying technology. The Agency reiterates that the failure to qualify for a repowering extension does not preclude a utility from employing a clean coal technology or other method of complying with Phase II emissions limitations.

(ii) "Replacement." In the proposal, the Agency stated that it would determine whether a technology involved boiler replacement on a case-by-case basis, using the test in 40 CFR 60.15 for "reconstruction" as general guidance. EPA requested comment on this approach. Several commenters objected to the proposed 40 CFR 60.15 test—which requires that new components cost over 50 percent of total cost to construct a comparable new facility—as too strict for innovative technologies. Other commenters claimed that the 40 CFR 60.15 test is not strict enough because it would not require 100% boiler replacement.

Commenters from environmental groups and one utility agreed with the Agency's proposed definition. They argue that the broader the definition of repowering, the greater the number of allocated bonus allowances breaking the 8.95 million ton cap during 2000–2010 and the larger the ratchet reducing non-repowering units' allowance allocations in Phase II.

Response: The Agency continues to believe that a case-by-case approach is warranted by the complex and intensely factual nature of the determination of whether a technology involves boiler replacement. Moreover, the 40 CFR 60.15 test strikes a balance between an overly broad interpretation that would increase overall emissions and an overly narrow interpretation that would limit the incentives under section 409 of the Act for innovative technology, and the test will therefore be used as guidance.

(b) Treatment of failed projects. The proposal mirrored section 409(b)(2) of the Act, which provides that if the repowering technology has been properly constructed and tested on such unit but fails to meet emission reduction limitations and is economically or technologically infeasible, the unit will continue to receive its extension allowances. This would permit the unit to be retrofitted or repowered with another control technology. Once the extension ended on December 31, 2003, the repowered unit would be limited to the standard Phase II allowance allocation. The Agency requested comment on the treatment of repowering projects that fail before they are completed and tested and whether and under what conditions a unit that did not complete construction should continue to get extension allowances.

Those commenters who maintained that a unit need not complete construction in order to continue to get such allowances suggested that, based on legislative history, EPA has the discretion to grant utilities extension allowances when a technology falls, or a utility decides to terminate the project, before construction and testing is completed. Commenters argued that EPA should use this discretion to allow utilities to continue to receive extension allowances when there has been a good faith effort to try to complete a project. Otherwise, these utilities would be forced to spend large sums of money to finish the project, which is doomed to failure, in order to receive the allowances.

Response: The Agency believes that "proper" construction and testing to determine if a project has failed does not necessarily require "completion" of construction. Thus, consistent with the legislative history, EPA has discretion to make case-by-case judgments of whether there was proper construction and testing of a given project. However, because repowering extensions will break the Phase II emissions cap, the Agency is under a statutory mandate to be frugal in granting the full repowering extension where the repowered unit is not completed. The final rule provides that to be considered properly constructed and tested, the project must be constructed at least to the extent to permit direct testing of the multiple combustion emissions from the operation of the repowering technology at nameplate capacity.

(c) Treatment of unused allowances. While section 409(c)(1) of the Act states that allowances are not transferable to any other source, this does not preclude a unit from transferring unused allowances to another unit at the same source. However, several commenters believe that a unit granted repowering extension allowances cannot transfer those allowances to any other units and should be required to return any unused extension allowances.

Response: Extension allowances are transferable between units at the same source. Nothing bars a transferee from transferring any allowances, freed up by that transfer, to other units at any source. Because there is no express statutory authority for EPA to require the surrender of unused allowances and any surrender requirement could be so easily circumvented, the Agency has rejected the commenters' approach.

However, the Agency has clarified the meaning of the bar on transferring allowances to other sources. The final rule bars the transfer of the extension allowances to any Allowance Tracking System account other than unit accounts of other units at the same source. Since allowances cannot be used for compliance unless they are recorded in the Allowance Tracking System, the bar on transfers should focus on transfers among Allowance Tracking System accounts. The language in the final rule will prevent direct use of the extension allowances by units at other sources.

(d) Repowering application deadlines. Section 403(a) of the Act requires the Agency to issue final Phase II allowance allocations (reflecting repowering extension allowances) by June 1, 1998. Under section 408(d), the Phase II

permit application, including the repowering extension, must be submitted by January 1, 1996 and the Phase II permit must be issued by no later than December 31, 1997. Under section 409(a), the owner or operator of an existing unit must demonstrate by December 31, 1997 that it meets the requirements for a repowering extension. Reflecting these constraints, EPA proposed a January 1, 1996 deadline for submitting the repowering extension plan. If conditional approval was sought, the approved plan could be activated any time on or before December 31, 1997. Further, the proposal sets a June 1, 1997 deadline for submitting the petition for approval of a repowering technology in order to allow the Agency 6 months to review and act on the petition before the December 31, 1997 deadline for action on the permit application. The Agency requested comment on the proposed deadlines. Several commenters claimed that certain non-statutory deadlines in the proposal were not justified.

Response: The Agency maintains that the proposed deadlines are consistent with the statute and necessary for the smooth and timely implementation of the repowering extension. In particular, if the repowering technology petition were not submitted until the end of 1997, the statutory deadline for permit issuance would be missed. For these reasons and the reasons stated in the preamble for the proposal, the deadlines are retained in the final rule.

(8) Acid Rain Permit Application and Acid Rain Permit (Subparts C and E)

Under section 408 of the Act, the designated representative of each affected source must submit a permit application, including a compliance plan that sets forth the methods to be used to comply with the requirements of the Acid Rain Program. The permitting authority reviews such applications, approves or disapproves the compliance plans, and issues or denies permits.

a. Permit application information available from other data sources. In the preamble to the proposed rule, EPA requested comments on whether the Agency should request information that could be obtained from other data sources. Commenters agreed that EPA should require all the information needed to issue the permit to be submitted on one permit application form, rather than attempting to obtain this information from other data sources.

Response: The Agency therefore will require all needed information to be submitted by the applicant. The Agency has, however, attempted to simplify and clarify the information requirements for the permit application. The final rule asks only for the information that is needed to write the permit; the Agency will not ask for extraneous information. The Agency believes that having clear and simplified permit application requirements will facilitate compliance by all affected units.

b. Data no longer required in permit application. (i) Project annual utilization. Several commenters objected to the requirement to provide projected annual utilization, as reported on EIA form 767, for units covered by the permit application. They pointed out that EIA form 767 data will not be available at the time the permit applications are due and will not provide all of the required projections. Furthermore, commenters questioned what EPA would do with the information.

Response: The Agency has reconsidered the need for this information and decided that there was no statutory basis for requiring that these projections be met. The Agency has therefore deleted this requirement as being unnecessary and burdensome on the regulated community.

(ii) Most stringent federally enforceable emissions limitation. Several commenters objected to the fact that EPA was requiring the most stringent federally enforceable emissions limitations to be annualized (in accordance with a formula used in the NADB) and provided on the permit application. Commenters claimed that this was an inappropriate use of annualization factors.

Response: The Agency has reconsidered this information requirement and determined that it is not necessary. While under the proposal the information was necessary for substitution plans and Phase I extensions plans, the Agency has decided not to use the information in the case of substitution plans and has limited its use in Phase I extension plans. The reasons for the changes are discussed in the preamble sections of these plans. There is no need to require this information for all units. Further, while holding allowances under the Acid Rain Program does not exempt a unit from the requirement to comply with any other applicable limitation under the Act, the Agency believes that the Acid Rain permit application is not the appropriate place to record other limitations. Operating permits issued under title V will address the requirements of other programs.

(iii) Monitoring information. The Agency received several comments on the proposed requirement to submit certain monitoring information with the permit application, including the monitoring plan and the monitoring certification. Some commenters supported this provision, arguing for concurrent review of the application and the monitoring plan. Others argued that no formal approval of the monitoring plan should be required and that the timing of submitting monitoring plans nine months before monitor certification is due would be burdensome on sources.

One commenter was also concerned that if monitoring plans and monitor certifications became part of the permit, the permit would need frequent revisions as changes to the monitoring plan were made and as monitoring recertification became necessary. Instead, the commenter recommended that EPA allow the source to certify that it will comply with the monitor certification requirements in part 75.

Response: In the final rules, the Agency is not requiring that any monitoring information be submitted with the permit application. This decision is motivated principally by the timing of the permit application and monitoring requirements. In Phase I, permit applications are due February 15, 1993 (see section 408(c) of the Act), while monitors need not be certified until November 15, 1993 (section 412(b)). The Agency believes that it would be unnecessarily burdensome on sources to require monitoring submissions to be made so long before monitor certification is required. The timing problem is reversed in Phase II, where monitors must be certified by January 1, 1995 (section 412(c)) but permit applications are not due until January 1, 1996 (section 408(d)(2)). For the same reasons, the Agency has also deleted the requirement that monitoring plans and monitor certifications be a part of the permit. Instead, each Acid Rain permit will contain a standard requirement that the source must comply with part 75 (see § 72.9(b)(1)). Thus, a violation of any requirement in part 75 will be a violation of the permit (see the portion of the preamble for part 75).

(c) Conditional approval of compliance plans. (i) Enforceable milestones. Section 72.40(c) (proposed § 72.32(g)) allows sources to obtain conditional approval for compliance options. Thus, when the source submits its application, it may submit one or more compliance options for conditional approval. These compliance options will go through public notice and comment with the proposed permit. They will be approved conditionally, and the source may activate the options

by notifying the Agency. The activation of a conditionally approved compliance option is an administrative amendment.

One commenter objected that the provision that compliance options are not effective until activated by the designated representative could be used to evade the Act's requirement for enforceable compliance schedules for sources that employ certain optional methods of compliance. The commenter stated that a source that intended to rely on an optional method of compliance could identify the proposed method as conditionally approved and thereby prevent enforcement of interim milestones in its approved compliance schedule for that option by failing to activate the option until after the milestones have passed.

Response: The Agency believes that such a situation is not likely to occur. However, the Agency does not want to allow conditional approval to be used as a vehicle to escape from otherwise enforceable requirements. The Agency therefore has included a provision in the final rule that states that compliance options with enforceable interim milestones must be activated prior to the interim steps set forth in the compliance option or else not activated at all.

(ii) Notification of activation. Another commenter stated that EPA should not require notification of activation of a conditionally approved compliance option since the option has already been reviewed and approved by the Agency.

Response: The Agency disagrees. EPA needs notification of activation of the conditionally approved compliance option in order to modify the allowance allocations based on the compliance option. For example, the source may have a conditionally approved substitution plan; upon activation, the Phase II substitution unit becomes a Phase I unit eligible for allowances. Unless EPA receives notice, it cannot allocate allowances to the unit. In fact, because of the need to amend the unit's permit and allocate allowances, the final rule clarifies that conditionally approved substitution or reduced utilization plans must be activated no later than 60 days before the allowance transfer deadline applicable to the year in which the plan is to take effect. However, the notice does not give the Agency the opportunity to revisit the merits of the previously approved compliance option.

The need for notification is amplified where the conditionally approved compliance option involves two or more units that have different designated representatives. Under such circumstances, the compliance option cannot be implemented unless all the designated representatives agree to the activation. The prior notification requirement ensures that all the designated representatives will be aware of, and act in accordance with, the activation. Moreover, the final rule clarifies that all designated representatives of units involved in the compliance option must sign the activation notice.

(d) Interaction between permit and compliance plan. In the proposal, EPA asked for comment on whether compliance plans should be included in the permit (and possibly renamed "alternative operating scenarios") or should remain separate documents that are incorporated in the permit by reference to the compliance plan. There was no consensus among the commenters who addressed this issue, and none addressed the renaming issue. All of the commenters, however, were concerned with ensuring that sources have the maximum flexibility possible to make minor operational changes without being subject to a time consuming permit revision procedure.

Response: On reconsideration, the Agency believes that there is no practical or legal difference between including the compliance plan in the permit and treating the compliance plan as a separate document incorporated by reference in the permit. The Agency is adopting the approach of treating the compliance plan as part of the permit in order to make it clear that the plan, like the other permit provisions, is binding. Since the Act uses the term "compliance plan" and no commenters expressed any interest in changing the term used in the regulations, the final rule continues to use the statutory term.

(e) Permit shield. The permit shield provisions in proposed § 72.53(b) were supported by some commenters and opposed by others. Supporters stated that the permit shield would provide affected sources with certainty that compliance with the terms of the permit would shield the source from enforcement action. Opponents objected that the proposed shield was too narrow because the shield would not apply unless the permit conditions were clearly in compliance with title IV and the Acid Rain Program.

Response: EPA has retained in its final rule language similar to that in the proposed permit shield. The language in the proposal and in the final rule is very similar to the language in section 408(h)(2) of the Act, which provides that compliance with a permit issued under title V *which complies with this title* for sources subject to this title shall be deemed in compliance with the requirement to operate in compliance with an operating permit.

However, the Agency modified the language in the permit shield to clarify it and make it consistent with provisions, originally in the proposal and retained in the final rule, concerning the liability of the owners and operators of units involved in multi-unit compliance options or units with a common stack. Under these provisions, the owners and operators of one such unit are liable for violations of the plan by the other units. The permit shield in the final rule specifically refers to these provisions in order to clarify that such owners and operators continue to bear such potential liability. As discussed above, EPA's enforcement efforts will focus on the truly culpable parties.

(9) Federal Permit Issuance Procedures (Subpart F)

Under section 408 of the Act, EPA is the permitting authority in Phase I and, for geographic areas not covered by an approved State operating permit program, in Phase II. As the permitting authority, EPA is responsible for review of permit applications and issuance of permits. Section 408 requires EPA to develop regulations to establish permit issuance procedures.

(a) Denial of permit application. The Agency deleted proposed § 72.61(c)–(e) although these provisions do not appear elsewhere in the rules. These provisions concerned the denial of Acid Rain permit applications and Acid Rain permits and the procedure for correcting denied applications.

Response: The Agency believes that these sections are unnecessary and merely add confusion to the permit issuance process. The proposed and final rules already provide that if an application is incomplete, the Agency will issue a notice of incompleteness. Further, under these rules, the Agency may request supplemental information even where the application is complete. Moreover, where the permit application fails to meet the requirements of the Act, the Agency may issue a draft permit (called a "proposed" permit in the proposal) that disapproves compliance options requested in the permit application or may deny a draft permit. The Agency will provide a statement of basis explaining its action. In all of these circumstances, the designated representative may make necessary changes to the permit application. Thus, the Agency deleted the provisions in the proposal addressing denial and correction of permit applications and denial of permits because the provisions

duplicated, and to some extent contradicted, procedures already provided in the rule.

(b) EPA approval/denial time frame. One commenter objected to proposed §72.70(b)(3), which stated that even though an application was deemed complete, the 6-month period for EPA action on the application would not begin to run where the designated representative subsequently failed to submit any requested supplemental information in a timely manner. The commenter stated that this provision is inconsistent with section 408(c)(2) of the statute, which requires EPA to act on compliance plans within 6 months and with proposed § 72.72(b)(2)(ii), which states that failure to provide supplemental information shall result in a denial of the permit.

Response: The Agency agrees that proposed § 72.72(b)(3) was inconsistent with the Act and has therefore deleted the provision. Under the final rules, where an applicant fails to submit supplemental information in a timely manner, the portion of the permit for which the information was necessary may be denied.

(c) Criteria for completeness. Several commenters requested that EPA clearly state the criteria it will use to determine whether a permit application is complete.

Response: The Agency reviewed proposed § 72.72(b)(3), which simply repeated or cross-referenced the requirements for permit applications. In the interests of clarity, the Agency has deleted this section and amended §72.31 to set forth the information required in a "complete"permit application. The Agency believes that the information requirements set forth at §72.31 are clear and straightforward and that sources will not have difficulty understanding and complying with the requirement to submit a complete application. In addition, the Agency will publish standard application forms that the sources can use. These forms, if filled out completely, will help ensure that the source submits a complete application.

(d) Proposed permits binding on a source. One commenter objected to proposed § 72.73(e), which makes proposed permits (called "draft" permits in the final rule to be consistent with the part 70 regulations under title V) binding on the source until a final permitting decision is issued. The commenter argued that "it would be extraordinarily unfair to impose on any source the terms of a mere proposed permitting decision that has not been subjected to proper procedures to ensure consistency with the Act." The commenter also stated that there is no statutory support for making the proposed permit binding on the source.

Response: The Agency agrees. Upon reconsideration of this issue, the Agency believes that a draft permit (formerly called a "proposed permit") should not be binding on the source since such a permit has not yet gone through notice and comment procedures giving the applicant and other parties the opportunity to address its consistency with the Act and with Agency policy. The Agency, therefore, has eliminated the requirement that the draft permit be binding on the source in lieu of a permit until the permit is issued. Instead, a complete permit application and compliance plan will be binding on the source until a permit is issued, as provided in section 408(c)(1)(A) and (d)(3) of the Act.

(e) Public comment period. (i) Permits and monitoring plan. EPA received several comments on the public comment provisions of its proposal. Several commenters supported the public comment provisions as proposed, but recommended that EPA allow comments on monitoring plans during permit review to minimize the possibility of redundant public comment periods.

Response: The Agency agrees that redundant public comment periods are a waste of time and resources for the Agency, the public, and the affected source. However, as discussed above, the final rules eliminate the requirement for a monitoring plan as part of the permit because of timing differences between permitting and monitor certification. Thus, in general, there will be no reason to make comment on the monitoring plan in the context of permit review.

(ii) Need for public comment. One commenter suggested that EPA eliminate the requirement for a public comment period for Acid Rain permits. The commenter states that utilities will either purchase allowances, add controls, or switch fuels and that since the Act gives sources the choice of which option to pursue, there is no need for public comment.

Response: The Agency disagrees. Section 408(a) of the statute mandates that title IV be implemented by permits issued in accordance with title V, as modified by title IV. A fundamental requirement of title V (set forth in section 502(b)(6)) is provision of an opportunity for the public to comment on the proposed permit. Furthermore, title IV gives sources the opportunity to request certain optional methods of compliance, such as substitution, Phase I extension, repowering extension, and reduced utilization plans. Before the Agency approves these optional methods of compliance, the public should have an opportunity to comment on the source's proposal and whether it meets the requirements of the Act. In addition, the comment period gives the source an opportunity to object to the draft permit that EPA proposes to issue in final.

(f) Fast-track modifications. (i) General. The Agency received numerous comments supporting the fast-track modification approach. Commenters supported promulgating Option 1, Option 2, or both. Several of the commenters who supported both options, however, stated that if EPA were to promulgate only one, it should promulgate Option 2. Several commenters who supported Option 1 also requested clarification from EPA on what it meant by "significant objections" to a fast-track modification that would require the source to shift to the regular modification procedure. The Agency received comments from environmental groups stating that they need at least 30 days to comment adequately on permit conditions.

Response: The Agency considered all of these comments and determined that Option 2 best addresses the concerns of the commenters. Option 1 provides only 15 days for public comment while Option 2 provides 30 days. The Agency believes that it is critical that interested persons be given an opportunity to comment adequately on significant changes in permit conditions. Option 1 does not allow adequate opportunity for comment. In addition, the Agency believes that proposed Option 1 could prove to be less expeditious than Option 2. Option 1 requires that the permit modification procedures be followed if significant objections are received during the 15-day comment period. Thus, to effect the change, two different permit revision procedures might have to be implemented. Under Option 2, there is a 30-day opportunity for comment. The Agency then has 30 days to review and act on the application and all comments. In many cases, Option 2 will prove to be more expeditious. For these reasons, the Agency has decided to promulgate only Option 2 in its final rule and clarify that fast-track procedures may be used, for any of the listed revisions, at the option of the designated representative submitting the permit revision.

(ii) Notice to interested persons. Numerous commenters also stated that, as proposed, only people who commented on the proposed permit would receive written notice of a fast-track modification. These commenters

objected to this limitation, stating that any person who asked to be put on a mailing list should receive notice of any fast-track modifications. One commenter pointed out that this limitation was inconsistent with proposed § 72.77 (public comments), which allows interested persons to put their names on a mailing list at any time and to receive notice of future actions affecting that permit.

Response: The Agency agrees with these commenters and has clarified in the final rule that written notice must be given to any interested person. Under § 72.2, an interested person is someone who either comments on the draft permit, testifies at a public hearing on a draft permit, or requests to have his or her name put on a mailing list to receive notice of any future actions on that permit.

(g) Minor permit modifications. In the proposal, the Agency asked for comment on whether some of the changes to the permit that were proposed as modifications or fast-track modifications could be accomplished using the minor permit modification (originally referred to as "minor permit amendment") procedure proposed in part 70 of this chapter. The Agency received several comments on this issue. One commenter agreed with EPA that the fast-track modification will be expeditious enough for approval of a new compliance option. Several other commenters stated that permit revisions should not be required for replacement of equipment but implied that if a revision were required, the minor permit modification would be appropriate.

Response: The Agency is not requiring notification or a permit revision for changes to equipment. In fact, permits will not include detailed information about how the source is going to operate or comply unless the source applies for an optional method of compliance. For example, if a source initially chooses to comply by switching to low sulfur coal but decides in 1997 to install a scrubber, neither the initial compliance decision nor the change will be included in the permit. This is because these approaches do not require approval of an option compliance method but rather require only that the source undertake to hold sufficient allowances to cover its emissions. Thus, the minor permit modification procedure is not needed for these types of changes. Moreover, since no commenters recommended that changes now covered by fast-track modifications be accomplished using the minor permit modification procedure, the Agency has decided not to promulgate a minor permit modification for changes to Acid Rain permits. The Agency believes that this revision procedure is unnecessary for the Acid Rain Program because the program requires notification only of changes in compliance options and of certain relatively minor permit changes, which can be accomplished through fast-track modifications and administrative amendments respectively.

(h) Administrative amendments. Generally, commenters supported the Agency's proposed administrative permit amendment provisions. These commenters believed that the changes included in this section could be accomplished without public notice and comment.

Response: The Agency agrees and has eliminated the requirement in the proposed rule that notice be given to interested persons of every administrative amendment to the permit. The Agency believes that interested persons should have access to current information about changes in permits and permit conditions. However, the Agency does not believe that the burden of providing notice is justified in this case because administrative permit amendments are relatively minor or noncontroversial and become effective without any opportunity for public comment. One example of such an administrative amendment is the adoption of or a change in a reduced utilization plan that does not involve designation of a compensating unit (e.g., a plan relying on energy conservation or sulfur-free generation). The Agency notes that the permits will be publicly available at EPA Headquarters and the Regional Office in the region where the source is located. In Phase II, permits will also be available at the office of the State permitting authority.

(10) State Permit Program Approval Criteria (Subpart G)

Under section 408(d) of the Act, each State must submit, for EPA's approval, a permit program, in accordance with title V, under which the State will issue Acid Rain permits for Phase II. The permit program must meet certain criteria in order to be approved by EPA. If the State program is approved by July 1, 1996, EPA will cease issuing Phase II Acid Rain permits. Under title V, State permit programs must also meet criteria concerning, and provide for, issuance of operating permits implementing other requirements of the Act in addition to those under title IV. The permit programs must be submitted by November 15, 1993.

(a) Complexity of acid rain program requirements. Some commenters were concerned about the complexity of the proposed Acid Rain regulations and the effect that complexity would have on States' ability to develop their permit programs under title V by the statutory deadline of November 15, 1993. One commenter suggested that EPA review separately State submissions under title V and title IV and give States longer to develop and submit their title IV permit programs.

Response: EPA believes that adoption of the commenter's suggestion is not warranted at this time. Both section 408(a) and section 502(a) of the Act require that title IV be implemented through title V, as modified by title IV. Thus, the Acid Rain Program will be an integral part of a State's title V operating permit program. Furthermore, the Agency believes that State regulations needed to implement the Acid Rain Program will not be particularly complex since many of the more complex aspects of the program (e.g., allowance allocations) will be implemented by EPA. The Acid Rain portion of the title V operating permit will be considerably less complex than the portion implementing the State implementation plan (SIP) and other requirements of the Act.

(b) Interference with allowance market. The Agency received numerous comments on proposed § 72.202(a), which bars a State operating permit program from interfering with the allowance market. The majority of the commenters supported § 72.202(a) as proposed, saying that State interference with the allowance program would frustrate a crucial objective of title IV: The achievement of nationwide emissions reductions at the least cost to utilities. However, a significant minority of the commenters opposed this section, claiming that it would limit a State's ability to protect legitimate interests, such as limiting the total deposition within the State and protecting national parks and forests.

Response: The Agency has retained this provision in its final rules. The Agency believes that these restrictions on State action are necessary to ensure that a national allowance market has an opportunity to develop and that sources are allowed to comply with the Acid Rain Program in the most cost-effective manner possible. The Agency realizes that States have a legitimate interest in protecting ambient air quality and that they therefore may want to limit emissions by restricting allowance trading. Nonetheless, the Acid Rain Program is a national program designed to reduce substantially total national

loadings of acid deposition precursors. The national transfer of allowances was clearly contemplated by the drafters of the Act. Geographical limitations on allowance transfers were included in early Senate and House versions of the bill, but later rejected in favor of national transfers. Congress was aware that failure of a nation-wide allowance market would create significant problems for new power plants (particularly those constructed by independent power producers) that are not allocated allowances by EPA but must purchase enough to cover their emissions. Report of the Committee on Energy and Commerce, House Report No. 490, at 366–67 (1990). In fact, prior versions of the bill that became the Clean Air Act Amendments of 1990 divided the country into two regions and permitted allowance transfers only within those regions. That restriction was removed in the final bill. See, e.g., *id.* at 372. Moreover, the active trading of allowances will enable utilities to adopt the least-cost approach to achieve their required SO_2 emissions reductions. The allowance market would likely fail if State or local permitting authorities had the ability to restrict the transfer of allowances.

Furthermore, under the Act, States have authority to protect local air quality concerns through requiring compliance with the SIP and with applicable National Ambient Air Quality Standards, rather than through restrictions on allowance trading. Section 403(f) provides that compliance with the Acid Rain Program will not excuse compliance with other applicable Clean Air Act requirements. The Agency realizes that a SIP will not allow a State to influence compliance decisions of utilities in neighboring States, which may have less stringent emissions requirements in their SIPs, and that emissions may travel across State lines and affect air quality or acid deposition in other States. Nonetheless, States had limited authority to influence compliance decisions of sources in neighboring States prior to enactment of the 1990 Amendments to the Clean Air Act, and the Agency does not believe title IV was intended to expand such authority. If Congress had intended to expand States' authority in this regard, it would have expressly said so.

(c) EPA intervention in appeals. Section 72 .202(i)(3) of the proposed rule required that the Administrator be given authority to intervene as a matter of right in any State administrative or judicial permit appeals involving an Acid Rain permit provision. This provision was proposed in order to ensure national consistency in State interpretations of Acid Rain permit requirements. One commenter considered this provision too intrusive on the rights of States to administer a delegated title V program.

Response: The Agency agrees only in part. For the rest of the title V program, EPA's oversight role through review and possible veto of permits will suffice. However, national consistency is needed in the Acid Rain Program more than in the rest of the title V program in order to ensure that a national allowance market has an opportunity to develop. To ensure that States do not adopt inconsistent interpretations of Acid Rain provisions that would adversely affect the allowance market, the Agency must have the opportunity to participate in State proceedings affecting Acid Rain permits. When there is an administrative appeal of an Acid Rain portion of a title V permit, there is a chance for inconsistent interpretations of Acid Rain provisions. The Agency needs to be assured that it will have an opportunity, before such interpretations are adopted, to present its interpretation of the Acid Rain Program in any State administrative appeal of an Acid Rain permit. However, by intervening in the State administrative proceeding, EPA may participate as a party in any subsequent State judicial appeal. In the unlikely case that EPA has no involvement until the judicial appeal, the Agency believes the courts will likely permit its participation as an *amicus*. Thus, the final rule requires a right of intervention only in State administrative appeals.

(11) Compliance Certifications (Subpart I)

Proposed subpart K, renamed subpart I in the final rule, described the compliance certifications that the designated representative would need to submit for each affected unit.

These compliance certifications included: Quarterly reports concerning emissions data and quality assurance information and the unit's compliance status with regard to deadlines and increments of progress; and annual reports concerning the requirement to hold allowances not less than total annual emissions, to submit a reduced utilization plan and surrender allowances for underutilization of Phase I units, and to meet nitrogen oxides emissions limitations. In addition, there were a number of periodic certifications required under the various compliance options.

Simplification and Reduction of Burden

A number of commenters found the subpart to be confusing in general and claimed that there was a need to reduce the regulatory burden imposed by the certification requirements.

Response: The Agency has endeavored to simplify and clarify the certification requirements and reduce the regulatory burden, while recognizing that compliance certification plays an important role in the Acid Rain Program. First, the annual requirements that all units certify to their total tons of emissions for the year and the total number of allowances held in the unit's compliance subaccount as of the allowance transfer deadline have been deleted. The Agency will already get quarterly emissions data from the units and will keep track, on an ongoing basis, of the allowances in each unit's account. There is no need to require submissions duplicating this data.

Also removed are the requirements to file quarterly certifications of each unit's compliance status with regard to scheduled deadlines or increments of progress (proposed § 72.401), periodic certifications to change certain deadlines under specified compliance options or to give notice of the failure to meet certain deadlines and reporting or submission requirements (proposed § 72.403), and certifications of any nonscheduled event that affects compliance (proposed § 72.403).

Annual Compliance Certifications and Other Submissions

In contrast to the proposal, the final rule requires each unit to provide annual and quarterly compliance certifications limited to certain key aspects of the Acid Rain Program. The annual compliance certification report must include certifications concerning the requirements to meet Acid Rain emissions limitations, maintain an up-to-date monitoring plan, and monitor and account for all emissions. Any changes in the facts that form the basis for monitor certification or for using excepted or alternative monitoring methods must be certified. In addition, quarterly submissions of monitoring data are still required under 40 CFR part 75. These submissions must be accompanied by a certification that the data was obtained or derived as required under part 75. (See § 75.64(c)). These certification requirements are consistent with the certification requirements under part 70 of this chapter.

Finally, some reports related to specific compliance options are retained in the final rule. Submissions concerning reduced utilization and the surrender of allowances are required. (The comments addressing those submissions are addressed above in the portion of the preamble on reduced

utilization). Only those periodic reports that the Agency found to be necessary to administer Phase I extension plans and repowering extension plans are still required. Some new information for which a periodic report is no longer required still requires a permit revision (e.g., to change the date of commencement of operation of qualified Phase I technology). See § 72.83 (administrative permit amendment).

The Agency believes that reducing the number, and clarifying the information requirements, of reports and certifications in this way will reduce the regulatory burden while meeting the statutory compliance certification and reporting requirements of title V that are applicable to title IV. Section 504(c) of the Act and the part 70 regulations implementing title V require compliance certifications at least annually that contain statements of the methods of determining compliance, such as monitoring, recordkeeping, and reporting requirements and test methods. See 40 CFR 70.5(c)(a). However, under the Acid Rain Program, unlike other programs under the Act, the Agency already receives a large volume of highly reliable data on unit operation, emissions, and monitor calibration. Consequently, the scope of compliance certification needed under the Acid Rain Program is less than under other programs under the Act and can be limited to what is set forth in the final rule.

IV. Discussion of Changes to Part 73—Allowance System

There are three main structural changes to part 73. First, the definitions are being moved to part 72. All definitions for the Acid Rain Program will be in part 72. Second, in subpart D, § 73.52 Submission of Transfers was merged with § 73.50 Scope of Transfers. Finally, also in subpart D, § 73.55 Non-Recordation of Transfers was merged with § 73.53 Notification. In addition, §§ 73.3 (Definitions) and 73.4 (Deadlines), which were previously published with subpart E—"Auctions, Direct Sales, and Independent Power Producers Written Guarantee", on December 17, 1991, pages 65592–65607, are recodified at §§ 72.2 and 72.12, respectively. This recodification is being performed in order to locate all the definitions for the Acid Rain Program in one place, solely for the ease and convenience of the reader. In addition, the definitions that are being recodified were already subject to notice and comment under subpart E of this part. Any changes made to the definitions were made to reconcile all the provisions of the Acid Rain Program and are not for the most part substantive changes. To the extent that there are any substantive changes, these changes were made in response to public comment on the definitions under other proposed subparts of the Acid Rain Program rules (since in many cases the same definitions appeared in various different subparts of the rules). Thus, EPA finds that for all these reasons, additional public notice and comment on this recodification is impracticable, unnecessary, and contrary to the public interest, pursuant to 5 U.S.C. 553(b)(B), 42 U.S.C. 7607(d)(1).

This section of the preamble discusses the four issues that were of most interest to the public, a number of additional significant issues, and any changes made to the rule as a result of comments on these issues. The section also clarifies the procedure EPA will use to return proceeds from the auction and direct sale to each unit. Other issues and comments are addressed in the Response to Comments Document.

On July 7, 1992, EPA proposed the Phase I allowance allocations; Phase I Extension Reserve, and establishment of the Special Allowance Reserve (57 FR 29939). To facilitate trading and Phase I compliance planning, as well as the first auction of allowances from the Special Allowance Reserve, EPA is choosing to finalize the Phase I allocations and reserves today, rather than promulgate them with the rest of the Phase II allocation rules. Only one comments was received on the Phase I allocations, and EPA has modified the allocations for the Sunbury plant in response to that comment. Five comments were made regarding the calculation of the Phase I Extension Reserve. Four of the comments supported EPA's calculation methodology and one requested a modification. EPA has chosen to maintain its calculation methodology and discusses the requested method in the docket. No comments were received on the establishment of the Special Allowance Reserve for the Phase I period, so the proposed language has been adopted.

A. Allowance Transfer Deadline

The "allowance transfer deadline" is the last day on which allowance transfers may be submitted to EPA for recordation in a compliance subaccount for use in meeting a unit's SO_2 emissions limitation requirements for the year. EPA proposed to establish January 30 of the calendar year following the year for which compliance is being established as the "allowance transfer deadline."

EPA received a total of 122 comments on the issue of the allowance transfer deadline. The majority of commenters requested a 45-day (or February 14) allowance transfer deadline. A significant number of commenters supported at least the proposed January 30 deadline, a few commenters requested a 60-day (or March 1) deadline, and some commenters supported a December 31 deadline. Those supporting a December 31 allowance transfer deadline claim that an allowance transfer deadline after December 31 establishes a bad precedent for a market-based program. They believe that companies should be able to plan for the transfers needed for compliance well in advance of December 31, and thus should not need an extended deadline. They also believe that companies should maintain prudent contingency reserves to allow them to meet the requirements on December 31. In addition, the commenters are concerned that such an extension or "book closing period" is inconsistent with the intent of the Act and its enforcement and compliance provisions. Finally, they believe a January 30 deadline makes it difficult to complete the steps required for development of excess emission offset plans, due by March 1, on a timely basis.

Other commenters felt that the proposed 30-day, or January 30, transfer deadline is appropriate. They argue that 30 days are needed to provide units with sufficient time to transact and submit allowance transfers. They also comment that the January 30 deadline affords units one month from the submission of transfers to complete and submit excess emissions offset plans, if necessary, and EPA one month to record final transfers and resolve any associated errors.

The commenters supporting a 45-day, or February 14, allowance transfer deadline state that such a deadline is in line with Congress' intent and has no effect on the emission reduction goals of the program. In addition, they argue an extra 15 days will result in fewer transfer errors, and reduce the likelihood that any utility will actually be out of compliance and have to file an excess emission offset plan. Commenters supporting a longer transfer deadline also claim that EPA should not need 30 days after the transfer deadline for recording allowance transfers and handling claims of error, especially with an electronic Allowance Tracking System. They argue that additional time for compliance procedures is important for small utilities that do not have the staff or

expertise to promptly complete their compliance certification reports and locate allowances, if needed. A number of utilities commented that extending the transfer deadline by 15 days still leaves them enough time to prepare and submit their excess emission offset plan by the statutory deadline of March 1. Finally, they claim that allowing more time to negotiate allowance transactions for compliance helps minimize the overall compliance costs of the program.

A number of commenters favored a January 30 or February 14 allowance transfer deadline for its accommodation of utilities in power pools or those seeking to create allowance pools. For such power and allowance pools, they argue an extended allowance transfer deadline would enable member units to arrange for allowances to be transferred after the designated representatives have fully collected and assessed the final emissions data for the year on a system-wide or pool basis. At that point, since compliance is determined on a unit-by-unit basis rather than on an aggregate basis, surplus allowances from certain units could be transferred during the extended allowance transfer period to any units in the pool that needed them. These commenters assert that a December 31 transfer deadline, coinciding with the calendar year compliance requirements mandated by the Act, could inhibit the creation and operation of such power and allowance pools.

Several commenters suggest a 60-day, or March 1, allowance transfer deadline. They claim that such a deadline is in the interest of a viable and flexible emission trading system, and that it provides adequate time for the staffs of small utilities to comply with the complex rules.

Response: As stated in the preamble to the proposed rule, EPA believes the additional flexibility of an extended allowance transfer period is important to the Acid Rain program and is also consistent with Congressional intent.

The final rule, in § 73.35(a), sets January 30 as the date of the allowance transfer deadline. EPA continues to believe that a January 30 deadline provides units with ample time to transact and submit allowance transfers, and in the case of units with excess emissions, to submit offset plans within 60 days after the end of the year.

Through continuous emissions monitoring under part 75, units will be able to estimate their emissions during the year and determine their exact annual emissions within hours of year-end. This capability will allow allowance or power pools as well as individual units plenty of time to transact and transfer allowances before January 30.

A February 14 allowance transfer deadline would compress the amount of time for both EPA and the authorized account representatives to complete several time-consuming activities which must occur before March 1. First, EPA will have to record transfers and notify the authorized account representatives as to whether the trades are recorded. If a large volume of transfers are submitted at once, there may be a delay between submission and recordation for any given transfer. Second, the authorized account representatives will need to determine the accuracy of any recordations and, if necessary, to submit error claims to EPA. Finally, EPA will have to resolve each error claim. EPA believes that the period from February 15 to March 1 does not offer sufficient time to carry out these activities reliably, especially in Phase II of the Acid Rain program when the number of affected units will increase to over 2,000.

Extending the allowance transfer deadline to March 1, as several commenters suggested, would leave no time for these activities and is therefore not a viable option.

Because of all the activities that must take place between the January 30 allowance transfer deadline and the March 1 deadline for submission of excess emissions penalties and offset plans, EPA strongly encourages utilities to submit allowance transfers before the January 30 deadline. Designated representatives should try to submit compliance-related transfers prior to the allowance transfer deadline because if an error is made on the transfer form, there would still be time to resubmit the transfer before the January 30 deadline. Under the final rule, resubmission of the transfer after January 30 would be too late to use these allowances for compliance purposes in the previous calendar year. An additional incentive to submit transfers early is that it provides more time to file a claim of error regarding an allowance transfer and to have the claim resolved (see next section). Resolution of a claim of error could be of critical importance if the trade's outcome determined whether the unit was in compliance.

B. Serialization

In § 73.34(d) EPA proposed to assign a unique identification number to each allowance. Most commenters supported EPA's proposal because it provides a method for establishing a cost basis for allowances and, therefore, greater flexibility for tax and compliance planning purposes. A few commenters, however, disagreed with the need for serialization, except to indicate the compliance use date for each allowance. One commenter argued that the compliance use date was necessary to establish the cost basis for an allowance, but that the assignment of a unique number would destroy the fungibility of allowances. Another said that EPA's assignment of a unique number was unnecessary because a utility would probably assign its own unique numbers that are consistent with its internal accounting system. A third commenter argued that the administrative burden of assigning a unique identification number to each allowance outweighed any possible benefits. Still another commenter claimed that only an identifier of the year for which the allowances are valid and the attachment of a transaction number when allowances are transferred are necessary for tracking purposes.

One commenter recommended that, in addition to the compliance use date, an allowance's unique identification number include a means of identifying the source of the allowance's original allocation. This would enable utilities and their regulators to distinguish between allocated and acquired allowances for tax and accounting purposes.

Response: EPA continues to believe that the assignment of unique serial numbers to allowances will provide significant flexibility to the market's participants in their financial, tax, and compliance planning efforts. Furthermore, because such numbers would be useful to most companies for their internal recordkeeping purposes, EPA decided that the aggregate benefit of providing a standard numbering system outweighs the administrative cost to EPA of generating and tracking the identification numbers.

In response to the comments, EPA will assign a unique number to each allowance that will include the compliance use date and that will enable utilities to differentiate between allocated and purchased allowances. EPA is including the compliance use date as part of the unique number to further enhance the establishment of a cost basis for each allowance. EPA agrees that it will be useful to readily identify compliance dates and to distinguish allocated from acquired allowances using serial numbers since it is important to utilities and regulators for establishing a cost basis for allowances.

EPA is not providing, by regulation, the exact format of the serial numbers for the allowance system. In implementing the system, EPA will

limit the use of source codes to those cases where such identification is necessary.

C. Verification of Energy Savings

Section 404(f)(2)(B)(ii) of the Act requires an applicant to the Conservation and Renewable Energy Reserve (CRER) to quantify its estimates of avoided emissions according to regulations promulgated by the Administrator. EPA proposed to defer conservation verification to State regulators in cases where the State has regulatory oversight. EPA's rationale for this approach was that regulatory scrutiny for conservation savings applied for under the Reserve is likely to be fairly rigorous because utilities applying for the program must be subject under the Act to "net income neutrality" ratemaking structures. EPA also reasoned that with the complexity and multitude of verification methods for energy savings, verification guidelines must be flexible enough to allow States to develop procedures that best suit the circumstances of their utilities. In cases of non-State-regulated utilities, EPA proposed to require the use of an EPA Conservation Verification Protocol (CVP), to be published at a later date.

Some commenters questioned EPA's approach for deferring verification of energy savings to States. It was noted that some methods of net income neutrality rate-making do not link the revenues awarded to the utility with the amount of verified energy savings. For example, ratemaking structures that decouple a utility's revenues from sales volumes do not require verification of savings from conservation programs. Several commenters also noted that State verification methods vary widely in their accuracy and rigor. For example, some States base their verification of savings solely on engineering estimates, which may be grossly inaccurate.

Commenters gave a number of suggestions for revising the criteria for deferring conservation verification to States, including (1) requiring all applicants to the Reserve to use the CVP or some other verification standards that EPA would promulgate, which might include region-specific engineering estimates for conservation measures; (2) having EPA adopt State estimates of energy savings only in cases in which the State requires "measured" energy savings, i.e., savings that are verified in statistically valid studies using billing data or data collected by electricity end-use sub-meters; and (3) having EPA defer to States only if the State uses evaluation of energy savings to determine performance-based financial awards for energy conservation programs and these performance based awards are subject to adjustment to reflect periodic evaluation of energy savings.

Response: EPA has decided to adopt this last approach with one modification. Section 73.82(c) of today's rule allows States to perform verification of energy savings if they use evaluation of energy savings to determine *any* type of performance based rate adjustment, rather than just performance based *financial awards*, as suggested by the commenter. EPA believes that allowing this broader category of performance based mechanisms is more consistent with today's definition of net income neutrality, which allows both performance-based financial awards (i.e., "shared savings mechanisms") and "lost revenue adjustment mechanisms." For both of these types of mechanisms, regulators must evaluate energy savings achieved by utility conservation programs in order to determine the proper adjustment to a utility's rates necessary to recover lost revenues or to provide a financial award.

EPA has adopted this approach for several reasons. First, the Agency believes it is representative of EPA's original rationale of deferring to State regulators where verification is likely to be fairly rigorous. The Agency believes that there is an incentive for rigorous verification when evaluation of energy savings is used to determine how much of the ratepayer's money will go towards conservation incentives. In contrast, without this tie to performance based rate adjustments, States might have an incentive to overestimate savings to obtain the largest number of Reserve allowances.

Second, although the use of engineering estimates would still be allowed, the requirement to periodically modify performance-based rate adjustments through the evaluation of energy savings would help ensure that the State is committed to good evaluation practices. EPA notes that evaluation of energy savings is a new and rapidly evolving field and that States often begin their evaluation programs solely with engineering estimates. Most evaluation experts agree, however, that while engineering estimates are useful, they should be supplemented with a statistically valid measurement of the change in energy use resulting from installation of conservation measures.

Finally, EPA believes that this approach is more consistent with the fundamental approach of the Acid Rain program, which encourages flexibility but insists upon appropriate measurement standards. Thus, while today's regulations provide a minimum standard for deferring conservation verification to States, EPA is not prescribing verification methods or procedures. States will still have the flexibility to design their own verification approaches. Because of the diversity of evaluation methodologies and the ongoing evaluation activities of States, EPA believes that this approach will be more effective than mandating specific methods or requiring universal use of the CVP.

EPA also notes that it has modified the proposed verification requirement for applicants that do not qualify to have verification performed by their State commissions. The proposal required such applicants to use the CVP. The final rule requires applicants to demonstrate to the satisfaction of the Administrator that energy savings have been secured and allows applicants to do so through use of the CVP.

D. Appropriate Biomass Categories

EPA proposed to allow the biomass component of municipal solid waste (MSW) to be considered as biomass resources for purposes of the Reserve. The Agency noted in the proposal that inclusion of MSW was consistent with the definition of biomass in the Public Utility Regulatory Policies Act of 1978 (PURPA). EPA also proposed to limit the total number of allowances that may be allocated in connection with any one of the four categories of renewable resources—biomass, solar, geothermal, and wind—to no more than 10% of the Reserve, or 30,000 allowances. This reflected EPA's concern that biomass, which, in the aggregate, represents more than 90% of the combustible MSW stream, could absorb a disproportionate share of the Reserve.

Twenty-five commenters opposed EPA's proposal to allow the biomass components of MSW to be considered a biomass resource for purposes of the Reserve. One set of commenters stated that the goals of PURPA and the Clean Air Act are entirely different; PURPA was intended to stimulate energy production, while the Clean Air Act was designed to promote clean air. Moreover, these commenters argued the CRER was created to accelerate the development of conservation measures and renewable energy technologies that meet two standards: (1) They enhance the goals of the Act to improve air quality, and (2) they are in greatest need of an additional Federal incentive. The commenters argued that while incineration of MSW may be a suitable

method of solid waste disposal in some cases, it does not meet these two standards.

Fifteen additional commenters noted that MSW waste-to-energy projects are not environmentally benign or beneficial, and they emit a number of pollutants including SO_2, NO_x, particulates, and a variety of toxics. Commenters also contended that MSW waste-to-energy generation is a well developed technology that does not need additional incentives. Finally, several commenters argued that the additional incentive for incineration of MSW provided by Reserve allowances could disadvantage more environmentally beneficial solid waste disposal options such as source reduction and recycling.

Only one commenter unequivocally supported EPA's proposal to allow the biomass components of MSW to be considered a biomass resource for purposes of the Reserve. The commenter argued that all renewable technologies covered by PURPA should be considered qualified renewable energy technologies for purposes of the CRER.

One additional commenter argued that before receiving allowances from the CRER, waste-to-energy projects should obtain certification from the Department of Energy (DOE) that the project was operating in full compliance with an approved integrated solid waste management plan. The commenter stated that this plan should include recycling to the maximum extent practicable.

Response: EPA, having considered these comments, finds that there is no policy or statutory basis for excluding the biomass component of MSW as a biomass resource for purposes of the Reserve. While commenters are correct in noting that MSW waste-to-energy (WTE) projects emit a number of pollutants, EPA has already promulgated regulatory standards that mandate, reductions in these emissions to acceptable levels (*FR* Vol. 56, No. 28, February 11, 1991, p. 5488). Moreover, WTE plants often yield certain environmental benefits in addressing solid waste management concerns. In any event, the Act does not contemplate an environmental ranking of renewable energy technologies.

EPA agrees with the comment that WTE technology is both mature and geographically dispersed. The number of WTE projects has grown substantially in recent years—65 WTE projects began operation in the years between 1980 and 1989, and 75 additional projects are planned or have recently begun operations. However, the exclusion of a particular renewable technology from access to the Reserve merely because it is highly cost-effective would be totally inconsistent with the thrust of the emissions allowances system, which uses a flexible market-based system rather than a command-and-control approach precisely because the former can elicit the most cost-effective responses to meet environmental objectives and energy needs. Finally, Congress explicitly considered the definition of "qualified renewable energy" in the Act and, while explicitly excluding hydropower, did not exclude WTE biomass. Thus, on legal as well as policy grounds, it would be inappropriate for the Agency to impose such a restriction. Accordingly, after considering the comments received, the Agency has determined that MSW will remain on the list of qualified renewable energy technologies in Appendix (A)(3) of today's rule.

The proposed rule assured that no single technology would absorb a disproportionate share of the Reserve by limiting to 30,000 the amount of allowances that can be allocated from the Reserve. This same limitation is included in the final rule.

E. Other Changes to Part 73

(1) Allowance Accounts

In § 73.31(a) of the proposed rule, EPA specified that the allowance account for an existing affected unit would be established in the Allowance Tracking System no later than January 30, 1993. Accounts for new units would be established upon receipt of a valid certification of representation for a new unit pursuant to part 72.

Upon review, EPA is eliminating the specification that EPA establish Allowance Tracking System accounts by no later than January 30, 1993. Because EPA imposed this specification upon itself and it was not a statutory requirement, EPA believes its inclusion is unnecessary.

(2) Freezing of Accounts

In § 73.50(a)(4) EPA proposed to prohibit, or give the Administrator the discretion to prohibit, EPA from executing any transfers of allowances from a compliance subaccount if the unit had excess emissions in the previous calendar year and the Administrator had not yet deducted allowances or approved the unit's offset plan. In such cases, EPA would have allowed a transfer if the number of allowances in the compliance subaccount equaled or exceeded the sum of the number of allowances subject to the transfer and the unit's excess emissions in the previous year.

Several commenters questioned the purpose of giving EPA authority to "freeze" an affected unit's subaccounts in the ATS under these conditions. Specifically, they requested EPA to delete these proposed provisions (§ 73.50(a) and § 73.55(b)).

Response: On reexamining this issue, EPA has decided to delete these provisions and has revised the rule accordingly. EPA reasons that even if a unit's offset plan to cover its excess emissions in the previous year has not yet been approved and allowances have not yet been deducted for excess emissions, EPA should allow transfers of allowances out of the current year's compliance account. Once the offset plan is approved, EPA could deduct allowances from the current compliance subaccount as the plan requests. If a unit fails to abide by its offset requirements and lacks sufficient allowances in its current compliance subaccount to cover its excess emissions, EPA has the authority in accordance with § 77.4 to automatically deduct allowances from the current compliance subaccount whenever more allowances are recorded in the compliance subaccount. The only situation in which allowances would be unavailable to EPA would be if the unit transferred all allowances from its account and ceased operation, which could be done before an offset plan is even submitted to EPA. In such a case, EPA could pursue enforcement actions. Therefore, EPA agrees that the proposed provisions concerning freezing an affected unit's subaccount are duplicative and unnecessary.

The final rule contains language under the general requirements of part 72, subpart A that allows EPA to take action to protect the orderly and competitive functioning of the allowance system. This is to ensure that EPA is able to protect the allowance system and participants from fraud or misrepresentation.

(3) Account Error and Dispute Resolution

As proposed in § 73.37, EPA required that all claims of error be submitted within 20 business days following the date of submission of the recordation notice or within 10 business days of the date of EPA's notification of the recordation. Only one additional appeal to the Administrator's decision of the submitted claim would be considered. No appeals provision was made for EPA's corrections and the Administrator's discretion to waive deadlines.

Commenters requested that such appeals procedures be extended to

apply also to corrections made at EPA's own discretion and the Administrator's right to waive deadlines. Other commenters supported having a more formal administrative appeals procedure, similar to the one proposed in part 72, to cover any action by the Administrator under part 73.

Response: EPA reviewed its proposed claim of error procedures to ensure that adequate response time for account holders is provided consistently throughout the compliance period. EPA is modifying the claim of error process so that only properly documented claims submitted within 15 business days following the date mark of notification of the transfer's recordation will be considered, subject to the waiver of deadlines process § 73.37.

As defined in § 73.37, a properly submitted claim consists of (1) a description and complete documentation of an error allegedly made by EPA, (2) a proposed correction, and (3) certification by the authorized account representative. Any appeal of the decision made by the Administrator in response to the submitted claim of error will be handled through the administrative appeals procedure contained in part 78. The deadline and process will not be altered for claims submitted near or after the Allowance Transfer Deadline. This means that unless EPA uses its discretion to waive the deadlines, EPA would have 20 business days to respond in writing to a claim of error received on the allowance transfer deadline. Thus, the designated representative might not know the outcome of the claim until after March 1. This could present a problem to the designated representative where the outcome of this claim of error is of critical importance in determining whether the unit was in compliance. However, if EPA made an error in recordation that appeared to put the unit out of compliance, EPA will correct the error and acknowledge that the unit was in compliance.

Based on supporting comments received, EPA is extending the claim of error process to cover EPA corrections, and the administrative appeals process described in part 78 will extend to appeals of the Administrator's discretion to waive deadlines contained in § 73.37(f).

In addition to the claim of error process for allowance transfers, the administrative appeals procedure in part 78 can be applied to any decision or action by the Administrator under part 73.

(4) Authorized Account Representative Notification of Submissions

In part 72, EPA proposed that the designated representative provide each owner and operator with a copy of any Acid Rain program submission. EPA did not propose in part 73 that the authorized account representative notify all persons who have an ownership interest in the account of any Acid Rain Program submissions. This meant that non-unit account holders may be unaware of submissions made by their authorized account representative.

One commenter suggested that where the designated representative is engaging in a transfer that violates the binding agreement to represent the owners, EPA should temporarily halt the transfer for a period of time sufficient to obtain a temporary injunction pending resolution of the conflict.

Response: Under part 72 the designated representative is required to notify all owners and operators of any Acid Rain program submissions. In addition, § 73.33(b) of the final rule requires the authorized account representative to notify all persons who have an ownership interest with respect to the allowances held in the account of any part 73 or part 78 Acid Rain Program submissions by the date of the submission.

EPA is requiring such notification for all account holders for two reasons. First, where a transfer violates the binding agreement, requiring the notification will give an owner or a person with an ownership interest at least the period of time that it takes EPA to process and record the transfer to obtain a temporary injunction from a court. Second, because in some cases utilities will set up non-unit accounts to pool allowances, EPA believes this notification requirement is necessary to ensure that the owners and operators of the units in the allowance pool are notified. EPA is limiting this notification requirement to part 73 and part 78 submissions because the other parts are not relevant to non-unit accounts.

(5) Allowance Deductions for Units Sharing a Common Stack

In § 73.35(f) of the proposed rule, EPA planned to aggregate the allowances in the compliance subaccounts for all units governed by a common stack plan for purposes of deducting allowances to meet SO_2 emissions limitation requirements. Following the deductions, EPA would return any remaining aggregated allowances to each unit's account on a per capita basis.

EPA received one comment supporting the proposal. However, the commenter noted that the importance of this aggregation will be less if EPA proceeds with its non-unit account proposal.

Response: EPA reviewed and decided to modify the manner in which allowances are deducted for units sharing a common stack. Instead of aggregating allowances, § 73.35(e) of the final rule allows the designated representative to identify the percentage of allowances to be deducted from each unit's compliance subaccount. In the absence of such an identification, EPA will deduct an equal percentage from each unit's compliance subaccount. Of course, the designated representative still has the option to identify, by serial number, the specific allowances to be deducted. These specific allowances would be deducted first; then, if more allowances need to be deducted, the percentage would be applied.

EPA is making this change to conform to the unit-by-unit allocation and compliance provisions of the Act and the Acid Rain program. By aggregating the allowances as in the proposal, if one unit is in violation for excess emissions, then all are. However, this rule enables compliance and excess emissions violations to be determined on a unit-by-unit basis by applying a percentage for allowances to be deducted from each unit's compliance subaccount. Also, since EPA is proceeding with the non-unit account proposal, EPA agrees with the commenter that aggregating allowances is less important.

(6) Transfer Recordation—Non-recordation of Transfers

Four commenters requested EPA consider the date of recordation of a transfer to be the date it was originally received by EPA. They also requested that any subsequent claim procedures to correct the recordation of a transfer not affect the original date of recordation, which would be the original date of its receipt by EPA.

Response: Although EPA understands the commenters' concern that the original date of submission be acknowledged, EPA does not believe the date of recordation will have substantial impact on the effectiveness of any transfer agreements. The buyer and seller can arrange the date their agreement takes effect for legal purposes separately from the actual date of transfer of allowances by EPA. Therefore, EPA has not changed the rule, and the date of recordation will be the date EPA enters the information into the Allowance Tracking System. Any incomplete or inaccurate transfer forms

will be returned to the senders and will not be recorded. Resubmitted transfers will be treated as if they are a new transfer and the date of recordation will be the date EPA enters the information into the ATS. The original date of submission is not considered to be the date of recordation because resubmitted transfers are considered to be new transfers.

(7) Collection of Market Information

EPA proposed not to collect price and other terms of allowance transactions, and the rule is not changed from the proposal, despite some comments expressing concern on this issue.

Response: While EPA is not collecting information on price and other terms of allowance transfers, EPA is providing some market information by publishing the results of the annual auction and sale and by making the information contained in each allowance account available, in summary form, for public review. EPA recognizes that there are concerns about the availability of market information on allowances. EPA continues to believe that market information on allowances will be available through other public and private channels such as the Federal Energy Regulatory Commission (FERC) and futures exchanges. However, to address these concerns EPA will evaluate the allowance market and the availability of market information prior to Phase II to determine what action, if any, may be needed.

(8) Least Cost Planning

(a) Section 404(f)(2)(B)(iii)(II) of the Act requires qualified energy conservation measures or qualified renewable energy generation to be consistent with the applicant's least cost plan. Although this requirement was included in § 73.82(a)(5) of the proposal, it was inadvertently omitted from § 73.81(c)(2) of the proposal, which listed the requirements for approval of qualified renewable energy technologies not already listed in Appendix (B)(1) of the rule. Section 73.81(c)(2)(i) of today's rule has been corrected to include this requirement.

(b) One commenter questioned the relevance of the proposed rule's least cost planning requirement for independent power producers (IPPs) that make use of renewable energy. Generally, these units sell wholesale power to other utilities and are not subject to least cost planning requirements. The commenter suggested that it would be more meaningful to require these types of applicants to demonstrate that the renewable energy generation was *purchased* pursuant to the *purchasing* utility's least cost plan, which should be approved or accepted by the appropriate regulatory authority.

Response: EPA agrees with the commenter and has adopted the suggested change in § 73.82(a)(8). The Agency believes that this approach is more consistent with the actual operation of IPPs and with the intent of the Act.

(c) EPA proposed that if an applicant to the Reserve is not subject to the ratemaking jurisdiction of a State regulatory authority, its least cost plan must be approved and certified by the entity with rate-making authority for the applicant. The Agency also proposed that applicants not subject to the rate-making jurisdiction of an entity with ratemaking authority must apply to the Administrator for approval of the plan. Five commenters suggested that the rule language be clarified to specify that public power utilities not subject to State ratemaking authority have their plans approved by the appropriate local ratemaking authorities. In addition, several commenters noted that *all* utilities are subject to the rate-making jurisdiction of an entity with rate-making authority. These commenters suggested that EPA clarify that a least cost plan could be approved by any entity with rate-making authority.

Response: EPA agrees with the commenters' suggestion and has revised language in § 73.82(a)(6) and § 73.82(a)(7) of the final regulations to clarify that the least cost plan may be approved by any entity that regulates the rates of the applicant.

(d) EPA also received comments urging the Agency to revise the proposed rule so that the definition of an "approved" least cost energy plan includes least cost plans that are "accepted" by the State regulatory authority. The commenters suggest the change because some State regulatory authorities are unwilling to approve a utility's least cost plan out of concern that such approval will tie the hands of future State regulatory bodies. However, these State authorities will *accept* a least cost plan if it complies with the State regulatory authority's requirements.

One commenter also suggested that where States implement ratemaking and planning processes that are consistent with least cost planning principles, they should not need to have a formal "plan."

Response: The final rule contains two changes regarding the requirements for regulatory oversight of a utility's least cost plan. The first, in § 73.82(a)(6) and § 73.82(a)(7), would allow a commission to "accept" a least cost plan in addition to "approving" a least cost plan. The second change, in § 73.82(a)(4), would allow a utility to meet the least cost planning requirement if it has a least cost plan *or* a "least cost planning process."

(e) One commenter questioned EPA's requirement that least cost plans be subject to public notice and comment. The commenter stated that EPA should allow States to use alternative public participation procedures such as collaborative processes that allow public participation from interested groups.

Response: Section 73.82(a)(4) of the rule has been revised to require public notice and comment on a least cost plan *or* a comparable public participation process.

(9) Net Income Neutrality

EPA received comments on several issues related to the net income neutrality provision. The Agency has addressed these comments in consultation with the Department of Energy (DOE), which is responsible for certifying that an applicant's State regulatory authority has implemented provisions that meet net income neutrality requirements.

(a) Six commenters stated that the definition of and the requirements for net income neutrality should state explicitly that they only apply to investor-owned utilities (IOU). The commenters noted that public power utilities are non-profit and do not have "net income."

Response: EPA and DOE agree with the commenters and have added language to § 73.82(a)(9) of today's regulations that specifies that this requirement only applies to IOUs.

(b) One commenter argued that the three compliance approaches for net income neutrality specified in § 73.82(a)(9) do not, in and of themselves, constitute net income neutrality.

Response: EPA and DOE believe that the mere existence of one of these three mechanisms does not necessarily meet the net income neutrality requirement and that the specifics of each rate-making mechanism must be reviewed by the Secretary of Energy before a determination of net income neutrality can be made. Accordingly, § 73.82(a)(9)(ii) of today's regulations clarify this point.

(c) Three commenters stated that the proposal's definition of net income neutrality implies that utilities must use a "rate basing" accounting mechanism for recovering the costs of conservation programs. The commenters contend that the term "net income on book value"

used in the definition suggests that conservation expenditures must be treated as a capital expense that should be included in the utility's ratebase. These commenters noted that many utilities use an "expensing" mechanism to recover conservation expenditures, a mechanism that does not add to utility book value.

Response: It was not the intent of the proposal to prescribe the type of cost recovery mechanisms that may be used for conservation expenditures. EPA and DOE believe that the choice of cost recovery mechanisms should be left to the discretion of utilities and their economic regulators. Therefore, the term "book value" has been deleted from the definition of net income neutrality in § 72.2 of today's regulations.

(d) Five commenters argued that the definition of net income neutrality should not imply that ratemaking procedures should *guarantee* that utility incomes will be no lower if investments in conservation are made. Rather, ratemaking procedures should provide the *opportunity* for utilities to earn a net income comparable to that which it would have achieved without the conservation programs. The commenters noted that under some shared savings incentive mechanisms the return received by some utilities depends upon the verified performance of their conservation investments.

Response: EPA and DOE agree that providing an opportunity for net income neutrality is consistent with the intent of the net income neutrality requirement. These regulations modify the definition of net income neutrality in § 72.2 to include State ratemaking approaches that provide for this opportunity based on performance-based results of conservation programs.

(10) Qualified Conservation Measures

(a) Three commenters stated that EPA should clarify or delete the requirement that there be no net increase in sulfur dioxide from qualified conservation measures. For example, one commenter noted the difficulty of determining the exact type and amount of fuel that might be avoided by the marginal energy savings of a particular conservation measure.

Response: EPA notes that it was not the intent of the proposed regulations to require such a detailed evaluation of the emissions impacts of given conservation measures. Rather, the requirement was directed towards measures that increase energy efficiency by utilizing industrial waste gases containing sulfur. EPA believes that where utilization of these waste gases does not lead to a net increase in sulfur dioxide (i.e., cases where the gas is already being flared), these measures should be considered qualified energy conservation measures. The Agency has modified language in § 73.81(a) and § 73.81(b) of the regulations to better reflect the intent of this provision.

(b) EPA received a comment that supported EPA's criteria for approving qualifying DSM measures not explicitly listed in the appendix to the regulations. However, the commenter explained that requiring specific approval of qualified conservation measures by the applicable State regulatory authority or by the Administrator may stifle flexibility to install innovative measures.

Response: The final rule, therefore, states in § 73.81(a)(2) that EPA will deem as qualified each conservation measure installed pursuant to a conservation *program* and approved by the relevant authority, as long as it meets the criteria listed in § 73.81(a) and is not an excluded measure under § 73.81(b).

(11) Applicability for CRER

(a) EPA proposed that an applicant would be eligible to apply to the Reserve if "any subsidiary of the applicant" owns or operates an affected unit. One commenter argued that eligibility should also extend to any subsidiary of the applicant's *holding company* that owns or operates an affected unit, either in whole or in part.

Response: EPA agrees that this change reflects the language and intent of the Act, and § 73.82(a)(2) of today's regulations reflect this change.

(b) EPA also proposed that an applicant would be eligible to apply for the CRER if it is a utility or an industrial customer that purchases power from an affected unit under a "life-of-the-unit" firm power contract.

Response: The Agency now believes, however, that it would be contrary to the intent of the Act to allow industrial customers that purchase power from affected units to qualify for the Reserve. Section 404(f)(2)(A) clearly requires that an applicant to the Reserve be an "electric utility", which is defined in section 404(f)(1)(C) as any person, State agency, or Federal agency, which sells electric energy. Since industrial customers with a life-of-the-unit contract *buy* electricity, rather than *sell* electricity, they would generally not meet the definition of an electric utility. Consequently, § 73.82(a)(2) of these regulations deletes industrial customers from the language describing the types of eligible applicants to the Reserve.

(12) Application Requirements

(a) EPA proposed that applicants to the Reserve must pay in whole or in part for qualified conservation measures or qualified renewable energy generation, either directly or through payment to another person. The Agency also proposed that the applicant must specify the amount spent on the conservation measure or renewable energy generation. One commenter argued that in the case of renewable energy generation produced by independent power producers, these expenditures are proprietary information that should not be disclosed.

Response: EPA now believes that information on expenditures of both renewable energy generation and qualified conservation measures are unnecessary. Rather, EPA will require in § 73.82(a)(3) that applicants to the Reserve certify that they have paid for the qualified conservation measures or qualified renewable energy generation.

(b) EPA proposed to allocate allowances from the Reserve for qualified renewable energy generation purchased or generated by an applicant. One commenter stated that EPA should allocate allowances for qualified renewable energy generation only to utilities purchasing such generation, rather than to the generating utilities. The commenter argued that such a policy would provide the strongest incentive for the development of renewable energy.

Response: EPA believes that the commenter's suggestion would be contrary to section 404(f)(2)(F) of the Act, which clearly provides for allocation of Reserve allowances to *both* purchasers and generators of qualified renewable energy generation. However, EPA has added language to § 73.84(g) of these regulations that would prevent the generator and the purchaser of the same renewable energy generation from receiving allowances from the Reserve based on the same kilowatthours of electricity generation and the same avoided emissions. These regulations provide that these applications would be processed and approved in order of the date of receipt. If applications based on the same renewable electric generation are received on the same date, allowances awarded will be divided evenly between all the relevant applicants unless the Administrator is otherwise directed by all applicants. EPA strongly encourages qualified generators and purchasers of the same electricity generated by qualified renewable energy technologies to coordinate their applications to the

Reserve to avoid confusion over allowance awards.

(c) EPA proposed that applications to the CRER be submitted to the Administrator beginning on January 1, 1993. Eleven commenters suggested that EPA delay this date to allow time for more accurate verification of conservation savings. Commenters had a variety of suggestions for how long to delay the application date, ranging from three to twenty months. Three commenters supported the January 1 date or suggested minor modifications.

A number of commenters argued that since the allowances from the Reserve are allocated on a first-come-first-served basis, there will be pressure to send in applications to the Administrator before complete and accurate verification of conservation savings can be fully assured. Commenters noted that verification of conservation savings is time consuming, particularly verification of savings resulting from complex conservation programs. The commenters also noted that a January 1 application date leaves too little time for verification of savings by State regulatory authorities.

Several commenters argued that an early application deadline penalizes utilities that use more rigorous (and time consuming) verification methods such as metering, bill analysis, and statistical models. Utilities that use simpler and potentially less accurate engineering estimates would be able to apply for allowances sooner. Several commenters also noted that an earlier application date would give an unfair advantage to publicly owned utilities, which are not required to go through state review and verification processes before submitting their applications to EPA.

Response: EPA believes that delaying the application date will encourage good verification of energy savings. The Agency recognizes that evaluation of energy savings requires time for data collection and analysis. Although States are not required to file their applications on the application date, there would be an advantage to filing earlier because allowances are awarded from the Reserve on a first-come-first-served basis. Moreover, because EPA is not mandating a single verification methodology, there could be an unfair advantage for utilities in States that allow verification methodologies that take less time to implement.

The Agency believes that a delay of the application date by six months would provide a reasonable amount of time for States and utilities to complete verification of energy savings. Therefore, § 73.82(g) of these regulations allow utilities to submit applications beginning July 1, 1993, and on July 1 of each subsequent year for the savings achieved in the previous year. (For example, an applicant could apply for savings achieved in 1993 on July 1, 1994.)

Because these rules delay the annual application date by six months to allow more time for verification of savings, EPA believes it is now more likely that the Reserve will become oversubscribed by more than one applicant on a single day than was anticipated under the proposal. (EPA does not anticipate that an oversubscription will occur during the first several years of applications.) A January 1 application date would have led to a more gradual stream of applications over the first part of the year as utilities and their State commissions completed verification of the previous year's energy savings at different times.

Accordingly, § 73.84(f)(1) of the final rule provides that in the event that the Reserve becomes oversubscribed by more than one applicant on a single day, the allowances remaining in the Reserve will be distributed on a pro rata basis. EPA believes that this method for allocating allowances is administratively simple and is appropriate for the Reserve. EPA also considered other methods, such as a lottery, for allocating allowances from the Reserve when it is oversubscribed. However, unlike the Phase I extension provision where 100 percent of the incentive allowances are expected to be claimed on the first day of application, EPA expects that a relatively small portion of the Reserve allowances will remain when it becomes oversubscribed. Thus, because of the relatively few allowances at stake, EPA does not believe that the extra administrative burden of a public lottery would be merited.

F. Return of Auction and Direct Sale Proceeds Under Subpart E

Under subpart E, which was previously published as 40 CFR part 73, in 56 FR 65592–65607, December 17, 1991, EPA must return the proceeds from the auction and direct sale within 90-days of the conclusion of the auction or sale. EPA is planning to return the proceeds by sending a proceeds check to the designated representative for each unit. Until the unit has filed a certificate of representation for the designated representative under subpart B of part 72, EPA will not know the person to whom the proceeds check must be sent. Therefore, EPA will hold the proceeds check until a certificate of representation is filed with EPA. Because EPA will be selling allowances in the advance auction that are taken from Phase II units, and because EPA cannot pay any interest on the proceeds, Phase II units are encouraged to submit a certification of representation for the designated representative before the first auction in March 1993.

V. Discussion of Changes to Part 75—Continuous Emissions Monitoring

This part of this final rule explains the major changes made to part 75, the proposed Continuous Emissions Monitoring (CEM) rule, in response to public comment.

Some structural changes are incorporated into the final CEM rule. First, many of the general provisions contained in subpart A of the proposed CEM rule, such as definitions and abbreviations, have been consolidated for the Acid Rain Program in subpart A of part 72. Second, the proposed rule had only two subparts (A—General and B—Standards); the final rule recognizes that many of the provisions can be grouped functionally into several subparts: subpart B—Monitoring Provisions, incorporates §§ 75.11–75.16 from the proposed rule; subpart C—Operation and Maintenance Requirements, incorporates §§ 75.18–75.20, as well as the procedures for proposing alternatives to the ASTM methods that were originally contained in § 75.21 in the proposed rule; subpart D—Missing Data Substitution Provisions, consolidates the missing data procedures that were located throughout the monitoring provisions, §§ 75.12–75.16 in the proposed rule; subpart E—Alternative Monitoring Systems, incorporates the provisions originally contained in § 75.21 in the proposal; subpart F—Recordkeeping Requirements, incorporates the provisions originally contained in § 75.22; and subpart G—Reporting Requirements, contains the provisions in § 75.23.

While the Appendices have not been reformatted, two new appendices have been added: A new Appendix E (Optional NO_x Emissions Estimation Protocol for Gas- and Oil-Fired Peaking Units), as well as Appendix G (Optional determination of CO_2 Emissions). These appendices were created for this final rule, in response to comments. As a result, the old Appendix E from the proposed rule (Conversion Procedures) has been moved in the final rule to Appendix F.

In the final rule the term "designated representative" now often appears in places where the term "owner or operator" appeared in the proposed rule. As the official responsible for

meeting the reporting requirements under the Acid Rain Program, the designated representative represents the owner and operator when reporting is required. The term "owner or operator" is used in the final rule when action is specifically required at the source.

Overall, the proposed CEM rule received more than 2,700 comments, or approximately 35 percent of the total number of comments received on the proposed core rulemaking package. Approximately 70 percent of the comments received on the proposed CEM rule fell into eight major issue categories: certification and recertification, relative accuracy and Relative Accuracy Test Audits, bias test and bias adjustment factor, flow monitoring, alternative monitoring systems, missing data procedure, exceptions to monitoring with CEMS, and Quality Assurance/Quality Control issues (including calibration testing). Responses to public comment on these major CEM rule issues are discussed below.

A. Certification and Recertification Issues

There were numerous comments related to the certification and recertification of CEM systems. The comments fell into roughly two broad comment categories: notification and Administrator response requirements, and recertification. The EPA's intent is to foster a cooperative environment where the sources seek to initiate, and work through, the process of certification as soon as possible with the appropriate certifying Authorities. The EPA believes that this cooperative effort involving frequent and open communication between sources seeking certification and the certifying authorities will facilitate the start up of the program.

(1) Notification Requirements and Administrator Response

Issues: A number of commenters indicated that the time needed for the Administrator to respond to a certification request coupled with a 30 day notification-of-testing requirement along with, at a minimum, a 7 day certification test would force sources to initiate a CEM certification almost 6 months in advance of the deadline by which the Act states a CEM must be certified. Commenters also indicated that it was unclear as to the procedures a source could follow if, during the course of a certification test, a unit was determined to be failing that test or what to do in the event certification test dates need to be adjusted after notifying the appropriate authorities. Furthermore, commenters had concerns with the requirements placed on new units that would be coming online in the future.

Response: EPA has clarified in the accompanying rule when a new unit would need to be certified. This requirement is based upon an analysis of the intent of the Act to account for all emissions from affected sources in a two phased approach and with the recognition that not all affected sources will be operating prior to January 1, 1995. Furthermore, this rule takes into account the comment that some types of units that will be affected can be brought online and turned over to the dispatcher in a relatively short period of time and that units typically need to burn some fuel prior to a time when a CEM system can be in and certified.

EPA analyzed the reporting, notification, and approval procedures, time frames, and burdens on the sources and governmental resources in response to the comments received. EPA has modified the certification forms and process to include more interaction between sources and agencies, however the overall time that this rule is reserving for notification of testing and review of completed certification submittals has been *reduced* relative to the statutorily mandated deadlines for units to have certified CEM systems operational. EPA analysis indicates that the new procedures and forms will require 45 days to properly review at a minimum and should, therefore, be submitted at least that far in advance of the commencement of certification testing. However, EPA believes that (and actively encourages) the cooperative procedures developed will actually be initiated far in advance of 45 days and proceed in a series of logically derived steps that will culminate in a fully successful certification.

This cooperative, multi-step process also leads the agency to believe that monitors can be provisionally certified upon the successful completion of certification testing and that if a unit is determined to be failing a certification test that a new series of tests can be commenced immediately as part of the certification effort. The Administrator will still need to reserve the full 120 days from receipt of a complete certification request to perform analysis of test results before a final notice of certification can be served to a particular CEM system; however, all data collected from a provisionally certified system that is subsequently fully certified is valid data and provisional certification meets the requirements of the Act with respect to the dates by which units must install and operate CEMS, quality assure the data and keep records and reports.

For this reason, EPA has determined that the certification testing must be completed and the system(s) must have initiated full, quality assured operation by the statutory deadlines. However, the unit may submit its certification request complete with the required test reports up to 30 days thereafter. This change accommodates the time normally necessary to prepare those reports and the request. The Administrator's review will take place within 120 days of receipt of the complete package. Additionally, if a future audit of the system (a certification report) uncovers a discrepancy or poor performance that requires recertification of the CEMS, the emissions will be determined using the appropriate missing data procedures, prospectively, upon receipt by the owner or operator of the Agency's determination until the recertification testing is successfully completed.

EPA believes that these modifications fully address the commenters concerns while addressing the legislative mandates and insuring the integrity of a CEM system certification.

(2) Recertification

Issues: A number of issues were raised by commenters related to recertification. Among the issues raised was that it was unclear as to what actually triggered the need for a recertification, the time needed to notify of recertification testing, approval time needed, recertification time-frames in the event of an emergency, and the types and numbers of tests required for recertification.

Response: EPA has further clarified the sentence in the proposal that indicated when recertification becomes necessary. Essentially any change, other than routine maintenance or quality assurance activities, that affects the monitors measuring systems or analysis systems in such a way that measurements or calculations have changed, or potentially could have changed significantly, triggers a recertification. The EPA continues to feel that the nature of Title IV and its reliance on strict accountability of all emissions necessitates a reliance on certified measurement devices and calculation methodologies, hence, forcing the agency to require recertification whenever either or both of these items are significantly modified in any particular CEM system.

EPA is persuaded by public comment and analysis that the notification of recertification testing dates should be shortened to 7 business days prior to the commencement of a scheduled

recertification testing period and that in the event of emergency testing (e.g. testing due to significant repairs after a lightning strike or tornado damage to a CEM) notification should be made to the appropriate authorities no later than 2 working days following the emergency and indicating when testing is expected to be completed. EPA believes that this compromise addresses the commenters concerns about monitor availability and the long lead times that would put data obtained during this time into an uncertain state as to acceptability while also preserving the needs of the regulating authorities to be aware and available for a cooperative effort to recertify as quickly as possible while preserving the intent of the Act to account for all emissions.

B. Relative Accuracy and RATA Testing

(1) Relative Accuracy Standards for SO_2 and NO_x

(a) Normal emitters. The proposed rule required SO_2 monitors and NO_x monitoring systems to meet a 10 percent relative accuracy (RA) standard in Phases I and II of the Acid Rain Program. Some commenters argued that the 10 percent standard was, at best, premature and, at worst, too stringent, and that it would result in high failure rates due to the variability of the reference method, leading to wasted resources for retesting. They proposed that the standard should be set initially at 15 percent. Other commenters indicated that the standards were either achievable or not sufficiently stringent.

Response: The EPA analyzed data from relative accuracy test audits (RATAs), conducted during 1984–1990 at non-low-emitting subpart Da units. ("Subpart Da" units refer to electric utility fossil fuel steam generators, covered under 40 CFR part 60, subpart Da of the New Source Performance Standards (NSPS).) This analysis indicates that SO_2 CEMS, measured in ppm, achieved the 10 percent standard in 89 percent of the RATAs, even though meeting a 10 percent relative accuracy standard was not required. Extensive field tests at one unit confirmed these results. In relative accuracy testing performed over a 9 week period, the installed SO_2 CEMS, measuring in ppm, passed the 10 percent RA standard in 98.2 percent of the RATAs constructed from 176 runs conducted at the test site. These results were obtained by moving a 12-run window through the 176 runs and applying the test procedures prescribed in the proposed regulations. For each incrementing of the window, relative accuracy results were computed, producing a total of 165 RATA tests for the entire data stream. This procedure revealed that 95.8 percent of the RATAs achieved RA ≤7.5 percent, and 82.4 percent of the RATAs achieved RA ≤5 percent. Comparable results for the NO_x CEMS measured in lbs/MMBtu were 100 percent achieving RA ≤10 percent; 97.6 percent achieving RA ≤7.5 percent; and 86.7 percent achieving RA ≤5 percent. EPA believes that these test results support the proposed 10 percent RA standards for both SO_2 and NO_x, which are retained in the final rule.

(b) Low emitters. For SO_2 concentrations less than or equal to 250.0 ppm, the proposed rule allowed use of an alternative accuracy standard: The mean of the CEMS measurements had to be within ±15.0 ppm of the reference method mean. Commenters pointed out that low emitting units should have the option of using either the normal relative accuracy standard or the alternative standard. They also noted that the low emitter accuracy provision should be added to the "out-of-control" provisions in appendix B.

Response: EPA agrees. For units whose monitor measurements of SO_2 during the RATA are close to 250.0 ppm, the ±15 ppm specification could represent a more stringent standard than the 10 percent RA specification. This is not intended. Therefore, the final rule clarifies that either the low SO_2 emitter accuracy standard or the normal SO_2 RA standard can be used. As the commenters recommended, the low SO_2 emitter accuracy standard has been added to the "out-of-control" provisions in appendix B.

The proposed rule also allowed use of an alternative accuracy standard for NO_x emissions less than or equal to 0.50 lb/MMBtu: The monitoring system mean had to be within ±0.05 lb/MMBtu of the reference method mean. A number of commenters noted that the low NO_x emitter threshold of 0.50 lb/MMBtu must be in error, because it is the same level as the statute's presumptive NO_x limit for wall-fired boilers and is higher than the 0.45 lb/MMBtu limit for T-fired units. The proposed low NO_x emitter threshold would, in effect, define all units affected by the NO_x emission limits as low NO_x emitters.

Response: Clearly, this was in error. In the final rule the low NO_x emitter accuracy standard is revised as follows: For units emitting less than or equal to 0.20 lb/MMBtu NO_x, the NO_x monitoring system mean must be within ±0.02 lb/MMBtu of the reference method mean value. This is analogous to the low-emitter accuracy standard for SO_2. Similarly, the low NO_x emitter accuracy standard has been added to the "out-of-control" provisions in appendix B.

(2) SO_2 and NO_x RATA Frequency

For SO_2 and NO_x CEMS, the proposed role required semiannual RATAs, except when an SO_2 monitor or NO_x monitoring system achieves a RA of less than or equal to 7.5 percent. In such cases, the proposal extended the time period for the next RATA to 12 months instead of six. Many commenters supported the proposed RATA frequency incentive system, which linked decreased RATA frequency to superior RA test results. These commenters suggested expanding the incentive system to include low emitters. There were, however, a number of commenters who categorically opposed requiring a RATA more often than annually, whether there was an incentive system or not. They maintained that more frequent RATAs would not improve the accuracy of CEMS data and would be unnecessarily costly. Still other commenters proposed basing RATA frequency on results of daily calibration error tests rather than on RATA results.

Other commenters supported requiring quarterly RATAs until test results justified less frequent RATAs. One group maintained that RATA tests were snapshots and that a series of tests, over four quarters, showing consistent or steadily improving results was a better indicator of CEMS performance than one RATA per year. This commenter supported a phased approach that would require quarterly RATAs for all Phase I affected units with less frequent testing in Phase II, pending Phase I results. This commenter also recommended adoption of an incentive-based system that would credit and debit allowances, based on a unit's performance compared to the best performers in the industry.

Response: Alter considering the range of comments, EPA has decided to retain the RATA frequency and incentive system as proposed and to provide an analogous incentive system for low-emitters. Extending the incentive system to units where SO_2 concentrations are low should stimulate improved RA, while reducing the frequency, and hence cost, of performing RATAs at these units. As designed, the low SO_2 emitter incentive system should yield the same proportion of less frequent RATAs as the incentive system for normal SO_2 emitters. If a unit's mean SO_2 concentration is less than or equal to 250.0 ppm and within ±8.0 ppm of the reference method mean, the next required RATA test would be required in 12 months rather than six.

The Agency decided not to base the RATA frequency on the daily calibration error test results, as suggested, because calibration error tests do not test CEMS for many potential sources of error, making them an inappropriate basis for determining RATA frequency. EPA also rejected the suggestion of universal or phased-in quarterly RATAs, as imposing a greater financial and regulatory burden on industry than necessary, without significantly improving the accuracy of the emissions data. Finally, the allowance-based incentive system proposed by one commenter appears to be a promising approach but would be too complex and difficult to implement, particularly considering the time requirements imposed by statutory deadlines.

(3) Combined SO_2-Flow

The proposed rule stipulated that, starting on January 1, 2000, the combined SO_2-flow monitoring systems would have to meet a 10 percent RA standard. Many commenters criticized this proposed combined relative accuracy test. These commenters stated that because each monitor is required to also pass QA/QC tests individually, the combined RA is merely a mathematical exercise, which, judging from existing data, is technically insupportable and likely to yield erratic and meaningless results. These commenters also maintained that the combined RA test was redundant, unnecessary, and could lead to expensive and needless re-testing. Others argued that the 10 percent combined RA standard may not be achievable in light of measurement errors associated with reference method procedures and that any future combined SO_2/flow RA standard should not be less than 20 percent. One commenter stated that the proposed 7-day certification test for the combined SO_2/flow system would be costly and impossible to pass. Several other commenters recommended that EPA defer promulgating a combined SO_2/flow RA standard until more data was obtained.

However, supporters of the combined RA test were numerous. These commenters maintained that the combined standard would result in more accurate data. Among their proposals were starting the requirement in 1995 rather than in 2000, requiring a combined SO_2/flow RA standard more stringent than 10 percent in Phase I so that the allowance system would not be compromised, requiring a lb/hr RA for SO_2 and a lb/MMBtu RA standard for NO_x, rather than individual monitor RA's, and establishing an alternative combined standard for low emitters.

Response: EPA believes that both individual SO_2 and flow monitor measurements and combined lb/hr SO_2 values derived from those measurements should meet explicit and verifiable accuracy standards. Flow monitor data should meet accuracy standards because, in addition to lb/hr calculations, it is used: (1) In calculating heat input (for reduced utilization), (2) for missing data procedures, and (3) for calculating NO_x penalties. SO_2 monitor data should meet accuracy standards because, in addition to lb/hr calculations, it is used for missing data procedures. The lb/hr values should meet accuracy standards because they are the ultimate measure of environmental impact and the basis for determining compliance with allowances held.

At the same time, EPA agrees with comments noting that there is currently insufficient data to establish a definitive combined SO_2/flow relative accuracy standard. Therefore, EPA is deferring promulgation of a specific combined relative accuracy standard in the final rule, while reserving a section in part 75 for future promulgation of this standard once sufficient data has been accumulated. EPA believes that a combined SO_2/flow RA requirement is an important additional indicator of system performance.

Twenty percent relative accuracy is widely acknowledged as an achievable baseline standard for combined relative accuracy performance, that is in keeping with the combined standard established in EPA's Performance Specification 6 (Appendix B, 40 CFR part 60). Preliminary test data from state programs employing Performance Specification 6 indicate that combined relative accuracies below 10 percent are routinely achieved. In addition, simulation analysis shows that units whose flow and pollutant concentration monitors individually achieve relative accuracies of 10 percent or better almost invariably will meet a relative accuracy standard of 15 percent on the combined test. The EPA is fully committed to promulgating a combined standard once sufficient data has been obtained and evaluated under Phase I of the Acid Rain Program.

(4) Bypass Flues and Peaking Units

The proposed rule would have subjected CEMS on bypass flues and peaking units to the same RATA frequency (quarterly, semiannual or annual) as those on normal stacks and baseload units. Several commenters argued that CEMS on bypass stacks should only have to perform annual RATAs. These commenters also suggested defining RATA testing frequency in terms of unit operating hours, rather than calendar time, and postponing RATAs until the bypass stack was next called into regular operation. Another commenter stated that the final rule should not require a unit to be operated or a pollution control system to be bypassed just to conduct a RATA, since this would result in unnecessary emissions and loss of allowances and might cause a unit to violate its operating permit.

The same commenters and several others noted that it would be very expensive and create needless pollution to run low capacity factor "peaking" units just to conduct RATA tests. These commenters recommended basing a peaking unit's RATA frequency on unit operating hours and performing RATAs on peaking units every two operating years.

Response: EPA agrees that it is not desirable to require a pollution control system to be bypassed solely to perform a RATA. However, the statute requires monitoring of emissions from all affected units and enforcement of performance standards that guarantee accurate emissions measurement.

To reduce the overall time required to perform RATAs on monitors at peaking units and bypass stacks, the final rule requires only a one-level RATA to be performed on flow monitors on peaking units and bypass flues instead of the usual 3-level RATA. EPA believes that it should be possible to schedule RATAs during the normal operation of peaking units and bypass stacks through careful advanced planning.

C. Bias Test and Bias Adjustment Factor

Accuracy in emissions measurements is essential to the complete accounting of all SO_2 and NO_x emissions reductions, stipulated in the Clean Air Act Amendments, and to the effective functioning of SO_2 allowance trading. Consequently, the acid rain regulations proposed that each CEMS satisfy two complementary statistical tests for accuracy both at initial certification and during periodic quality assurance performance evaluations: (1) A relative accuracy test to ensure that all sources of monitor error (both random and non-random) fall below a specified percentage of the average reference method measurements; (2) a bias test to determine if a monitor is measuring consistently low. These two tests are applied to emissions data obtained during the relative accuracy test audit (RATA), a field test procedure that compares at least nine monitor

measurements to contemporaneous measurements by an EPA specified monitoring reference method.

To determine whether a CEMS is measuring consistently low, the bias test relies on the well-established t-test at 95-percent confidence level, applied here to low bias only. The t-test, specified in these regulations, is constructed to ensure that there is at most a 2.5 percent probability of mistakenly detecting low bias during the RATA test.

When low bias is detected, operators have two options: they can remedy the causes of the low bias by fixing a faulty monitor, correcting installation problems, or improving operator practices that may be contributing to the consistently low measurements. Alternatively, they can elect to apply a bias adjustment factor to subsequent emissions measurements reported to EPA. The bias adjustment factor is a multiplier, calculated from RATA data, whose magnitude is directly proportional to the degree of low bias detected during the RATA performance test.

(1) Bias Test

(a) Overview. The EPA received comments both supporting and criticizing the proposed bias test. Numerous commenters supported the proposed bias test as an essential element of a monitoring program. Many others proposed dropping the bias test, arguing that daily quality control procedures offered sufficient safeguards against monitor bias. Still others supported a t-test for bias, but advocated that it be based on data from the daily calibration error test rather than from the RATA test. Some of the commenters, who either opposed the bias test entirely or proposed basing it on calibration data, also advocated applying the RATA-based bias test only at initial monitor certification. Subsequently, they would rely exclusively on quality control procedures or the calibration-based bias test to prevent low bias. Another proposal, by the commenters advocating the calibration-based bias test, was to drop all bias testing requirements when relative accuracy test results fell below some threshold value.

Response: After carefully evaluating each commenter's proposal, data provided by the commenters, data independently collected by EPA, and statistical theory, EPA has decided to retain the proposed t-test for bias and the bias adjustment factor. The EPA's analysis of the specific comments on the bias test is summarized below.

(b) Long-term validity of bias test. Some commenters challenged the ability of a t-test, based on a 4–8 hour RATA, to determine whether a CEMS was producing consistently low measurements (i.e., bias) over the long run. They maintained that a bias test, based on RATA data, was only a snapshot that would produce inconsistent results if performed on the same monitor on successive days. To support their argument, they provided bias test results from two plants.

Response: The EPA found one of the commenter's data sets inadequate. EPA believes that the data was not sufficiently extensive to support the commenter's argument, since it consisted only of a total of six RATAs: Two successive RATAs conducted on August 18–19, 1987, May 26–27, 1988, and September 20, 22, 1988. Further, there was insufficient documentation to determine whether the variability in the test results was due to the test procedure or factors that may have introduced bias into the system. To analyze the long-term variability of bias test results, the factors subject to variation must be strictly controlled or, at least, documented. If factors such as monitor location, operating procedures, and unusual interventions (e.g., lightning strikes) vary from test to test, then variations in test results may not reflect variability inherent in the statistical test but variability in the monitoring environment that may have produced systematic error reflected in the bias test results. Without additional documentation it is not possible to determine whether changes may have occurred that could have introduced bias into the system.

The second set of bias test results cited by the commenter contradicts the commenter's contention: the same flow monitor consistently failed the bias test in RATAs performed on four successive days. While the commenter argues that the test results show that the bias adjustment factor is "unstable," the results clearly do not support the commenter's position on the variability of bias test results.

The t-test is a well established and widely accepted statistical procedure for detecting bias. As noted above, the statistical premises underlying the form of the t-test specified in the regulations limit the likelihood of mistakenly detecting low bias to no more than a 2.5 percent probability. Thus, a high degree of assurance is built into the test itself that, over the long run, this statistical test will detect bias that is actually present in the system, not "random measurement error" as the commenter claims.

In the preamble to the proposed rule, it was noted that EPA collected and analyzed data from RATAs performed between 1984 and 1990 primarily at units subject to Subpart Da requirements and found that 70 percent of the SO_2 RATAs, measured in ppm, passed the proposed t-test for bias. These results were obtained from RATAs performed at a time when CEMS technology and operational experience were in an earlier stage of development than they are today.

An extended field test at one unit also reflected consistency in the bias test results. Following the calculation procedures prescribed in the proposed regulations and moving a 12-run window through a 176-run data stream, 165 RATAs were produced for the 9-week testing period. The bias test pass rate was 73.3 percent for the SO_2 CEMS, measured in ppm, and 99.4 percent for the NO_x CEMS, measured in lbs/MMBtu. Bias test failures were clustered, not randomly distributed, along the data stream, providing a further indication that the t-test was detecting actual systematic error, not random measurement error. It is also noteworthy that 98.2 percent of the SO_2 CEMS and 100 percent of the NO_x CEMS passed the 10 percent relative accuracy test.

In the preamble to the proposed rule, EPA noted that "it can be assumed that subsequent improvements in monitor technology will yield even better performance on the bias test." RATA data, submitted to EPA for a new CEMS technology, based on ultraviolet/differential optical absorption spectroscopy, convincingly supports this prediction and displays consistency in the bias test results. Of the 16 RATAs performed on this monitoring system, 87.5 percent passed the bias test, while achieving an average relative accuracy of 6.9 percent.

Thus, EPA believes that both statistical theory and field test results show that the bias test is a sound and effective statistical procedure for detecting consistent measurement error in the long-term operation of a CEMS.

It should be noted, however, that EPA is sympathetic to the commenter's concern that data used in the bias test be "sufficiently representative of long-term monitor performance." From a strictly statistical standpoint, the larger the sample size, i.e., the longer and more frequent the RATA, the more representative the RATA will be of long-term monitor performance. For this reason, EPA considered requiring quarterly RATAs in all cases. However, the agency chose to balance statistical considerations against the burden

imposed on the regulated community. The agency believes the 9-run RATA supports statistically credible results at the least cost to society.

(c) Impact of reference method variability on the bias determination. Some commentators argued that inherent variability in the reference method performance could inappropriately cause CEMS to fail the bias test even when the CEM measurements were not biased relative to the true emissions concentration. They argued that the variability among reference monitors should be accounted for by adjusting the t-test. The potential for a CEMS to fail the bias test by being compared to a certified reference monitor was investigated in the above referenced field study. In this study, RM measurements were taken simultaneously by four laboratory test teams, and compared with an operating plant CEM. The field results demonstrated that the low bias test results were consistent, regardless of the particular reference monitor chosen. Further, the variation associated with RM-to-RM comparisons exhibited good reproducibility, suggesting that laboratory variability did not inappropriately influence the bias determination. This result is encouraging, and strongly supports the choice of the RMs and its use. However, detailed review of the RM data produced some troublesome results that warrant concern. While the variance across RMs relative to the mean difference in RM readings was low, bias could be calculated between the different reference monitors (in as many as 50% of the comparisons). Concern has been expressed that the high frequency of bias in comparisons among reference monitors occurred despite the reproducibility of results among reference monitors noted above because of low variance in reference method test data. Additionally, some commenters expressed concern that bias was triggered at lower emissions levels (below 200 ppm).

While the Agency currently supports the bias test, the data suggest that further study is appropriate. The Agency, in consultation with the Department of Energy, will initiate additional field studies as soon as possible to determine whether there are statistically significant variances in the reference monitors. These field studies will attempt, among other things, to distinguish between the variability in the reference monitor reading attributable to measurement error and the variability due to the choice of reference moritor among those certified by the agency. The studies will also assess whether any adjustments indicated are technically unnecessary or infeasible to properly determine bias. Finally, the field studies will also investigate possible differences in bias test failure rates by emissions concentration levels. The Agency will initiate the field studies as soon as possible to determine whether the bias test should be adjusted to compensate for statistical variances in the reference method. These studies will be completed by October 31, 1993. Within 90 days of the completion of the studies, the Administrator shall publish by notice of proposed rulemaking in the **Federal Register** his determination of whether there should be an adjustment of the bias test. The rulemaking shall be completed within 9 months thereafter. EPA will also adjust the t-test used to certify alternative monitoring systems if a bias t-test adjustment is made.

(d) Statistically significant vs. practically significant measurement differences. Some commenters argued that the paired t-test may identify measurement differences between the CEMS and reference method that are statistically significant but that are not necessarily practically significant.

Response: The fact that the bias adjustment factor is directly proportional to the magnitude of the measurement differences ensures that sources will not be unfairly penalized for differences that are not practically significant. If, as the commenter contends, the measurement differences are not practically significant, then it follows directly from the commenter's argument that the bias adjustment factor will not be practically significant, and, consequently, the adjustment of subsequent measurements will also not be significant.

(e) Bias test results for volumetric flow monitors. Several comments specifically questioned the application of the bias test to flow monitors. They maintained that the proposed bias test was beyond the current capabilities of volumetric flow monitors. They noted that less than 30 percent of the RATAs in EPA's pre-proposal flow monitor database passed the bias test.

Response: A number of utilities have subsequently provided EPA with field test results from 56 additional flow monitor RATAs, bringing the total number of RATAs in the database up to 73 from the original 17. In evaluating the tests included in this database, several considerations are relevant. The flow monitors in this database were not long-standing installations, but were still in a shake-down phase where various utilities were evaluating competing brands in anticipation of purchasing one of them. Thus, several competing flow monitors were installed on a single stack and put through their paces under extreme testing conditions, without the benefit of installation fine-tuning that would accompany an actual installation. Shake-down testing of this kind produces poorer test results than can be expected when the selected monitor is finally installed and many of the problems that emerged during shake-down are corrected. Furthermore, because gas stratification is so important in measuring volumetric flow and each site has a unique stratification profile, flow monitor performance tends to be very installation specific. As a result, it is not uncommon that one monitoring technology performs well at one unit, while a different technology is better suited for another unit.

With this in mind, it is noteworthy that at each utility unit where multiple brands of flow monitors were tested, at least one flow monitor model had a bias test pass rate of better than 80 percent. In fact, at four of the five utilities testing multiple brands of flow monitors, at least one monitor model had a 100 percent pass rate on the bias test. Excluding one manufacturer's monitor that appears to have had recurring difficulty eliminating low bias, 65.1 percent of the remaining 43 RATAs passed the bias test.

These test results provide additional support for EPA's conclusion that the bias test performance standard is within the technical capabilities of current flow monitoring technology.

(f) Exemption from bias test. Some commenters proposed retaining the bias test but exempting units that achieve excellent results on the relative accuracy test.

Response: EPA does not support this suggested exemption. Under the proposed regulations, units were already rewarded for excellent relative accuracy results by being allowed to perform less frequent RATAs. Because bias represents systematic rather than random error, it is correctable and, therefore, should be eliminated to ensure that the monitoring program provides the level of accuracy required for compliance with the emissions standards mandated by the Clean Air Act Amendments and for effective functioning of the allowance trading program.

Furthermore, waiving the test for low bias could have serious environmental consequences even when relative accuracy is very low. As its name implies, relative accuracy reveals the proportional relationship between inaccuracy in the CEMS and the average emissions level of the unit being tested.

For high emitters, e.g., units whose mean SO_2 emissions concentration could measure as high as 3000 ppm, the absolute magnitude of the inaccuracy may be environmentally significant, even though its relative size (i.e., the relative accuracy) is small. Thus, excellent relative accuracy can obscure the presence of environmentally consequential and operationally correctable inaccuracy that only the bias test will reveal.

(g) Daily calibration error test and periodic quality control (QC) instead of the bias test. One commenter called for replacing the proposed bias test with "the daily calibration error test and periodic QC."

Response: EPA supports the use of the calibration error test and periodic QC as important components of a comprehensive quality assurance/quality control (QA/QC) program. However, by themselves QA/QC procedures and calibration testing can neither detect nor eliminate many important sources of bias. For example, calibration testing is unlikely to detect bias attributable to incorrect calibration gas values, uncorrected sensitivity to pressure and temperature, non-representative sampling, interferences from flue gas constituents, or scrubbing by precipitates on the particulate filter. Without a means to detect these sources of bias, QA/QC procedures would be blind to their presence and would be unlikely to correct the problem. Only the RATA-based bias test, which compares the installed CEMS to an independent reference monitoring method under actual operating conditions, can detect all major sources of systematic measurement error that constitutes bias. If the calibration and QA/QC procedures proposed by the commenter are conscientiously implemented in concert with periodic RATA-based bias and relative accuracy tests, monitor accuracy as required by the Clean Air Act Amendments should be achieved.

(h) Calibration-based bias test and adjustment factor. As an alternative to the RATA-based bias test, some commenters proposed retaining the one-tail t-test but applying it to data obtained from the daily calibration test instead of data from the periodic RATA. They supported their proposal by noting that the pass-fail rates on the two tests are comparable. In addition, they noted that the bias adjustment resulting from their alternative bias test was substantially lower on average than that adjustment factor derived from the RATA-based test.

Response: The suggested calibration-based bias test is flawed on engineering and statistical grounds. Two problems with a cal-gas based bias test from an engineering standpoint are its lack of an independent test procedure and failure to detect all sources of bias. First, to objectively quantify CEMS accuracy requires an independent test. That is, the standard against which the CEMS is checked should share no components in common with the CEMS. For the RATA test, where the reference method shares no components with the installed CEMS, this condition holds. In contrast, the calibration test is not an independent test, since the same CEMS used to perform emissions measurements is also used to measure calibration gas concentration. Second, the cal-based bias test is capable of detecting only a few of the potential sources of CEMS bias. The cal-based test should be able to detect bias caused by electronic/optical drift, improper interfacing of the analyzer and the data acquisition system, and loss of gas by absorption or adsorption. It may be able to detect bias caused by system leaks and plugging and by improper microprocessor corrections. However, it is unlikely to be able to detect bias caused by incorrect calibration gas values, uncorrected sensitivity to pressure and temperature, non-representative sampling, interferences from flue gas constituents, or scrubbing by precipitates on the particulate filter. In essence, the cal-based bias test simply detects consistent daily electronic/optical drift and operator introduced error, not full system bias.

From a statistical perspective, there are several serious drawbacks to use of the cal-gas based bias test. First, because the calibration procedure adjusts the CEMS based on the previous day's drift, the test procedure itself introduces time dependencies into the data, possibly limiting the applicability of the t-test. This contrasts with the RATA-based bias test. While the process being measured may display time dependencies, the RATA-based test procedure is unlikely to introduce time dependencies into the data.

Second, if the calibration procedure is not completely automated and an operator adjusts the CEMS each time a calibration is performed, it is difficult to determine whether the t-test is picking up bias in the installed CEMS or systematic error introduced by the operator's role in the test procedure. Unlike the RATA-based bias test, where the test protocol and reliance on an independent reference method minimize the chance of systematic error being introduced by the tester, there are no such inherent procedural safeguards in the cal-gas bias test. An operator's intervention in the calibration test also raises the possibility of obscuring of bias through over-adjustments of the daily measurements on which the bias test depends. For example, if an operator repeatedly over-adjusts up one day and over-compensates low the next day, the presence of bias is likely to be hidden by the oscillating over-adjustments.

Besides these problems with the cal-based bias test, the commenter's observation that the cal-based test's pass/fail rate is close to the pass/fail rate on the RATA-based bias test is irrelevant. The two tests are measuring two different phenomenon, which are not necessarily correlated. Any closeness of pass/fail rates is therefore likely to be purely coincidental.

(i) Performing RATA-based bias test only at initial certification. Some commenters proposed that the RATA-based bias test only be performed at initial certification of the CEMS. Some of these commenters proposed using a bias test based on daily calibration data after certification; others proposed using the calibration error test and routine quality control procedures to prevent bias.

Response: While it is particularly important to perform the RATA-based bias test at initial certification of the monitor, when many installation-related sources of bias can be detected and overcome, periodic RATA-based bias testing is equally important after installation, because it represents the only reliable way to detect and correct bias that can arise once the CEMS begins operation. Routine occurrence (like precipitate buildup on the probe) and unpredictable events (like lightning strikes) can cause installation and operating conditions to change over time, and these changes can cause monitor bias which could go undetected without periodic RATA-based bias testing. As explained above, neither calibration error testing nor bias testing based on calibration data can detect many of the major sources of bias that arise during initial installation or extended operation. EPA believes that periodic RATA-based bias testing is the most reliable way to determine whether bias has developed in the monitoring system.

(2) Bias Adjustment Factor: Comments and Responses

Comments for and against the proposed bias adjustment factor were about evenly divided. Many commenters supported the adjustment as an important element in an effective, yet flexible, monitoring program. Many others recommended dropping the bias adjustment factor and emphatically

stated that bias test failure should not result in the monitor being designated "out of control," as was once contemplated, but not subsequently proposed, as an alternative to the bias adjustment. A number of commenters proposed variations on how the adjustment should be computed and when it should be applied.

(a) Technical justifiability of the adjustment factor. Some commenters contended that the bias adjustment, based on the RATA test, is technically insupportable. In part, their position rests on the argument, summarized above, that the RATA-based t-test itself is not an appropriate measure of bias. Furthermore, the commenters maintained that an adjustment factor derived from a nine-run RATA "would result in an artificial inflation of reported emissions that would remove SO_2 allowances from the marketplace."

Response: It should be noted that the adjustment factor is a regulatory mechanism intended to add flexibility to the performance testing program. The adjustment factor gives units an alternative to eliminating the sources of bias, while minimizing the likelihood that emissions measurements will be under-reported. When low bias is detected by the t-test, a source can choose either to find the cause of the problem and fix it or to adjust subsequent emissions measurements by a factor commensurate with the extent of bias detected at the time of the RATA. Deriving the bias adjustment factor directly from the RATA results means that there is no "artificial inflation," over-compensation, or conservativeness involved, because it reflects conditions exactly as they are at the time of the RATA.

EPA's analysis indicates that the average bias adjustment factor is likely to be below 5 percent. In the SO_2 lbs/MMBtu RATA database, the average bias adjustment factor was 4.4 percent for RATAs that met the RA≤10 percent relative accuracy requirement but failed the bias test. For these RATAs the adjustments ranged from 0.89 percent to 6.99 percent. Thus, the bias adjustment factor would appear to provide utilities with a reasonable and practical alternative to repair a low biased CEMS.

(b) Bias adjustment factor for high bias as well as low bias. Some commenters proposed that the bias adjustment factor should not only be applicable to monitors that measure consistently low (i.e., low biased CEMS), but also to those that measure consistently high (i.e., high biased CEMS).

Response: EPA believes this modification is neither necessary nor desirable. As proposed in the regulations, the bias adjustment factor provides an incentive for eliminating low bias, comparable to the financial incentive that the allowance market gives to eliminating high bias. In tandem, these twin incentives will provide a self-enforcing mechanism, virtually free of regulatory intervention, for minimizing monitor bias—both high and low. An adjustment for high bias would remove the self-enforcing market incentive for eliminating high bias and require the imposition of a more burdensome administrative procedure for controlling high bias. There is also no environmental justification for an adjustment factor for high bias.

(c) Bias adjustment for flow monitors. A number of flow monitor vendors expressed concern that bias test results and the corresponding bias adjustment are likely to vary substantially at the three different load levels required for the flow monitor RATA test. It was feared that requiring a bias adjustment factor to be derived only at the normal load level might inadvertently distort monitor accuracy at other load levels.

Response: The bias adjustment factor specified in the proposed regulations is not a mechanism for calibrating the flow monitor to the reference method over the load range. Such a calibration procedure can be incorporated into a manufacturer's proprietary instrumentation, for example, by means of a regression curve, as suggested by one vendor. Rather, the bias adjustment factor is simply a regulatory mechanism, giving sources an alternative to eliminating the causes of bias, while minimizing the likelihood that flow measurements will be under-reported. EPA requires the flow monitor bias test to be computed only on the RATA data collected at the normal operating level. However, if the bias test is failed at normal load, the bias adjustment to be applied to subsequent data are the largest of the adjustments derived from the low, normal, and high-load RATAs. This should avert under-reporting of flow measurements, in light of the commenters' contention that the magnitude of the bias adjustment factor may not be uniform across load levels. In addition, during Phase I of the Acid Rain Program, EPA will analyze data from the low- and high-load RATA tests to see if bias test results at these loads would have diverged substantially from those obtained at the currently required normal load level and will continue to evaluate the bias test requirements for flow monitors.

The extensive analysis of comments on bias described here has led EPA to conclude that the RATA-based bias test and the bias adjustment factor are sound and essential elements in a performance testing program for assuring the accuracy of CEMS. Unlike other alternatives proposed, the RATA-based bias test provides a procedure for detecting systematic error that tests the full system against an independent reference method monitoring system under actual operating conditions. In tandem with the bias adjustment factor, this procedure represents a cost effective and self-enforcing mechanism for eliminating systematic error from monitoring systems.

D. Flow Monitors

Commenters raised seven major issues related to flow monitoring. Three pertained to the RATA (relative accuracy test audit) for flow monitors: Proposed changes to the relative accuracy standard; the requirement that RATAs be performed at three load levels; and the required frequency of RATAs. In addition, commenters charged that there was not a "level playing field" for all flow monitor technologies, asserting that the proposed calibration test for flow monitors was discriminatory against specific technologies. Commenters also questioned the need for an orientation sensitivity test. There were also comments on the proposed definition of "span" for flow monitors. Finally, there was a comment on the petition process for alternative monitoring locations for flow monitors.

(1) Relative Accuracy Standards

The proposed rule required that flow monitors meet a 15 percent relative accuracy (RA) standard through December 31, 1999 and a 10 percent RA standard thereafter. Because the mathematical structure of the RA statistic makes it very difficult to achieve the 10 percent RA standard when the flow rate is low, the proposed rule would have allowed flow monitors to be within ±1 foot per second (fps) of the reference value, rather than achieving 10 percent RA, when the flow rate was less than or equal to 10 fps.

EPA received many comments regarding the proposed flow monitor RA standards. Some commenters maintained that the proposed flow monitor RA standards were too stringent and could not be supported with EPA's limited database. Some of these commenters also claimed that the proposed RA standards were beyond the capabilities of current flow monitoring technology. Several commenters suggested extending the 15 percent RA standard through Phase II; two other

commenters proposed a 20 percent RA standard throughout Phases I and II.

However, other commenters stated that the proposed flow monitor RA standards were not stringent enough. They asserted that a 10 percent standard for Phase I was clearly achievable based on the evidence cited in the preamble to the proposed rule. One commenter stated that a 15 percent RA standard was very liberal, while another claimed that the flow monitor Phase I RA standard could be tightened to better than 5 percent.

Response: Eighty-two percent of the 73 RATAs now in the EPA database pass a 15 percent RA standard, and 70 percent pass a 10 percent standard. The EPA believes that these test results justify retention of the proposed RA standards in the final rule, except the low flow standard, which is discussed below.

Some commenters urged EPA to change the low flow accuracy standard from ±1 fps to ±2 fps and to clarify that a unit with low flow conditions may apply either the low flow accuracy test or the standard RA test.

Response: Upon further consideration of the measurement capabilities of flow monitors, EPA has decided to accept the commenters' suggestion to change the low flow accuracy standard to ±2 fps for flows less than or equal to 10 fps. The final rule will also make it clear that in low flow situations, units can satisfy their relative accuracy requirements by achieving either the ±2 fps specification or the applicable RA standard. The EPA believes that this change better accommodates the low flow thresholds of current flow monitoring technologies and should prevent unwarranted RATA failures.

(2) Three-Level Relative Accuracy Test

The proposed regulations would have required the operator to perform separate relative accuracy tests on flow monitors at low, normal, and high flow rates or at low, normal, and high unit operating levels. The three-level relative accuracy tests were to be conducted at the initial certification of the flow monitor and annually thereafter as part of the quality assurance performance requirements for flow monitors.

Two commenters supported the concept of an annual 3-level audit for flow monitors. Others suggested that the 3-level flow monitor RATA not be performed annually, but only (1) at certification and (2) when a change in stack/duct configuration necessitated recertification of the monitor. To support their position, these commenters cited the additional testing costs of multiple RATAs, the small likelihood that the flow profile would change absent stack/duct changes, and the potential interference of the multi-level requirement with the economic dispatch of electricity.

Response: EPA's analysis shows that numerous conditions may arise after siting, installation, and certification of a flow monitor to change a flow profile. These include: in-leakages or out-leakages in ducts or stacks, complete or partial disintegration of dampers or straightening vanes, stack or duct blockages due to caking, and changes in fan performance. These changes can occur without necessarily triggering recertification, yet can affect flow monitor performance. The EPA believes that only the annual 3-level audit can determine whether monitor performance has been significantly adversely affected by such changes since certification.

While EPA expects that the cost of 3-level relative accuracy tests will be somewhat higher than a 1-level test, the marginal cost of performing the two additional RATAs should be modest if all three tests are performed consecutively. This will ensure that two major costs will remain one-time expenditures for all three RATAs: the cost to transport the test team to the site and the cost of setting up and breaking down the test equipment. Annual RATA tests can be planned months in advance and scheduled to integrate into economic electric dispatch. Thus, EPA anticipates that utilities should be able to maintain adequate electrical generation in the affected area during the 3-level testing through planned dispatching arrangements.

Based on this assessment, the final rule retains the annual 3-level flow monitor RATA requirement. However, it broadens and increases the flexibility in defining each of the 3 test levels and clarifies the RATA testing requirements for flow monitors installed on common stacks.

(3) RATA Frequency

The proposed rule specified quarterly, semiannual and/or annual RATA frequency, depending on whether the flow monitor performed a daily electronic drift test or a calibration error test and on the relative accuracy level achieved. Monitors that performed a daily drift test, instead of a daily calibration error test, and obtained relative accuracy results greater than 10 percent were required to perform quarterly RATAs.

(a) Quarterly RATAs. Some commenters stated that quarterly RATAs were unreasonable and excessive for any flow monitor that is checked daily. Other commenters favored the calibration error test over the electronic drift test, arguing that the calibration error test was more meaningful. One commenter recommended dropping the electronic drift test option entirely. Nevertheless, most commenters supported the proposal to reduce RATA frequency for flow monitors achieving superior relative accuracy and stated that the proposed reduced frequency reward system would provide an incentive to maintain and improve CEMS performance. In contrast, one commenter opposed reducing RATA frequency to less than quarterly and suggested an incentive-based system that would credit and debit allowances by indexing the relative accuracy standard to the best industry performers.

Response: After carefully considering the range of comments on RATA frequency and criticisms of the electronic drift test, EPA has decided to delete the proposed requirement of quarterly RATAs and the option of performing an electronic drift test in place of the calibration error test. At the same time, as discussed in section 4 below, the final rule expands the allowable procedures that can be followed in performing calibration tests on flow monitors. Field studies and equipment specifications show that all major flow monitor technologies should now be able to perform the calibration tests as specified in the final rule. The EPA believes that the elimination of the electronic drift test and the addition of expanded calibration test procedures should assure daily indication of proper operation of all flow monitors as intended in the proposed regulations. Therefore, because of the deletion of the less credible electronic drift test, which needed quarterly RATA frequency, EPA believes semi-annual RATA frequency is now sufficient.

EPA rejected the proposal to credit and debit allowances. Although the proposal has merit in encouraging better RATA performance, EPA believes it would be administratively complex and difficult to implement.

(b) Frequency incentive under low flow conditions. Other comments on RATA frequency pertained specifically to low flow situations. Commenters argued that under low flow conditions the RATA frequency incentive system was inapplicable because of technological limits on achievable accuracy when flow rates drop below 10 fps. The commenters proposed that under low flow conditions, regardless of the accuracy achieved, RATAs should be performed on the least frequent basis

required for that type of flow monitor, i.e., annually for those performing a calibration error test and semiannually for those performing an electronic drift test.

Response: EPA believes that the proposed reduced RATA frequency incentive system is practical at low flow rates because of the new low flow accuracy standard of ±2 fps, described above. Consequently, EPA is extending the RATA frequency incentive system to low flow rate conditions. Under such conditions, flow monitors will qualify for reduced RATA frequency when the flow monitor mean is within ±1.5 fps of the reference method mean. Thus, if a flow monitor meets this standard and corresponding incentive thresholds on the other levels of the 3-level RATA, it may perform its next RATA in 12 months rather than six months. Manufacturer specifications for many flow monitors indicate that they are capable of meeting the 1.5 fps standard.

EPA believes that extending the incentive system to low flow conditions will provide the same incentive for improved accuracy under low flow conditions as under normal flow conditions. It should also reduce the required frequency, and hence the cost, of performing RATAs.

(4) Level Playing Field

At the time the proposed rule was drafted only ultrasonic flow monitors were known to be performing calibration error tests on the entire flow monitoring system— from sampling point through and including the data acquisition and handling system. Thus, in the proposed regulations, only ultrasonic monitors were required to perform the calibration error test, while non-ultrasonic monitors could either perform this test or conduct an electronic drift test. However, if they chose the latter, which only checks the stability of the monitor's electronics, not the full system, they were required to perform more frequent RATAs. In addition, the preamble requested comments on a proposal for a modified calibration test procedure for differential pressure monitors, which would be allowed to test from a point outside the stack, rather than from the probe tip, through the data acquisition and handling system.

The proposed flow monitor calibration error test was seen as discriminatory by several commenters, particularly vendors of thermal and differential pressure flow monitors. These vendors stated that the proposed requirements were detrimental to their competitive positions and could drive them out of the market unless the calibration error test were changed. Several ultrasonic and thermal flow monitor vendors supported the calibration error test as proposed. Differential pressure flow monitor vendors supported the modified calibration error test procedure, performed from a point outside the stack, rather than from the probe tip, provided that the probe is regularly. backpurged.

Response: The final rule delineates two acceptable procedures that can be used in performing the calibration error test on any flow monitor: (1) A system check from and including the transducer/transceiver through and including the data acquisition and handling system in combination with daily or more frequent backpurge/probe/transceiver cleaning, or (2) a full system test from and including the sampling point, through and including the data acquisition and handling system. Whichever of these procedures is employed, all monitors are also required to perform an interference check no less frequently than every 24 hours. The interference check is a means to detect and correct plugging, fouling, and malfunctions that could interfere with the calibration test. Field studies and equipment specifications show that each of the three main types of flow monitors (thermal, differential pressure, and ultrasonic) are capable of performing the calibration error test, promulgated in today's rule.

(5) Orientation Sensitivity Test

To ensure that flow monitors would be properly oriented in the gas stream, the proposed regulations included an orientation sensitivity test. Several commenters stated that the orientation sensitivity test was unnecessary and difficult to perform for multi-port or array-type systems. These commenters also suggested that the periodic RATA would detect flow monitor orientation problems.

Response: EPA agrees with the commenters that proper orientation of a flow monitor would be ensured by periodic RATAs. Performing an orientation sensitivity test on installed multi-port or array-type flow monitors may be problematic because of the size and complexity of the installation. Out of these considerations, the orientation sensitivity test requirement has been deleted from the final rule.

(6) Instrument Span

Commenters urged EPA to delete or modify the proposed requirement that the span of the flow monitor be set so that average measured monthly volumetric flow fell between 40–75 percent of span. They maintained that the proposed span requirement might not serve the purpose of ensuring more accurate measurements at the predominant flow rates, because a unit might spend half its time at full load (e.g., during the day) and half of its time at low load (e.g., at night) and thereby meet the monthly average 40–75 percent requirement, while rarely ever actually measuring at 40–75 percent of span. One commenter suggested that EPA change the span requirement to an annual average.

Response: EPA agrees that diurnal changes in load and flow rates commonly occur, making it possible for a flow monitor to meet the proposed monthly average 40–75 percent of span requirement, but only infrequently actually measure flow rates at 40–75 percent of span. The purpose of the proposed span requirement was to (a) ensure that flow monitors would measure the predominant flow rates in the middle third of the monitor's span, (b) minimize full-scale exceedances, and (c) prevent artificially high spans that might diminish the monitor's accuracy at low flow rates.

To meet these goals and, at the same time, be responsive to public comment, the final rule drops the proposed requirement that average monthly volumetric flow fall within 40–75 percent of span. Instead, the final rule defines a "maximum potential flow" value, which is derived from the cross sectional area of the stack or duct where the monitor is located, the maximum heat input of all units feeding into that stack or duct, and the amount of combustion air. This value equals the maximum flow possible for a given stack or duct configuration, assuming all units feeding into the stack or duct are operating at their maximum heat input. The 7-day calibration error test, performed at initial certification, and the daily calibration error test calibrate the monitor on reference values set at 0–20 percent and 50–70 percent of the span. In addition, the final rule requires the span of a flow monitor to be set at 125 percent of the maximum potential flow value. This requirement should prevent full-scale exceedances.

E. Alternative Monitoring Systems

Section 412(a) of the Clean Air Act Amendments of 1990 requires that alternative monitoring systems provide information with "the same precision, reliability, accessibility, and timeliness as that provided by CEMS." The proposed regulations designated certified CEMS as the benchmark for evaluating an alternative's performance. Thus, to demonstrate equivalent

precision, an alternative was required to pass three statistical tests evaluating the CEMS and alternative method in terms of their respective systematic error, random error, and correlation. To meet the reliability criterion, the alternative was required to match a certified CEMS in terms of annual availability and ability to achieve performance specifications and quality assurance requirements. Finally, to meet the accessibility and timeliness criteria, an alternative had to match the CEMS' ability to record requisite emissions data on an hourly basis and report results within 24 hours.

(1) Overview

There were three major lines of comments on the alternative monitoring system requirements. One commenter strongly supported the proposed requirements for alternative monitoring systems as a way to ensure strict adherence to requirements of the Clean Air Act Amendments. Another commenter thought the requirements needed to be strengthened by not only stipulating that alternative monitoring systems provide information equivalent to CEMS, but also that the alternatives meet the same certification and performance test requirements as a CEMS (e.g., in terms of relative accuracy). A third set of commenters criticized the applicability of the statistical tests for precision, the stringency of these tests, the requirement that the alternative be compared to a CEMS, and the timeliness requirement. Another commenter objected to subjecting an alternative monitoring procedure to all of the Appendix B "Quality Assurance and Quality Control Procedures," noting that "meeting this criterion may be impossible."

Response: EPA agrees with the first commenter's position and notes that the second commenter's concerns were accommodated in the proposed regulations. An approved alternative monitoring would be subject to all the relevant Part 75 requirements as a CEMS, including initial certification and periodic performance testing requirements. As stated in the proposed regulations, alternative monitoring systems must satisfy all "the applicable requirements of appendix B" unless the owner or operator can demonstrate to the agency's satisfaction that meeting the requirements is physically or technologically impossible and can document equivalent or superior performance on comparable quality assurance and quality control performance standards. The agency believes that these provisions will ensure equivalency with a certified CEMS while leaving room for new technologies that may employ innovative monitoring methods.

The remainder of this section on alternative monitoring systems presents the agency's response to the concerns raised by the third group of commenters.

(2) Applicability of Statistical Tests

Some commenters argued that the three proposed statistical tests for precision were often inappropriate, because they depended on statistical assumptions that were often not met, namely, that the data are normally distributed and independent over time.

(a) Normality assumption. One commenter cited several studies that found emissions data to be lognormally distributed rather than normally distributed and to exhibit time dependency (also called autocorrelation). To support their argument, the commenter presented 22 paired hourly data points obtained simultaneously at the same monitoring location by two separate test teams, using EPA designated Reference Method 6 for measuring SO_2 concentration. The commenters' analysis found that the data did not support the assumptions of normality and statistical independence.

Response: The EPA's own statistical analysis, conducted to evaluate these comments, contradicts the claim that emissions data are frequently not normally distributed. To evaluate normality, EPA applied two standard tests (Shapiro-Wilk test and Kolmogorov test) in conjunction with visual inspections of Quantile-Quantile plots and histograms of the data. These were applied to the commenter's two data sets and 13 other emissions data sets, containing from 62 to 16,081 data points. All the data sets, except the data from the commenter's Test Team B, were found to be normally distributed as evidenced by their yielding extreme values of the test statistics, unimodal symmetric histograms, and straight diagonal Quantile-Quantile plots.

The disparity in the distributional form of Test Team A's and B's data may indicate a problem in one or both team's implementation of Method 6. Two test teams carrying out exactly the same reference method procedure concurrently at the same location will obtain different measurement values, but they should not obtain data with different distributions, unless the testing procedure was inconsistently applied or some other unrecognized problem occurred.

While EPA's analysis does not support the commenter's contention about the distributional form of emissions data, the regulations have nevertheless been modified to accommodate the possible situation, highlighted by the commenter, where emissions data are lognormally distributed. If such a case does arise, the regulations now allow using a logarithmic transformation to normalize the data before the three statistical tests are applied.

(b) Independence assumption. The commenter also notes that the validity of the statistical tests that are applied to alternative monitoring systems depends on the data being statistically independent over time. The commenter maintains that the assumption of independence is often violated.

Response: EPA finds that the commenter's point merits attention. When data are not independent over time, its variance tends to be understated by standard statistical procedures. An underestimated variance could distort the results obtained on some of the proposed statistical tests. An accepted and theoretically substantiated way to compensate for variance underestimation is to multiply the variance by an inflation factor derived from an autocorrelation analysis of the data. This autocorrelation-adjusted variance is then used in statistical tests that are premised on data independence. The EPA has augmented the statistical tests for alternative monitoring systems with a procedure for computing the variance inflation factor. The final rule identifies the conditions under which the factor would be applied.

(3) Stringency of Statistical Tests

Besides maintaining that the statistical tests were inappropriate, the commenter also argued that they were so stringent that "no alternative monitoring system will likely ever be certified." This claim rests mainly on two arguments.

(a) Argument 1: Two reference methods fail the test. The commenter applied the three proposed statistical tests to the paired data from the concurrently run Reference Methods 6 discussed above. The side-by-side reference methods failed the tests, leading the commenter to conclude that "If two identical, concurrently run Reference Methods * * * cannot pass the alternatives testing, it is highly unlikely that any alternative system evaluated against a Reference Method (or certified monitor) would ever pass."

Response: EPA discounts the credibility of the commenter's analysis, because the underlying data are suspect and the sample size too limited. As

noted earlier, concurrent measurements by two duplicate reference methods at the same test location should not produce data with different statistical distributions: Test Team A's data was normally distributed, while Test Team B's was non-normal. This disparity suggests a flaw in one or both of the test team's implementation of the reference method. Drawing conclusions from such data are questionable, particularly when the conclusions are premised on statistical procedures that require the two data sets to be normally distributed. In addition, EPA believes that the sample size of 22 points is too small to support the commenter's conclusion.

(b) Argument 2: The bias test is so sensitive to "incredibly small" measurement differences between two data sets that it is impossible to pass the t-test. The commenter maintains that the t-test is not practically useful because it detects statistically significant differences that are not practically significant.

Response: EPA believes that inconsistencies in the underlying premises render this argument unconvincing. On the one hand, the commenter asserts that the t-test cannot be applied to the cited Reference Method 6 data, because the paired differences are not normally distributed. Then, ignoring this very stricture, the commenter assumes normality and extrapolates the t-test results from the cited 22 hours of data to 720 hours of hypothesized data, concluding that a mere 2 ppm measurement difference would have caused failure on the t-test at the larger sample size. If absence of normality made it inappropriate to apply the t-test to the 22 hours of actual data, as the commenter claims, then extrapolating these t-test results to 720 hours of hypothetical data seems even more questionable.

To further evaluate the commenter's concerns about the stringency of the alternative monitoring statistical tests, EPA analyzed 30–60 days of hourly field test data from four CEMS installed on a common duct at a coal-fired utility that was assessing various brands of monitors as part of their procurement process. While the CEMS were not certified and this was not a controlled experiment that ensured uniformity in the operation of the four CEMS, the data was adequate to assess the stringency of the three alternative monitoring system statistical tests in a situation where no deliberate attempt was being made to meet the test criteria. Forty-one separate data subsets, containing 30 or more successive days of paired hourly CEMS–CEMS measurements were extracted from the field data. Of these, 26 passed the bias test and 20 passed all three statistical tests simultaneously. Had this been a controlled experiment, it could be expected that the pass rate would have been even higher. In any case, the analysis demonstrates that the three tests are not impossibly stringent, as the commenter claims.

While EPA's analysis does not corroborate the commenter's claim that the proposed standards are unattainable, the data screening and adjustment procedures, discussed in the preceding section should ensure that the statistical tests are fully applicable even when the data are not independent over time. Together with the issues discussed above, these additions to the final rule should address the commenter's concerns about the achievability of the alternative monitoring system requirements. Moreover, EPA believes that by clearly articulating the standards that will be used in evaluating proposed alternatives and by basing these standards on objective and widely accepted statistical tests, the proposed alternative monitoring system requirements should reduce the uncertainty that might otherwise impede technological development.

(4) Testing Against a Reference Method Instead of a CEMS

Several commenters objected to having to install a certified CEMS in order to perform the tests needed to gain approval for an alternative method. They pointed out that there were sites where an alternative was being requested because it was not possible to install a CEMS. They proposed that alternative methods be certified by testing them against EPA Reference Methods.

Response: The Clean Air Act Amendments specifically stipulate that alternative monitoring systems provide information with the same precision, reliability, accessibility, and timeliness as that provided by CEMS. The EPA interprets this as requiring comparison to an actual CEMS. Nevertheless, since the CEMS must be certified prior to and during operation by comparison to the Reference Method, EPA agrees with the commenters that a reference method may be used whenever they are operated to provide the same hourly data that would form the basis of the CEMS to alternative comparison on which the criteria are based. Specifically, the reference method would have to produce 720 hourly emission rates. However, many EPA approved reference methods, like the manual wet chemistry Method 6 for SO_2, are completely unsuitable for the round-the-clock testing required to demonstrate long-term operational equivalency to a CEMS. Often labor intensive, the reference methods were designed to provide a measurement standard for short-term performance tests like the Relative Accuracy Test Audit. EPA believes they are not practical for long-term equivalency testing. Nevertheless, today's final rule allows for the generation of the required hourly emission rate data through the use of reference method testing as well as an actual CEMS to be compared with an alternative monitoring system as specified in the rule.

(5) Timeliness Requirements

Arguing that it is "legally unnecessary and unreasonable as a practical matter," one commenter objected to defining timeliness as the ability to provide hourly data and issue a record of the data for the previous day within 24 hours.

Response: EPA disagrees with the commenter. The market-based regulatory process demands an unprecedented degree of accuracy in the emissions totals that are used to calculate allowances. The more aggregated the measurements, the less verification is possible, and the less will be the assurance of accurate allocation of allowances. Both CEMS and approved alternative monitoring systems must be able to provide data in hourly increments and report data within 24 hours if the Acid Rain Program is to implement effective quality assurance and control procedures, validate emissions data, and correct problems before the end of year allowance/emissions reconciliation. The timeliness requirements are also necessary for the proper functioning of the missing data procedure, which depends on hourly values to ensure that substituted values are derived from verifiable, quality assured historical data. EPA believes that the requirements are practically justified and technologically feasible, as discussed above. In addition, the requirements are not unduly burdensome for the regulated community, being equivalent to those mandated by the Clean Air Act Amendments for CEMS.

F. Missing Data Procedure

Section 412(d) of the Clean Air Act requires EPA to prescribe a method for calculating emissions when valid data are not being supplied by a unit's continuous emissions monitoring system (CEMS) or by an approved alternative monitoring system. To meet this requirement, the proposed regulations established a missing data

substitution procedure, designed to achieve five major goals:

- To encourage the use of CEMS as the primary method for determining emissions and, at the same time, foster effective operations and maintenance programs by putting in place strong incentives for minimizing monitor downtime and maximizing data capture rates.
- To replace missing values with modest estimates when monitor availability has been good and missing data periods have been short.
- To replace missing values with more conservative estimates when monitor availability has been poor and missing data periods have been long.
- To establish a procedure that is automatic in its execution, relying only on the CEMS-generated emissions database, thereby minimizing the need for enforcement actions and supporting the smooth and unambiguous operation of the program.
- To establish a procedure that is readily implementable by all affected units and not administratively burdensome for units or EPA.

The missing data procedure, established to achieve these goals, is a multi-tiered computational routine for deriving a substitution value from the values previously recorded by the monitor. The procedure is based on the premise that the longer the gap in recorded data and/or the lower the annual monitor availability, the more conservative the value to be substituted. In concert, two trigger conditions determine the conservativeness of the substituted value. The first trigger condition is annualized availability, i.e., the percentage of the immediately preceding 8760 unit operating hours in which valid, quality assured data was obtained. (Note that for the purposes of the missing data procedure, there are 8760 hours in a year, 2160 hours in a quarter, and 720 hours in a month.) The annualized availability determines the calculation tier that applies: Monitors whose annualized availability has been good (i.e., 95 percent or better) would employ the calculation options on the top tier where the resulting substitution values are likely to be least conservative. On the other hand, monitors whose annualized availability has been poor (i.e., below 90 percent) would use the calculation options on the lowest tier where the resulting substitution values would be most conservative.

Within each of these tiers, the second trigger condition, the length of the current outage, determines the elements of the calculation routine that will be combined to derive the substitution value. The calculation routine consists of three elements: A calculation method, e.g., average, percentile, or maximum value; a lookback period, e.g., the preceding 720 monitor operating hours or the hour before and the hour after the outage; and an indicator, known as a "bin," of whether the substituted value will be chosen from a pre-defined subset or from all of the values that were recorded during the lookback period. Longer outages trigger combinations of calculation elements that are likely to yield conservative substitution values to ensure that actual emissions will not be underestimated. Thus, a short outage (e.g., 4 hours) might trigger a calculation routine employing the average (method) of the monitored values in the hour before and hour after the outage (lookback), using all the recorded data (i.e., no bins are used). On the other hand, a long outage (e.g., 30 hours) might trigger the maximum (method) of the monitored values in the preceding 720 hours (lookback) for the subset of the previously recorded values falling within the same load range as occurred when the monitor was "down" (i.e., bins are employed).

Tables 1 and 2 summarize the missing data procedure for SO_2, NO_x, and flow as modified in the final rule. The crossed out entries in these tables show elements of the proposed procedure that were changed in response to public comments that EPA received. For example, Table 1 shows that the proposed sulfur content bins have been deleted from the missing data procedure for SO_2 CEMS in response to many comments indicating that the requirement would be very burdensome on affected units. It may be helpful to refer to these tables when reading the following detailed discussion of the public comments and the changes produced in response to them.

EPA received more than 400 comments on various aspects of the proposed missing data procedure. To help evaluate these comments and verify earlier analyses, EPA developed a sophisticated computer simulation model for testing the likely impact of variations of the trigger conditions and calculation routines in the missing data procedure. The model was applied to historic SO_2 and NO_x emissions data from units both with and without emissions controls. Each individual data set contained approximately 10,000 hourly emissions measurements. Sensitivity analysis was performed using both "worst case" and "most likely" scenarios for outage occurrences.

(Note: EPA has requested that Table 1 be printed as shown below. Crossed out entries in this table represent items, originally in the proposed regulations, that were changed in the final version of the regulations.)

TABLE 1.—MISSING DATA PROCEDURE FOR SO_2 CEMS

Trigger conditions		Calculation routines		
Annualized availability (percent)	Duration (N) of outage (hours)	Method	Lookback period	Bins [1]?
95% or more	N≤24	Average	HB/HA	No.
	N>24	Max of Average	HB/HA	No.
		Max of 90th percentile	720 operating hours	~~Yes.~~ No.
90% or more, but below 95%	N≤~~6~~ 8	Average	HB/HA	No.
	~~6<N≤24~~	Max of ~~Average~~	~~HB/HA~~	~~No.~~
		~~Max of 90th percentile~~	~~720 operating hours~~	~~Yes.~~
	N>~~24~~ 8	Max of Average	HB/HA	No.
		Max of ~~90th~~ 95th percentile	~~8760~~ 720 operating hours	~~Yes.~~ No.
Below 90%	N>0	~~Max of Average~~	~~HB/HA~~	~~No.~~
		~~Max of 90th percentile~~ Maximum [2].	~~8760~~ 720 operating hours	~~Yes.~~ No.

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

[1] For SO_2 CEMS, the bins were defined on sulfur content ranges.

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

(Note: EPA has requested that Table 2 be printed as shown below. Crossed out entries in this table represent items, originally in the proposed regulations, that were changed in the final version of the regulations.)

TABLE 2.—MISSING DATA PROCEDURE FOR NO_x and Flow CEMS

Trigger conditions		Calculation routines		
Annualized availability (percent)	Duration (N) of outage (hours)	Method	Lookback period	Bins [1]?
95% or more	N≤24	Average	~~HB/HA~~ 2160 operating hours	Yes.
	N>24	Max of Average	HB/HA	No.
		Max of 90th percentile	~~720~~ 2160 operating hours	Yes.
90% or more, but below 95%	N≤~~6~~ 8	Average	~~HB/HA~~ 2160 operating hours	~~No.~~ Yes.
	~~6~~ <N≤24	~~Max of Average~~	HB/HA	No.
		Max of ~~90th percentile~~	~~720 operating hours~~	~~Yes.~~ No.
	N>~~24~~ 8	Max of Average	HB/HA	Yes.
		Max of ~~90th~~ 95th percentile	~~8760~~ 2160 operating hours	~~No.~~ Yes.
Below 90%	N>0	~~Max of Average~~	~~HB/HA~~	No.
		Max of ~~90th percentile~~ Maximum.	~~8760~~ 2160 operating hours	Yes.

HB/HA=hour before and hour after the outage.
[1] For NO_x and Flow CEMS, the bins were defined on load ranges.

The major issues, raised by commenters and analyzed by EPA, were the following:

(1) Underlying Concepts

In general, commenters supported the basic underlying concept, on the one hand, of substituting an *interpolated* value derived from the average of the hour before and hour after when outages were short and annualized availability was above some threshold and, on the other hand, substituting a more conservative *historical* value when outages were longer or annualized availability dropped below some threshold. It should be noted, however, EPA does not agree with those commenters who seem to view interpolated values, like the average of the hour before and the hour after, as comparable to CEMS data. Interpolated values provide a satisfactory substitute for CEMS data only when outages are relatively short in duration and infrequent in occurrence. More extensive use of interpolated values increases the likelihood of incorrectly estimating emissions for individual monitors. To function effectively, the allowance trading component of the Acid Rain Program requires a complete and accurate accounting of emissions. It cannot rely on interpolated values for such an accounting. The EPA believes that high monitor availability, made possible by a missing data procedure that discourages outages, is the only effective guarantee that emissions will not be underestimated, as required by section 412(d) of the Clean Air Act.

(2) Trigger Conditions

(a) Annualized availability. A number of commenters expressed concern about the ability of CEMS to attain availabilities of 95 percent or more, particularly with monitors that would have to be retrofitted to meet the requirements of the Acid Rain Program. It was asserted that unsatisfactory results were experienced in Pennsylvania, where the average annualized availability for monitors retrofitted to meet the requirements of the State Implementation Plan was below 95 percent in the early phase of the program.

Response: A study of 186 retrofitted monitors during 1988–90 did not lend support to the commenters' concern. The study showed that approximately 75 percent of monitors at existing units, including units that will be covered under Phase I of the Acid Rain Program, have consistently attained availabilities above 95 percent. In addition, the most recent data on CEMS availability, obtained from the Commonwealth of Pennsylvania, indicates that, on average, annualized availability was 96 percent. This leads EPA to conclude that 95 percent availability is readily achievable, even by retrofitted monitors that are required to meet strict quality assurance and data validation standards in order to qualify as "available". It is also important to note that a monitor could be inoperative for a full 18 days each year and still have an annualized availability of more than 95 percent. The EPA believes that 18 days is more than enough time to accommodate both routine and unexpected outages for a properly maintained and operated CEMS.

Another commenter proposed indexing the top tier annualized availability trigger to the performance of the best monitors. It was argued that this would create an incentive for continuing improvement in monitor availability across the whole regulated community.

Response: While EPA encourages continuing improvement in availability, the agency believes the indexing approach might introduce an element of uncertainty into the emissions monitoring program that could be reflected, in turn, in the allowance market. The indexing approach would also present serious administrative difficulties both for EPA and sources. Therefore, EPA rejected this proposal.

Still another commenter argued that the bottom tier should be deleted and the second tier's trigger conditions and calculation routines should apply when annualized availability drops below 95 percent.

Response: EPA did not accept this proposal for several reasons. First, it would encourage the proliferation of short outages (6 hours or less, using the structure in the proposed missing data procedure), because values derived using the average of the hour before and the hour after an outage could be substituted for these short outages no matter how low the monitors annualized availability dropped. This would reduce confidence in the monitor's emissions accounting. Furthermore, the proposed change would remove virtually all incentives to repair a monitor with poor annualized availability. Accordingly, the Agency did not accept this commenter's proposal, instead preserving the

proposed separate lower tier, which is triggered by annualized availabilities below 90 percent and where conservative values are always substituted for missing data.

In summary, the final rule retains the three-tier structure of the earlier proposal, with the top tier still triggered by annualized availabilities 95 percent or better, and the bottom tier triggered by annualized availabilities below 90 percent.

(b) Duration of outages. Commenters made several proposals for modifying the length of outages that trigger various calculation routines. A number of commenters argued that the most conservative calculation routines should not be triggered by outages exceeding 24 hours but by outages exceeding 48 hours. The commenters maintained that a 48-hour trigger condition would provide a more reasonable length of time to repair monitors rendered inoperative by freak events beyond the operator's control.

Response: EPA rejected this proposal on three grounds. First, moving to a 48-hour trigger condition would remove an important incentive for quickly repairing monitors, even when the cause of the failure is easily fixed. Second, the commenters' proposal would mean that the calculation method based on averaging measurements taken the hour before and the hour after an outage would be used for outages as long as 48 hours. Using the hour before and the hour after approach on such long periods of missing data are likely to produce appreciable underestimations of emissions. Third, the argument for changing the trigger condition cutoff to 48 hours to allow more time for repairs was based on anecdotal evidence of repairs requiring more than 24 hours and did not convincingly demonstrate that 24 hours was insufficient for most repairs. The commenter's rationale could just as easily have been used for lengthening the cutoff to any duration longer than 24 hours.

Many commenters requested that the average hour-before/hour-after calculation procedure apply for outages longer than 6 hours when annualized availabilities ranged from 90 percent up to 95 percent (i.e., on the middle availability tier). Some proposed moving the trigger condition up to 8 hours; others proposed 12 and 24 hours. They argued that more repairs could be completed in 8, 12, or 24 hours than in 6.

Response: After weighing the possibility that extending the use of the average of the hour before and the hour after might reduce the incentive for quick repairs and increase the variability of substitution values produced by the missing data procedure, the agency has decided to adopt the proposal to extend the trigger condition from 6 to 8 hours in the final rule. The EPA believes that this change should allow more time for monitor repairs without significantly impairing the accuracy and consistency of emissions accounting. Along with this modification, only one trigger condition ($N>8$) will now apply to outages longer than 8 hours in the middle availability tier, whereas two trigger conditions ($6<N\leq24$ and $N>24$) applied to outages longer than 6 hours in the original proposed regulations. Together, these modifications simplify and support a truly graduated system of increasing incentives for improvements in annualized availability.

(3) Calculation Routines

(a) Calculation method. Commenters expressed strong views on the appropriate calculation method to employ in the missing data procedure. A diverse array of commenters argued that only by substituting the maximum previously recorded value could EPA effectively meet the requirement in section 412(d) of the Clean Air Act, stipulating that a unit should be considered as operating "in an uncontrolled manner" during periods when "the owner or operator cannot provide information, satisfactory to the Administrator, on emissions during that period." These commenters considered the maximum value as the only effective deterrent to deliberate shutdowns of CEMS during periods of high emissions.

Many commenters supported using a percentile of previously recorded values to calculate substitution values. Most thought the 90th percentile provided an adequate incentive for high CEMS availability without producing an undue overestimation of emissions and a concomitant inappropriate loss of allowances. Some proposed using the 70th percentile when annualized availability exceeded 90 percent.

The proposed rule requested comment on the advisability of using the average of the five highest previously recorded values as a calculation method. Almost all commenters rejected this proposal.

Response: EPA has incorporated into the revised missing data procedure calculation methods that it believes reflect a reasonable compromise of the extremes proposed by the commenters. The final rule contains a balanced, graduated approach with the substitution of progressively more conservative values for periods of missing data. Those monitors attaining the target annualized availability of 95 percent or better will substitute the 90th percentile value during outages exceeding 24 hours. Monitors whose annualized availability falls in the middle tier (from 90 percent up to 95 percent) will substitute the slightly higher 95th percentile value during outages exceeding 8 hours. Finally, monitors whose poor annualized availabilities place them on the third tier (below 90 percent annualized availability) will substitute the maximum recorded value for any outage. This should provide a substantial incentive to improve monitor availability. Combined with the use of uniform and shortened lookback periods, described below, this graduated approach will result in a more consistent incentive to maintain high operating availabilities than the proposed procedures.

(b) Lookback period. In the proposed rule, percentile calculations were performed on either 30 or 365 operating days of previously recorded data. Commenters objected to the 365-day lookback period, particularly for SO_2 concentration CEMS. They were concerned that a unit that reduced its SO_2 emissions could still be "stuck" with outdated high substitution values for a full year. This could prove particularly troublesome in the initial year of allowance accounting when substituted values might be derived from periods prior to the required implementation of SO_2 emissions reductions.

Response: The final rule drops the 365-day lookback period and adopts a 30-day lookback (i.e., 720 monitor operating hours) for all percentile and maximum value calculations employed in the missing data procedure for SO_2 CEMS. Moving to a single 30-day lookback addresses the commenters' concerns without reducing the incentive for increased monitor availability. One commenter noted and EPA's analysis indicates that the 90th percentile of 365 days of data did not yield consistently higher substitution values than the 90th percentile of 30 days of data. Shortening the lookback period from 365 to 30 days also substantially reduces data storage requirements for the missing data procedure.

On the same grounds, a single 90-day lookback (i.e., 2160 monitor operating hours) will be employed for NO_x and flow CEMS, instead of the 30- and 365-day lookback periods originally proposed. A 90-day lookback, rather than a 30-day lookback, is required for NO_x and flow, in order to increase the likelihood that appropriate load "bins" will contain at least some previously

recorded CEMS values. As explained below, "bins" are retained in the missing data procedure for NO_x and flow CEMS, but dropped for SO_2 CEMS.

(c) Bins. Many commenters objected to the expense of the proposed requirement for fuel sampling and analysis, which were needed in order to use SO_2 bins in the missing data procedure. Other commenters noted that it is inappropriate to mix coal sampling and CEMS data because coal sampling data are less precise and reliable. Data provided by one utility showed a daily variability of −10 percent to +45 percent in the difference between the SO_2 values derived from coal sampling and the SO_2 CEMS measurements.

Response: Based on this data, EPA agrees that it is inappropriate to compare coal sulfur content with CEMS values, either by correlation with contemporaneous CEMS readings or by direct substitution. Therefore, the final rule drops the fuel sulfur "bins" requirement from the missing data procedure for SO_2 CEMS. That is, SO_2 concentration will not need to be correlated with fuel sulfur content when performing percentile calculations of SO_2 substitution values. An added benefit of removing the fuel sulfur bin requirement is that the cost of implementing the missing data procedure for SO_2 CEMS will be reduced substantially, because utilities will not be required to perform coal sampling and analysis in order to implement the missing data procedure.

The Agency also considered dropping the load "bins" requirement from the missing data procedures for NO_x and flow CEMS. However, many commenters supported the use of load ranges when calculating substitution values for NO_x and flow, arguing that this would produce more accurate substitution values. Commenters who opposed the NO_x/load or flow/load correlations, embodied in "bins," cited either the unnecessary complexity of correlating operating data and monitor data, or the more accurate correlations that could be obtained using regression analysis.

Response: Using a uniform 90-day lookback in the missing data procedure for NO_x and flow CEMS and a smaller number of uniformly sized bins should reduce the complexity noted by some commenters. Although the regression analysis could provide satisfactory correlations, the method would require site-by-site analysis of extensive amounts of flow and load data. EPA believes that this approach would impose too great an administrative burden both on the industry and EPA. Thus, EPA has decided to retain the load bins for NO_x and flow CEMS and adopt a uniform 90-day lookback period in the NO_x and flow missing data procedures.

(4) Other Missing Data Issues

(a) Definition of missing data. The Agency reiterates that data from a certified backup monitor or an approved alternative monitoring system is not considered to be "missing." When such methods are operating in accordance with the regulations, data are considered to be "available," as required under section 412(d) of the Act. Correspondingly, when quality assured hourly data are not available from the certified CEMS or from one of these methods, then the missing data procedure must be used.

(b) Alternative missing data procedures. Several commenters requested that an administrative mechanism be established to allow sources to employ alternative missing data procedures in place of those specified in the regulations.

Response: The proposed regulations included provisions that would allow units with emissions controls that are independent of the combustion process (e.g., scrubbers) to use parametric substitution methods for missing data, instead of the standard missing data procedure. However, this "alternative" procedure is applicable only under clearly prescribed circumstances: it was designed to address anomalies that could result if the standard missing data procedure were applied to one specific class of units, those with independent emissions controls. In this case, the standard missing data procedure could seriously overestimate emissions. If the CEMS failed to report an hourly value but the emissions control equipment was functioning properly, the standard missing data procedure could substitute an inappropriately high uncontrolled emissions value, seriously overestimating emissions. The option of using a parametric substitution method at these units provides a greater level of consistency in emissions accounting between controlled and uncontrolled units.

The final rule includes distinct missing data procedures for oil- and gas-fired peaking units that qualify for exceptions to the SO_2 CEMS requirements, as described in Appendix D of the regulations. These procedures are adaptations of the standard missing data procedure, tailored to the specific characteristics of the excepted monitoring method.

EPA does not consider alternative missing data procedures to be justified for types of units other than those discussed above. The EPA is particularly concerned that a multiplicity of alternative missing data procedures could seriously jeopardize the national consistency of emissions accounting.

(c) Maximum controlled emission rate. Several commenters requested that EPA allow an affected unit equipped with add-on emission controls to substitute something more reasonable than the maximum recorded value, which may have occurred when the add-on emission controls were not functioning properly, if the owner or operator can show that the add-on emission controls were in fact operating properly during the current monitor outage.

Response: EPA agrees, and has modified the final rule to allow for a petition to the Administrator; specifically, if the owner or operator can demonstrate that (1) the affected unit's monitor data availability is below 90% availability and (2) the add-on emission controls were operating properly for the time period (or data gap) during which the affected unit experienced the monitor outage that would result in the substitution of an uncontrolled maximum value under the standard missing data procedures, then the owner or operator may submit the list of the average hourly values for the previous 720 quality-assured monitor operating hours, highlighting both the maximum recorded value and the value corresponding to the maximum controlled emission rate. The Administrator will automatically approve the use of the maximum controlled emission rate, if the petition adequately demonstrates that all of these requirements have been met.

G. Calibration Testing

Comments on the proposed calibration testing requirements for pollutant concentration monitors touched upon four major issues: terminology, the definition of instrument span, test specifications, and test procedures. Calibration issues related to flow monitors were discussed in the section on flow monitors above.

(1) Terminology

In the proposed rule the term "calibration error test" was used to refer to three separate calibration testing requirements, i.e., those required daily, quarterly, and at initial certification. The use of a single name created confusion because the purposes and procedures of the tests differed. The EPA received many comments that lack of clarity in the terminology caused uncertainty about the intent, timing, and

procedures of the tests. Commenters also noted that the proposed 7-day calibration error test at initial certification was really a hybrid of two tests: (1) A linearity check to ensure that CEMS responses were within tight tolerances of the calibration gases and that deviations remained relatively linear over the entire measurement range; and (2) a drift test to detect and limit day-to-day drift in the calibration curve of the monitoring instrument and to keep the instrument within range of high- and zero-level calibration gases. Commenters suggested that not only were the hybrid requirements confusing, but that using the tight standards of a linearity check in a calibration drift test could render the hybrid test needlessly difficult to pass without achieving the implicit goals of the calibration procedure. It was also noted that the linearity component of the hybrid test was equivalent to the proposed quarterly 3-point calibration error test and the drift test component was equivalent to the proposed daily calibration error test.

Response: In the final rule the calibration procedure performed at initial certification is disaggregated into its two component tests: a linearity check performed for one day only and a 7-day calibration error test. The term "daily calibration error" test has not been changed in the final rule.

The linearity check is a 3-point test in which the permissible deviation of the CEMS response from the calibration gases is defined as a percent of the "tag" value of the gases. The "tag" value is the vender certified concentration specified on the label of a cylinder of calibration gas. What was referred to as the "quarterly calibration error test" in the proposed rule is now called a "quarterly linearity check" to indicate that it is the same test as the linearity check performed at initial certification.

The daily calibration error test, specified in today's regulations, is a 2-point drift test, comparable to the calibration drift test required under NSPS (40 CFR 60, Appendix B) except that it requires using Protocol 1 calibration gases. Unlike the daily calibration error test in the proposed regulations, the permissible day-to-day drift in the CEMS measurements is now defined as a percent of the span of the instrument rather than as a percent of the calibration gas value. The 7-day calibration error test performed during certification is the same 2-point drift test as the daily calibration error test.

(2) Instrument Span

The proposed regulations stipulated that the CEMS span should be set to ensure that the average concentration would fall between 40 and 75 percent of the span of the instrument. Whenever the monthly average emissions concentration fell outside these boundaries, the operator was required to adjust the span to bring it back into compliance. The regulations also stated that "full-scale exceedances shall not occur."

A majority of commenters stated that the 40–75 percent span requirement would be too difficult to maintain and that the proposed monthly adjustments of span were not practical. They suggested that the boundaries on monthly concentration be expanded from 40–75 percent to 10–90 percent or that the span requirement be completely redefined to be compatible with definition of span under subpart Da of the New Source Performance Standards (NSPS).

Response: EPA continues to believe that the best way to define span for the purposes of the Acid Rain Program is to base it on boundaries that ensure that the predominant monitor readings fall in the middle third of the span, as was done in the proposed rule. However, in light of many negative comments and in order to make the calibration procedures under the Acid Rain Program as compatible as possible with current practices under subpart Da of NSPS, EPA has modified the span requirements in the final rule.

Under the final rule, every unit is required to set the span of its SO_2 and NO_x pollutant concentration CEMS at 125 percent of the "maximum *potential* concentration." For SO_2 CEMS, a unit's maximum potential concentration is determined by the specific characteristics of the fuel that the unit is capable of burning. In particular, the maximum potential concentration is calculated from the maximum percentage sulfur content and the gross calorific value of the fuel, using a conversion factor that assumes complete combustion (see Equation 1.2.1.a in Appendix A to part 75). The monitor range defined on the maximum potential concentration is known as the "high-scale" of the monitor.

For SO_2 CEMS on units with emission control equipment, the monitor must not only be capable of meeting the above requirements, it must also be able to perform and pass the calibration tests using low, mid, and high calibration gases whose concentrations are defined by the unit's "maximum *expected* concentration." For these units, the "maximum *expected* concentration" is the maximum concentration that would occur if the unit's control equipment is operating at its fractional design removal efficiency. It is calculated by multiplying the maximum potential concentration by one minus the design removal efficiency. The monitor range is set at 125 percent of the maximum expected concentration and is known as the "low-scale" of the monitor.

The operator of any unit may also elect to establish "maximum expected concentration" levels in order to determine additional sets of low, mid, and high SO_2 calibration gas concentrations to be used in calibrating on spans other than the one defined on the "maximum potential concentration." This option should accommodate situations, identified by commenters, where the most prevalent emission concentrations fall into one or more discrete bands, not necessarily in the center of the span range established using the maximum potential concentration. This rule allows sources, under such circumstances, to employ multi-span monitors, each span being calibrated on its own set of calibration gases.

As in NSPS, the span of NO_x and diluent gas CEMS is explicitly specified in the final rule: For boilers without emissions controls, the maximum potential concentration for NO_x pollutant concentration is assigned a value of 1,600 ppm at coal-fired units and 480 ppm at oil-fired and gas-fired units. For boilers with emissions controls, the maximum expected concentration is assigned a value of 800 ppm at coal-fired units and 400 ppm at oil-fired and gas-fired units. For other units electing to set a low-scale for their NO_x pollutant concentration monitor, the maximum expected concentration is assigned a value of 320 ppm at coal-fired units and 160 ppm at oil-fired and gas-fired units. The span of the diluent gas monitor would be set at 25 percent O_2 or CO_2, as applicable. Based on NSPS experience, this approach to defining the span of NO_x and diluent gas CEMS is effective without being either restrictive or burdensome.

Operators at all units are required to perform the quarterly and initial certification linearity checks on the high-scale of their instruments. In addition, operators of units with emission controls and other units that choose to use additional spans must also perform the quarterly and initial linearity checks on the low-scale of their instruments. Finally, operators need only perform the daily calibration error test on the monitor ranges that were actually used for one hour or more since the previous daily calibration error test.

This new approach for defining the span of CEMS responds to commenters' concern that the earlier 40–75 percent

approach in the proposed regulations would inevitably lead to violations of the stricture that "full-scale exceedances shall not occur." The EPA believes that under the new requirement full-scale exceedances should not occur. At the same time, the agency encourages operators to set the span of their instruments, where practicable, so that the majority of readings occur within 25–75 percent of the instrument span.

The modified approach to defining the span of CEMS closely resembles that used in NSPS, although it cannot exactly coincide due to differing program standards and emissions characteristics of the regulated units. Coordination of the definitions of span should reduce needless disparities in requirements on units affected by both NSPS and the Acid Rain Program. It should also facilitate implementation, since CEMS operators will find the new requirements to be familiar.

At the same time, the new approach addresses the commenters' two major concerns regarding the originally proposed method for defining span. It eliminates the uncertainty engendered by basing span adjustments on the previous month's average emissions concentration, and it prevents full-scale exceedances.

(3) Performance Specifications

The proposed rule required that pollutant concentration monitors be calibrated to within a performance specification of ±2.5 percent of the gas concentration when measuring calibration gases whose concentration was above 250 ppm and to within a performance specification of the greater of ±5.0 percent or ±8 ppm when measuring calibration gases whose concentration was 250 ppm or lower. For diluent gas monitors the specification was set at ±0.5 percent of the calibration gas. In all three calibration tests—daily, quarterly, and initial certification—the specification applied to the monitor's measurement of a reference Protocol 1 gas. On the daily and quarterly calibration tests, the monitor would be considered "out of control" if the percentage deviation of the monitor measurement from the "tag" value of the calibration was more than twice the performance specification. However, on the initial certification test, if the percentage deviation simply exceeded the performance specification, the monitor would fail and have to repeat the 7-day calibration error test.

A majority of commenters stated that it would be practically impossible to meet the specifications when using low-level concentration gases having concentrations between zero and 20 percent of the instrument span. Commenters suggested that the specification should not be applied to the "tag" value of the calibration gas, but to the full span of the instrument.

Response: EPA is making two substantive modifications of the proposed regulations to respond to the commenters' concerns. First, the definitions of the low- and mid-level concentration gases used in the linearity checks performed during initial certification and quarterly thereafter have been changed in the final rule. The low-level concentration is now designated as 20–30 percent of span instead of 0–20 percent of span; mid-level will be 50–60 percent, not 40–60 percent; and high-level will remain at 80–100 percent. Separate sets of calibration gases are determined separately for the high- and low-scale of the monitor, based on their respective span values. The revised concentration ranges are consistent with requirements under NSPS, which defines the concentration levels in this manner. As a result of these modifications and the change in the definition of the span of the instrument, the low-level gas, which was of greatest concern to commenters, is likely to be of higher concentration than it would have been under the proposed requirements. Therefore, monitors will more easily meet the linearity check performance specifications at the low calibration gas concentration. In addition, if the CEMS response is within ±5 percent of the calibration gas value, the specification will be considered to be met.

Second, in the daily calibration error test, the specification for the SO_2 and NO_x pollutant concentration monitors will be applied to the span of the instrument and not the "tag value" of the calibration gas, as had originally been proposed. At both the zero-level (0–20 percent) and high-level (80–100 percent) calibration gas, the pollutant concentration monitor's response will be required not to deviate from the calibration gas by more than twice the specification times the span of the instrument. For SO_2 and NO_x CEMS this means that the monitor and the calibration gas must not differ by more than 5 percent of the instrument span (either the high-scale or low-scale span, as applicable). For diluent gas, the monitor response and the calibration gas must not differ by not more than 1 percent CO_2 or O_2. In Pennsylvania, where similar standards have been in place, the failure rate on comparable daily calibration tests over several years has been below 1.5 percent.

Though EPA is making these changes in response to comments, the agency is concerned that basing the calibration specification on the span of the instrument may allow a large and potentially detrimental margin of error when calibrating on zero-level concentration gases. Therefore, the agency will continue to analyze the daily calibration error test data obtained under the Acid Rain Program and evaluate the effectiveness of the calibration error test.

In the linearity checks, both at initial certification and during the quarterly calibration audits, the performance specification will continue to be applied to the calibration gas value. This approach is necessary to ensure the accuracy of the monitoring program and is consistent with standard practice for linearity tests. Data from periodic cylinder gas audits performed under NSPS and under Pennsylvania's State Implementation Plan indicate that the required performance specifications for linearity checks are attainable.

(4) Test Procedures

(a) For initial certification. As part of the initial certification requirements, the proposed rule required the calibration error test to be performed once a day for seven consecutive days with the unit operating at 50 percent or more of maximum load. Each day, a three-point test, using low-, mid-, and high-level gases, was to be performed with the monitor being challenged 3 times at each concentration. Comments on this test requirement focused on three main issues: Many commenters felt the requirement to operate at 50 percent or more of maximum load was unnecessarily burdensome and could force some units to operate above their planned dispatch levels. Others objected to having to challenge the monitor three times at each gas concentration, saying that so much time would be spent on calibration that the monitor's ability to measure actual emissions would be impaired. Still others thought that a 7-day, 3-point test was redundant and unnecessary.

Response: In agreement with the commenters' concerns, the final rule drops the load stipulation for the calibration tests performed at initial certification. However, the unit is required to be operating during the period of testing, because calibration of the instrument is affected by temperature, pressure, and moisture conditions of the sampled gas as encountered under actual operating conditions. The final rule retains the requirement to challenge a monitor three times at each concentration level.

Under the final regulations a 3-point linearity check must be performed only for one day during certification. In this test three gas concentrations are needed to ensure linearity over the range of monitor measurements. The 7-day test is now a 2-point calibration error test. It is the same as the daily calibration error test that will be performed once the certified monitor begins operation.

The EPA believes that comprehensive and thorough calibration testing at certification is particularly important, because it will allow detection and correction of problems before the monitor becomes operational under the Acid Rain Program. Meticulous testing at certification can pay large rewards over the life of the monitoring program, enabling units to eliminate problems early that would have been much more costly and disruptive to correct later.

(b) Quarterly assessment. The proposed regulations required a three-point calibration error test to be performed each calendar quarter. Using low, mid, and high concentration gases, the monitor would be challenged three times at each concentration. Dual range monitors would perform a separate 3-point test at each range. Commenters expressed some confusion about the purpose and requirements of this test.

Response: The final rule retains the quarterly assessment essentially as originally proposed. As noted above, to help clarify the nature and purpose of the quarterly assessment, its name has been changed to "linearity check" instead of "three-point calibration error test." The quarterly test is intended to serve as a periodic "spot check" to ensure that CEMS measurements do not deviate from the "tag" value of each of the three calibration gases by more than ±5.0 percent. In addition, as a linearity check, it will ensure that deviations from the calibration gas values are relatively uniform over the full measurement range of the monitor.

(c) Daily assessments. The proposed rule required calibration error tests to be performed at least once every 24 hours using a low and high concentration reference gas. When performing this test, the operator was to make no adjustments for low-level concentration measurements before completing the high-level calibration checks. Commenters expressed concern that this requirement would prevent an operator from correcting the drift at the high-level gas (known as span drift) by the drift measured at the zero-level gas (known as zero drift). Another major concern focused on the ability of a CEMS to meet a performance specification based on the "tag value" of the low concentration gas.

Response: This test remains as proposed, except that the performance specification will be applied to the span of the instrument instead of to the reference gas values, as discussed in detail above under "Performance Specifications." This change should address the concern about the achievability of the performance specification. The final regulations retain the restrictions on adjustments for drift. However, the agency notes that an operator may computationally correct span drift for zero-drift, but only after both zero- and span-drift have been documented. This is comparable to the requirements under Performance Specification 2 (40 CFR part 60, Appendix B).

Exceptions to CEMS Requirement

EPA received more than 1,000 comments on proposed exceptions to monitoring requirements for SO_2, NO_x, and opacity, as well as on a general exception to the Acid Rain Program's emission reduction, permitting, and monitoring requirements for clean, small new units.

(1) For SO_2 CEMS

In the proposed regulations, exceptions from the CEMS requirements for SO_2 were proposed for two categories of units: Oil-fired units, in general, and combined gas/oil-fired units that derived 90 percent or more of their heat input during the year from natural gas. In the following discussion, the latter units will be referred to as "90-percent gas-fired units."

The first exception would allow oil-fired units to monitor their oil flow rate using a fuel flow meter, analyze the sulfur content of either continuous drip or "flow proportional" samples of the oil, and, then, calculate hourly SO_2 emissions from the corresponding hourly flow rate and sulfur content measurements. "Flow proportional" sampling refers to an automated process whose frequency of sampling is not tied to the time elapsed but rather is proportional to the amount of fluid passing the monitoring location. For example, samples might be taken every ten barrels or every 100 gallons or every 50 pounds of fluid. Under this proposed exception, hourly SO_2 emissions had to be reported within 24 hours of their occurrence.

The exception for 90 percent gas-fired units was similar. However, these units were required only to take daily manual grab samples of the oil, calculate daily SO_2 emissions, and report results within 24 hours. By implication, units burning natural gas exclusively were completely exempted from the SO_2 CEMS requirements.

Some commenters supported the proposed SO_2 monitoring exceptions; some recommended a longer turnaround time for oil analysis; and some proposed a less frequent sampling requirement for oil-fired units. One organization opposed less frequent oil sampling. Others supported allowing a fuel flow meter combined with a diluent monitor to be used in place of a volumetric flow monitor.

Response: The two exceptions included in the proposed regulations are retained in the final rule. In addition, based on the public comments that were received and an analysis of SO_2 emissions data in the National Utility Reference File (NURF) emission inventory, EPA is extending the exception for 90 percent gas fired units to all oil-fired units and lengthening the required turnaround time for oil sample analysis under this exception from 24 hours to thirty days. No other changes to the originally proposed exceptions from SO_2 monitoring have been made. In general, the exceptions granted to gas- and oil-fired units were based on substantial evidence showing that the excepted monitoring methods performed extremely well for these types of fuels with respect to the statutory criteria for equivalency to CEMS, as specified in section 412(a) of the Act. EPA believes that these exceptions are within its discretion in administering the Act. *See Alabama Power Co.* v. *Costle*, 636 F. 2d 323,360–61 (D.C. Cir. 1979). Details of EPA's position are given below.

(a) Exception for oil-fired units. As noted in the preceding paragraph, today's rule provides an exception in Appendix D of Part 75 for monitoring SO_2 emissions at oil-fired units based on the performance of the excepted monitoring methods. The first excepted method relies on automatic fuel sampling, whose sampling frequency is proportional to the fuel flow, with a minimum of one sample drawn each hour. In addition, the "continuous" and flow-proportional oil samples are required to be aggregated and analyzed for sulfur content on a daily basis, using American Society for Testing and Materials (ASTM) standard laboratory procedures. Finally, the rule requires that oil flow meters be calibrated annually.

Since SO_2 emissions from this class of unit can be significant, the rules have designed the method to ensure accurate information, representative of each hour of unit operation, thus ensuring equivalence to CEMS. The method has three main features: accurate metering

of oil flow, as-fired oil sampling (i.e., actual fuel samples taken in proportion to fuel consumption as measured by the fuel flow meters), and accurate accepted procedures specified by ASTM for analyzing the sulfur content and density of the oil samples.

As is explained further below, the evidence available indicates that the oil sampling and analysis method compares favorably to the statutory criteria for "sameness" in section 412(a) of the Act: (1) It is as precise as CEMS; (2) it is no less reliable than CEMS; (3) the information generated from the method—calculations of actual hourly emissions based on representative samples and measurements—is as accessible and useful as that reported by CEMS; and (4) it compares acceptably to the CEMS requirements with regard to the timeliness of measurements and data verification. In short, the only relevant distinction between the CEMS requirements and the flow-proportion continuous oil sampling and analysis method approved today is the measurement method.

The following is an elaboration of EPA's response to two aspects of this exception that attracted specific public comments:

(i) Accuracy of fuel-flow metering. The final rule preserves the proposed fuel flow meter accuracy specification of ±2 percent. The EPA clarifies that this specification is ±2 percent of the maximum flow that can be measured by the meter, known as the "upper range value". Several commenters asked that EPA set a more relaxed accuracy limit. This proposal may have been prompted by confusion over whether the accuracy specification was to be applied to the actual flow or the upper range value. The EPA evaluated this request and decided not to alter the accuracy requirement, based on two considerations: First, information available to EPA indicates that the ±2 percent accuracy specification is achievable by commonly-used types of flow meters, including coriolis-type mass flow meters, positive displacement flow meters, and square-orifice differential-pressure flow meters, and some other less expensive flow meters. Second, the ±2 percent accuracy limit is necessary given the variations in accuracy inherent in the ASTM fuel sample analysis methods. Maintaining the ±2 percent accuracy limit is particularly important, because the final rule adds flexibility by allowing the use of numerous applicable ASTM analytical methods.

(ii) As-fired oil sampling. The CEMS requirements call for continuous measurements of emissions (i.e., hourly averages based on measurements taken at fifteen minute intervals with no fewer than 2 measurements in any hour) followed by data verification within 24 hours. The excepted method for oil-fired units requires automatic sampling on an hourly (or more frequent) basis in proportion to the rate of oil flow. In the oil fuel sampling and analysis method, fuel sample grabs are taken in proportion to the fuel used, with sample grabs required at least once each hour, and sample analyses required each day. This provides samples that are truly representative of each hour of unit operation. Thus, both methods result in measured hourly values.

Commenters suggested a number of ways that the frequency of oil sampling could be reduced, including procedures that account for changes in the sulfur content upon the arrival of each new oil delivery. EPA rejected these suggestions because they would have resulted in less frequent sampling, which would have increased the potential to underestimate the sulfur content of the oil combusted by this category of unit, and would not have assured that the reported emissions represented the actual emissions for the reported point in time.

(b) Exception for oil-fired and gas-fired units. The final rule retains the previously proposed excepted method for calculating SO_2 emissions at gas-fired units that burn natural gas for no less than 90 percent of their total heat input during the year and burn oil—including diesel oil—as their backup fuel for the remaining heat input. *See* 56 FR at 63089. In addition, as noted above, the final rule extends this exception as an option to oil-fired units. These units are not required to use this excepted method for SO_2 monitoring. Rather, they may install a CEMS or employ the continuous oil fuel sampling method described above and in appendix D of part 75.

(i) De minimis exemption from SO_2 monitoring when units burn 100 percent natural gas. Gas-fired units would only be required to monitor SO_2, when they are actually burning oil. This is appropriate due to the *de minimis* nature of the SO_2 emissions from refined natural gas fuel. See discussion of *de minimis* exceptions in the preamble to part 72, Permits. Specifically, units that exclusively use natural gas emit only a small amount of SO_2 each year. Based on the typical amount of sulfur found in natural gas, as measured by ASTM analysis methods, a typical exclusively gas-fired unit emits less than 100 kg of SO_2 annually while combusting natural gas. See discussion of *de minimis* exceptions in the preamble to part 72, Permits.

While emissions are also relatively small from gas-fired units that use oil, including diesel, as a back-up fuel for no more than 10 percent of their heat input, the emissions are not completely negligible. According to the National Allowances Database, there are 525 existing 90-percent gas-fired units. This category of unit emitted 7,600 tons of SO_2 in 1985, yielding per unit average emissions of less than 15 tons annually. Six of the 525 units emitted more than 100 tons in 1985, the cut-off under title V of the Act for "major" sources. Thus, the final regulations stipulate that when a 90-percent gas-fired unit combusts oil, it is required to use an in-line oil flow meter to continuously monitor the amount of oil consumed and to use the highest sulfur value from a series of daily fuel samples in calculating the SO_2 mass emissions in units of pounds per hour.

(ii) Comparison of the excepted method to CEMS. As with the excepted continuous fuel sampling method, this exception for 90 percent gas-fired and oil-fired units compares well to CEMS with regard to precision, reliability, and accessibility. The method differs from the flow-proportional "continuous" oil fuel sampling method—and thus from CEMS—only with regard to the measurement method. As was discussed above, the CEMS and the flow-proportional continuous oil fuel sampling method call for continuous measurements of emissions. In contrast, the alternate excepted method for 90 percent gas-fired and oil-fired units requires daily manual oil samples. Furthermore, SO_2 emissions are required to be calculated using the highest measured fuel sulfur content recorded in the previous 30 daily samples.

EPA believes that differences between this method and CEMS with regard to measurement and verification frequency are not critical to the exception's methodology. Specifically, as discussed in greater detail below, the measurement frequency, applicable to CEMS, is not needed in the case of gas-fired units and oil-fired units in order to generate representative calculations of a unit's actual SO_2 emissions on an hour by hour basis.

Measurement frequency. EPA considered several factors in concluding that the specified measurement frequency is sufficiently timely for gas-fired units and oil-fired units. First, due to the homogeneity of this particular fuel source, the sulfur content of the daily oil-fuel supply used by these categories of units is unlikely to vary

significantly during a day. Oil fuel typically has a highly homogeneous sulfur content as compared to coal and coal-derived fuels. Moreover, even day-to-day variation in sulfur content will be very limited, since the two source categories which will use this method typically purchase and consume batches of oil fuel infrequently. In addition, fuel usage at gas- and oil-fired units can be measured accurately, and virtually instantaneously, using a flow meter.

Finally, the approved daily sampling method requires that SO_2 emissions be calculated using the highest measured sulfur content of the previous 30 daily samples. This prevents any possible underestimation in the unlikely event that a daily sample had a lower sulfur content than the average for the entire day. It is, thus, highly improbable that any emissions would not be accounted for using this method.

Verification frequency. Although the "timeliness" criterion in section 412(a) of the Act does not unequivocally mandate exactly the same turn-around time in measurement verifications for CEMS and excepted methods that involve collection of actual measurement samples, EPA believes that the verification frequency for any monitoring method should be as short as is practical. This is important in order to provide up-to-date emissions information to the allowance market and to meet regulatory deadlines for quarterly emissions reports and the end-of-year allowance/emissions reconciliation. Nevertheless, as numerous commenters pointed out, a "next day" turn-around requirement would be particularly impractical for units covered by this exception. They are frequently located in remote areas and, due to their size and the infrequency of their burning oil, they typically must send their oil samples to outside commercial laboratories for analysis. Many commenters suggested that seven days would be the minimum reasonable amount of time to send out oil samples for analysis and receive results while others suggested a 15 or 30 day turnaround. Concern was expressed that it would be administratively impractical to conduct a 24 or even 7 day turnaround thus making this option unattractive to most, if not all, of the oil fired units for which this option is intended. As proposed, those selecting this option would be driven to inefficiently analyzing single or small batch samples. Concern was also expressed that this approach could inadvertently encourage the development of on-site, less accurate, lab analysis. Thus, EPA does not consider a seven day turnaround practical for small or remotely located units. Further, in situations where the information is needed more quickly for end of year true-up or enforcement purposes, the sample(s) could be analyzed more quickly on a case by case, as needed, basis. Thus, EPA has decided to promulgate a 30 day turnaround period.

(iii) Other considerations. EPA's analysis also indicates that this exception represents an appropriate way to reduce the particularly disproportionate financial burden that requiring SO_2 CEMS would impose on oil-fired units. Total emissions from all oil-fired units represent approximately 4 percent of the SO_2 emissions from all affected units. Nevertheless, monitoring costs under the Acid Rain Program for small oil-fired units can range as high as $490–$49,000 per ton of SO_2 emitted. The proposed exception will provide a viable, more cost effective option for such sources.

Another concern, raised by commenters, was that units qualifying for this exception might subsequently change their proportion of oil usage, thereby increasing the level of emissions not being monitored by CEMS. To address this concern, the definition of "gas-fired" has been revised in the final rule to include a cap on the amount of oil that qualifying units could use in any one-year or 3-year period. Further, by extending the option to all oil-fired units, the decision to install an SO_2 CEM system will not be capacity factor driven. The result is a simplified set of requirements that provide additional operational flexibility to units that experience atypical increases in utilization in any given year.

(c) Other suggested methods for calculating SO_2 emissions considered. Commenters proposed several other methods for determining SO_2 emissions. EPA rejected these approaches because they represented clear departures from the statutory criteria for evaluating alternative monitoring methods and because of concerns about their administration and enforceability.

Permit limit proxy. One proposal for oil-fired units was to always use the "maximum permitted" oil sulfur content as a default sulfur value for units with such permit limitations. The EPA rejected the proposal because a fuel's permitted sulfur content bears no relationship to physical measurement and verification procedures, based on actual operations, that are implicit in the word "monitoring," as mandated in the Act.

"F-factor"/fuel flow method. Other commenters proposed allowing a diluent monitor, an "F-factor," and a fuel flow meter to be used as an alternative to a CEMS volumetric flow monitor. (An "F-factor" is a fuel-specific constant that relates the heat content of a fuel and the amount of gases given off upon combustion. It is used to convert diluent gas concentration and pollutant concentration into a value of pounds of pollutant per million British thermal units of heat input.) In a four-day experiment performed by one commenter, the method appears to have produced measurements that track those generated by a combined SO_2, CEMS and volumetric flow monitor. However, EPA does not believe that four consecutive days of data are sufficient to support a conclusive equivalency determination at this time. To be approved, this method would have to meet the criteria for alternative methods in a thirty-day trial as required by the provisions of § 75.40 of the rule. If approved, this alternative method would be promulgated as an excepted monitoring method in appendix I and would apply categorically to oil-fired and gas-fired boilers.

Coal fuel sampling: EPA also considered coal fuel sampling as a method of monitoring SO_2 emissions. As with other methods suggested, EPA evaluated the method's ability to obtain accurate and representative samples and evaluated the practicality of using the method to obtain samples, determine the amount of fuel used, and calculate emissions for any given hour. Whereas flow-proportional continuous oil fuel sampling yields extremely accurate information on which to base actual emissions calculations, such accuracy cannot be consistently achieved by coal fuel sampling. Oil fuels have highly homogeneous sulfur content as compared to coal and coal-derived fuels. Comparisons of oil fuel sampling to CEMS have shown variations in contemporaneous readings of 0 to ±5 percent on an hourly basis. Similar comparisons of coal sampling to CEMS have shown variations in contemporaneous readings ranging from ±10 to ±45 percent on a daily basis, with significantly greater variations on an hourly basis.

These results are not unexpected since the physical composition of coal makes it extremely difficult to specify and use a standardized process for taking representative fuel samples. Because coal characteristically can contain large, but irregular, concentrations of impurities, the sulfur content of coal can vary greatly within a single shipment. Consequently, two adjoining chunks of coal may differ dramatically from each other. EPA does not consider that units performing coal

fuel sampling and analysis qualify for an exception to the CEMS monitoring requirements for SO_2.

(2) For NO_x CEMS

The proposed regulations included no exceptions to the NO_x CEMS requirements.

Through the public comment process, EPA received numerous proposals for exemptions from the NO_x monitoring requirements. The comments focused primarily on the category of affected units that are not coal-fired and are not, therefore subject to NO_x emission limitations under section 407 of the Acid Rain Program. Some commenters asked that such units be exempt from the title IV NO_x emissions monitoring obligations in their entirety. Others recommended an alternative method for infrequently operated (i.e., "peaking") units, such as diesel- and dual-fuel reciprocating internal combustion engine units, combustion turbines, and other oil- and gas-fired units with a capacity factor below some stipulated level.

Response: EPA disagrees with those proposing a total exemption from NO_x monitoring requirements for units that do not have a NO_x emission reduction obligation under section 407 of the Act. Section 412 of the Act clearly requires *all* units with emissions limitations under title IV, not just those with NO_x limitations, to monitor NO_x emissions. This information is important to Acid Rain Program implementation, particularly with regard to the various studies and reports mandated by the Act, which specifically identifies NO_x as a key acidic deposition precursor pollutant.

EPA agrees, however, that it is appropriate to craft a limited exception to the NO_x CEMS requirements, applicable only to gas- and oil-fired "peaking" units having a capacity of 10 percent or less over the previous three years. See discussion of *de minimis* exceptions in the preamble to part 72, Permits. These two categories of peaking units have extremely low emissions both collectively and individually. Total NO_x emissions from this category of unit is estimated at 40,000 tons per year. At the same time, the cost of monitoring NO_x emissions using CEMS could be several hundred dollars per ton of NO_x monitored. In addition, a large number of sources that fall into these two categories are located in small municipalities, where the cost of installing, operating, and maintaining CEMS would be particularly burdensome.

EPA believes that these considerations, and the fact that these categories of units are not subject to NO_x emission reduction requirements under title IV, are pertinent. The EPA believes that exceptions to monitoring requirements are appropriate to consider in cases where insignificant annual emissions are involved and the statutory objectives can be met. Specifically, the primary concern underlying the statutory emphasis on CEMS as the mandated monitoring method is the need for precise, reliable and timely information indicating the exact emissions of each unit *in order to determine whether a source or unit has met its emissions limitations.* (emphasis added). S. Rep. No. 427, 101st Cong., 1st Sess. 336–337 (1989). In short, given the absence of a compliance obligation for these two categories of units, and the high costs of installing and operating CEMS at the units, a reliable exception method would seem justified.

(a) Approved method. The final regulations allow gas- and oil-fired "peaking" units to account for their NO_x emissions using site-specific NO_x emission factor correlations at various unit loads. The term "peaking unit" is typically used by industry to describe a unit that is operated at a capacity factor of 10 percent or less. See, for example, the Electrical Power Research Institute's *Technical Assessment Guidelines* (1991), which classifies units on the basis of load. The term "capacity factor" refers to the ratio of the unit's actual electrical or steam output (in MWehr) to the output if the unit ran continuously for 8760 hours a year at the unit's rated nameplate capacity. A capacity factor of 10 percent would be typical of a unit that operates 400 hours a year. A "low capacity factor" unit typically refers to a unit that is operated at a capacity factor of 30 percent or less. The term encompasses both "intermediate load" and "peaking" units. A "high capacity factor" or "base loaded" unit refers to units operated at a capacity factor of 50 to 70 percent.

Any unit using this method will be required to develop a historical record of NO_x emissions at various loads to establish the correlations. The site-specific derivation of correlations, based on historical emissions data, is necessary, because NO_x formation is uniquely dependent on the particular operating characteristics and equipment used at a unit. Once the correlations are derived, they are applied to the unit's actual load data in order to calculate the unit's NO_x emissions for the year. In addition, periodic NO_x emissions stack testing is required to verify the continued representativeness of the correlations. The EPA believes these procedures will ensure that the correlations produce sufficiently representative data on actual emissions for this limited class of units. This approach is consistent with the recommendations of many of the commenters who identified the need for an exception to NO_x CEMS for gas- and oil-fired peaking units.

It is important to note that the approved emissions/load exception does not meet the criteria for an alternative monitoring system, as specified in section 412(a) of the Act. As such, it is only approved for use in a very limited class of units. To date, no continuous alternative NO_x monitoring system has been field tested alongside a certified NO_x CEMS and shown to meet the equivalency criteria specified in the Act. Thus, there is no exception to NO_x CEMS requirements beyond the exception for oil- and gas-fired "peaking" units.

Some commenters expressed concern that a unit, once qualified for an exception to the NO_x CEMS requirement, could then change from a low capacity factor to a high capacity factor unit, or change its fuel usage and thereby undermine the representativeness of the emissions/load correlations. To prevent this, the final rule includes a definition for "peaking unit" that links the continued availability of the NO_x monitoring exception to a unit's mode of operation during the previous three years. It provides additional operational flexibility in the case of atypical end-of-year increased utilization, while setting limits on a source's ability to qualify for an exception to the NO_x CEMS requirements. The regulations also include procedures for determining if units with fewer than three years of operating experience qualify as peaking units. If a unit's utilization changes so that it is no longer a "peaking" unit, it would become subject to the CEMS monitoring requirements in the following calendar year. Similarly, if a unit changes its fuel usage and thereby changes its emission characteristics, the owner or operator would be required to revise the unit's correlations or install a CEMS for NO_x by the end of the following calendar year.

(b) Other methods considered for NO_x exceptions: AP–42. A number of commenters promoted an approach, similar to the emissions/load correlation approach approved today, but based on the EPA-developed emission estimation factor known as AP–42. Despite superficial similarities, that approach would rely on emission factors derived from industry-wide average (i.e., generic) estimates of emissions for different fuel and boiler types. The EPA

rejects such an approach, because its estimates are not based on the actual historical operating experience of the units to which the estimates would be applied. Generic estimation would be especially detrimental in calculating NO_x emissions, because of wide variations in emissions formation characteristics from unit to unit.

The unit-specific NO_x emissions/load correlation approach approved today provides a more representative calculation of the actual emissions at a particular unit than the generic AP–42 emission estimation factors. This is especially true for combustion turbines and diesel and dual-fuel reciprocating internal combustion engines, which tend to have relatively steady and predictable NO_x emissions.

(c) Other capacity factor cut-offs. As discussed above, the exception to the NO_x CEMS requirement applies to "peaking units," defined as units with a capacity factor of 10 percent or less over the previous three years and 20 percent or less in each of those years. The EPA received proposals for NO_x CEMS exceptions based on other capacity factor cut-offs. Some commenters suggested that oil- and/or gas-fired units with a capacity factor of 30 percent or less should be able to determine NO_x emissions by an excepted method. The EPA has rejected this suggestion since it considers the NO_x emissions from existing units operating at a capacity factor between the approved 10 percent cut-off and the proposed 30 percent cut-off to be not *de minimis*, either individually or as a group. Such units can emit more NO_x than many coal-fired units affected in Phase I of the program. According to the NURF database, the entire category of 30 percent or less, gas- and oil-fired units emitted approximately 400,000 tons of NO_x in 1985.

(3) For Opacity Monitoring

The proposed rule contained two classes of exemptions to the part 75 requirement that affected units install continuous opacity monitors. Gas-fired units that derived no less than 90 percent of their total annual heat input from natural gas were exempt as were wet scrubbed units. These and all other affected units would still be required to meet any other applicable federal, state, and local opacity monitoring requirements.

Some commenters suggested that the opacity monitoring requirements under the Acid Rain Program should not go beyond other existing federal, state, and local requirements.

Response: EPA cannot adopt this proposal, since section 412 of the Clean Air Act Amendments requires the installation of continuous opacity monitors at all affected units. There appear to be a substantial number of affected units combusting residual oil which exhibit significant opacity levels, yet are not subject to opacity monitoring requirements in every state. The opacity data, obtained under part 75 of these regulations, is to be sent to state and local air control agencies.

However, the Agency is using its discretionary authority to provide class exemptions for units that do not have significant opacity levels and for units that may not be able to provide meaningful opacity information. Thus, in the interest of meshing the Acid Rain Program opacity monitoring requirements with those of pre-existing federal, State, and local air quality programs, the final rule exempts gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the previous three calendar years and diesel and dual-fuel reciprocating internal combustion engine units. As noted in the preamble to the proposed rule, gas-fired units have very low opacity levels, and extremely few of them (less than 5 percent of the 90-percent gas-fired units in the National Allowances Database) are required to monitor for opacity under other federal, State, or local regulations. Likewise, states such as Indiana, Iowa, and Kansas with many diesel and dual-fuel reciprocating internal combustion engines do not require the monitoring of opacity because of low opacity levels (e.g. below 10 percent opacity, even during startup). Nevertheless, where such requirements exist, this exception for title IV purposes has no effect on a unit's obligation to comply with other provisions of the Act. *See Alabama Power Co.* v. *Costle*, 636 F. 2d 323, 360–61 (D.C. Cir. 1979).

One commenter remarked that many wet scrubbed units successfully monitor for opacity under state programs and suggested that it would be appropriate for EPA to require opacity monitors on wet scrubbed units.

Response: EPA acknowledges that it is sometimes possible to monitor opacity in the stack or at the inlet of wet scrubbed units, depending on site-specific conditions such as the temperature of the flue gas. Therefore, under the final rule, only wet scrubbed units where condensed water is present are exempted from opacity monitoring for acid rain purposes. Nevertheless, if the State, local, and other federal programs require monitoring of opacity, then compliance with those regulations is still required.

Another commenter expressed concern that the opacity monitoring requirements might be avoided by units whose classification changes from "gas-fired" to "oil-fired," due to their using a higher proportion of oil for their heat input.

Response: The Agency has revised its definition of a "gas-fired" unit to allow units to use a three year period in calculating the proportion of their heat input derived from natural gas. This will reduce the likelihood of a unit's being accidentally reclassified without significantly changing the characteristics of its emissions. However, if a unit should still exceed the specified proportion of oil in its fuel blend and thereby change its emission characteristics, the owner or operator is required to install and certify a continuous opacity monitor within 365 days of the occurrence of the change in classification.

(4) For Clean, Small New Units

In the proposed rule, EPA requested comment on whether exceptions to some or all of the Acid Rain Program requirements should be extended to small new units, based on the relative insignificance of their total emissions. Existing units of less than 25MWe capacity are exempt from the title IV by virtue of the statutory definition for "existing unit," but there is no explicit exemption for small new units. Specifically, EPA asked whether small generators that only incidentally supply power to the grid should be subject to the full range of Acid Rain Program requirements. The overwhelming majority of those who commented on the issue believed that some form of relief would be appropriate for small new units with low emissions. Various demarcations were suggested by the commenters for defining the categories of units that would qualify for such an exception. They include: A size cutoff in MWe, with commenters suggesting sizes ranging from 5 to 25 MWe; a tonnage emissions cutoff such as that used in EPA's Prevention of Significant Deterioration air pollution control programs; and exceptions based on boiler or engine type. Two related concerns, particularly noted by the commenters, were the relatively high, per-unit cost of monitoring extremely small sources (i.e., those emitting in the range of one-ton of SO_2 per year), and the unusual burden these costs would impose on small generators and small communities. Commenters also drew attention to the heavy burden, both to sources and to EPA, that would result from having to issue acid rain permits to all such units.

Response: As is discussed more fully in the preamble to part 72, the Agency agrees with the commenters that a conditional *de minimis* exception to the emissions reduction, permitting, and monitoring requirements of the Acid Rain Program is appropriate for small, new, "clean" units. Specifically, units having a nameplate capacity of 25 MWe or less and combusting fuels with a sulfur content not greater than .05 percent by weight would be conditionally excepted from all Acid Rain Program emission reduction, permitting and monitoring requirements, subject to a continuing requirement to certify their eligibility for this exception. EPA's analysis indicates that the sulfur content standard of this exception would be met by units combusting natural gas and by units combusting diesel fuel refined to meet requirements in the Clean Air Act Amendments for on-road vehicles. Those units that do not meet the nameplate capacity and fuel sulfur content criteria will be required to meet all title IV Acid Rain Program requirements. Moreover, EPA will reconsider the exception if significant increases in emissions from this category are found to occur in the future. EPA believes that this exception, and the safeguards associated with it, are in keeping with the Administrator's authority to grant *de minimis* exceptions.

VI. Discussion of Changes to Part 77—Excess Emissions

Part 77 sets forth the requirements for units that have sulfur dioxide or nitrogen oxide emissions in excess of their emissions limitations. Units with excess emissions of sulfur dioxide must submit offset plans providing for the deduction of allowances equal to the tonnage of excess emissions and must pay $2,000 (as adjusted by the Consumer Price Index) per ton of excess emissions. Units with excess emissions of nitrogen oxides also must pay a $2,000 per ton penalty. In addition, interest is owed for late penalty payments.

A. Restructuring Changes

In response to general comments encouraging streamlining of the rules, portions of part 77 have been reorganized and simplified. First, like all the definitions of terms in other parts of the rule, definitions from part 77 have been consolidated in § 72.2. Further, provisions that were redundant with generally applicable provisions in part 72 were deleted. These include applicability, federal and state authority, signatory requirements, and recordkeeping. The substance of these provisions (including the reservation of federal authority) was not altered by this organizational change. Finally, Appendix A was deleted. It duplicated certain provisions already in the rule and provided information, showing the calculation of the excess emission penalty, that is more appropriately left for guidance materials.

B. Response to Comment

(1) Offset Plans for Excess Emissions of Sulfur Dioxide

Section 77.2 of the proposed rule required that each offset plan contain specific, detailed information about every unit with excess emissions. For example, the proposed rule required that the plan explain how and why excess emissions occurred at the unit, what corrective actions had been taken, and the schedule and increments of progress for offsetting the emissions in the future. A unit wishing to use a new compliance option to obtain allowances for offsetting had to include the planning requirements for that option in the offset plan.

The Agency received numerous comments on this section of the rule. In general, the commenters thought the offset planning process was unnecessarily lengthy, burdensome, and complicated. Moreover, they strongly supported eliminating most of the offset information and scheduling requirements, especially for cases where an offset plan simply calls for deduction of allowances from the excess emitting unit's account in the year after the excess emissions occurred. In addition, a few commenters questioned the Agency's authority to impose certain information requirements.

Response: Section 411 of the Act requires the owners and operators of a unit with excess emissions to submit "a proposed plan to achieve the required offsets," which plan the Administrator will approve "as submitted, modified, or conditioned." This provision gives EPA the discretion to require information deemed necessary to review offset plans and to determine what conditions to require. Further, Congress intended that offset plans could be broader than simply a statement of when allowances would be deducted. See 136 Cong. Rec. S16969, 16982, daily ed., October 27, 1990 (stating that the offset plan should show how source will reduce its emissions to achieve the requirements of title IV, including a plan to achieve required offsets). Nevertheless, in light of the comments supporting an easing of the regulatory burden, the Agency has reconsidered its approach for carrying out section 411 and has simplified the requirements for offset plans.

Information requirements have been tailored to fit the type of offset plan that is submitted and the compliance status of the unit involved. In general, if a plan specifies an immediate deduction of allowances to offset excess emissions, no additional information is required. Only if the unit has had excess emissions for two years in a row must the plan include information on how the excess emissions occurred and what measures are being taken to prevent excess emissions in the future. If a plan specifies a deduction of allowances at a date after the year following the year in which excess emissions occurred, the plan must in addition demonstrate that deducting the allowances earlier would interfere with electric reliability. However, compliance options are no longer tied to offset plans and are submitted separately as permit revisions.

There are several reasons for these changes. First, the Agency believes that by simplifying the proposed rule, it can ease the regulatory burden on sources and on the Agency without any adverse environmental impact. The Agency believes that in most cases an offset plan that simply requires immediate surrender of allowances to offset excess emissions will be sufficient. Such a plan, coupled with the automatic penalty of $2,000 per ton of excess emissions and the enforcement remedies under other sections of the Act, provides a strong incentive for owners and operators to be in compliance. However, a more detailed plan, including compliance schedules, may be needed in unusual cases, e.g., to ensure immediate and appropriate steps are taken to bring a unit with recurring and egregious violations back into compliance. The Agency believes that, in cases of repeated excess emissions, information on the cause of the excess emissions and measures to prevent future excess emissions will assist in determining whether a more detailed offset plan is necessary. The Agency has reserved the authority to require detailed schedules of compliance on a case-by-case basis and intends to use this authority only in extraordinary cases.

Second, even though some of the upfront information requirements have been deleted, the Agency's ability to obtain information about the unit has not been compromised. The Administrator still retains the discretion to ask for supplemental information under this part and also has the broad

authority to demand information under sections 114 and 307 of the Act.

Finally, while a compliance option (such as substitution or reduced utilization) may no longer be approved as part of the offset plan, units retain the flexibility that they had, under the proposal, to use compliance options to accomplish the offsets. Under the final rule, a unit may still use the permit revision procedures in part 72 to obtain approval for a compliance option. Depending on whether the unit obtains approval for an offset plan with delayed deductions of offset allowances, newly available allowances under an approved compliance option can be used directly to make offsets or to replenish the unit's account after offset allowances have already been deducted. Under this approach, a compliance option is approved under the same procedures in part 72 regardless of whether the unit involved had excess emissions in the prior year. Of course, the choice of a compliance option will not alter or stay the requirements of the offset plan.

(2) Administrator's Action on Proposed Offset Plans

The proposed rule required each proposed offset plan, regardless of how simple or complex it was, to undergo the same approval process. This process included a public notice and public comment period and was to be completed within six months of the proposed offset plan's submission. Several commenters questioned the Agency's authority to provide public notice and comment and recommended shortening the approval process for at least the simplest kinds of offset plans. The six-month approval process was viewed as serving only to delay expeditious compliance with the offset requirements.

Response: The Agency believes that it has the same authority to provide for notice and comment for an offset plan, which conditions a permit, as it has with regard to the permit itself. Nonetheless, in light of these comments and the simplified approach the Agency has taken to offset planning, the Agency has decided to shorten the process for approving most offset plans.

Accordingly, the Agency has divided offset plans into two categories: Those that specify deducting allowances immediately and those that specify deducting allowances at a later date. In the latter case, the offset plan will still go through the up-to-six-month approval process described in § 77.4 of the final rule. This is essentially the same process that was laid out in the proposal. When a unit wants allowances deducted later in the year or in a subsequent year, the public should have the opportunity to comment, e.g., on why allowances are not being immediately deducted or whether a more detailed plan is appropriate.

The Agency will generally deal with the first category of offset plans in a much simpler way. If a proposed offset plan specifies deducting allowances immediately and the allowances are in the unit's account, the plan may be approved without further review as an automatic amendment to the permit. The Agency believes that, in general, a public notice and comment period in such a case would serve no purpose. In requiring the soonest possible deduction of allowances, the offset plan already meets the requirement, under section 411(b) of the Act, that allowances be deducted from those allocated for the source. Notice and comment would only delay the offsetting of emissions that would otherwise occur soon after submission of the proposed offset plan. However, in those exceptional cases where, despite the submission of a plan calling for immediate deductions, the Agency determines that a more detailed offset plan with compliance schedules is necessary, the public should have an opportunity to comment on the schedules. Therefore, the six-month approval process will apply.

(3) Interest on Penalties for Excess Emissions

The proposal required the owners and operators to pay interest on the automatic $2,000 penalty for each ton of excess emissions if the penalty payment was late. The Agency received numerous comments concerning the interest requirement. In general, commenters questioned whether the Agency had the authority to collect interest on the penalties. Furthermore, they strongly argued that at a minimum, if a penalty payment was late, interest should accrue from the due date of the penalty, not January 1.

Response: The Agency clearly has the authority to collect interest on penalties. That authority comes from the Debt Collection Act, 31 U.S.C. 3717, which allows the head of an executive agency to charge a minimum annual rate of interest on an outstanding debt on a United States government claim. However, the Debt Collection Act provides that interest accrues from the date on which notice of the amount due is first mailed to the debtor. Therefore, the Agency has revised the rule to require that, for any penalty payment not made in full within 60 days of the end of the year in which excess emissions occurred, interest accrues from the date on which a demand notice from the Agency is mailed. Consistent with the Debt Collection Act, interest will not be charged if the claim is paid within 30 days after the date that notice of the amount due is mailed to the debtor.

VII. Discussion of Changes to Part 78—Administrative Appeals

Proposed subpart H of part 72 (renamed part 78) provided the procedures for administrative appeals of certain decisions of the Administrator under the Acid Rain Program. The basic approach to administrative appeals taken in the final part 78 rule is the same as that in the proposal, with a few changes. References in the proposal to the Administrator have been changed to refer, in the final rule, to the Environmental Appeals Board. In the past, appeals to the Administrator were delegated to the Chief Judicial Officer or decided by the Administrator. On February 13, 1992, the Agency established the Environmental Appeals Board of three members who will take over the appellate functions formerly exercised by the Chief Judicial Officer and the Administrator. (See 57 FR 5320, February 13, 1992.)

Further, references to "submit" or "submissions" have been changed to refer to "file" or "filing." This reflects the fact that, for purposes of applying the filing deadlines set forth in part 78, the date of receipt by the Administrator, Environmental Appeals Board, Presiding Officer, or Hearing Clerk (as appropriate), not of sending, is determinative. Also, as part of an effort to streamline the role, some provisions (e.g., proposed §§ 72.101(c)(2) and (d)) were deleted as unnecessary or redundant in light of the broad authority of the Presiding Officer under other provisions.

A. Expansion of Appeals to Allowance Rule Decisions

Proposed part 72, subpart H applied only to the Administrator's decisions concerning Acid Rain permits but the Agency stated in the preamble to the proposal that it was considering whether the appeals procedure should cover other decisions under the Acid Rain Program. The Agency received numerous comments requesting that the appeals procedures be expanded to cover other decisions. In particular, commenters noted the account error and dispute resolution process, proposed in § 73.37, applicable to allowance transfers recorded by the Administrator in the Allowance Tracking System. While the commenters generally supported that process, several commenters suggested that the appeals

procedure in part 72, subpart H be expanded to cover decisions of the Administrator under part 73, as a supplement to the account error and dispute resolution process.

Response: The Agency agrees that the administrative appeals procedure should be available for decisions of the Administrator under part 73. The final rules therefore include a provision allowing appeals regarding various decisions on the transfer, allocation, sale, return, or deduction of allowances by the Administrator. The administrative appeals procedure may not, however, be used to challenge provisions or requirements promulgated in regulations, including part 73.

Like the account error and dispute resolution procedure, only the authorized account representative of the account involved may appeal decisions under part 73 (e. g., allowance allocations under compliance options). This minimizes interference with the operation of the Allowance Tracking System and the allowance market. However, decisions under part 72 affecting allowances (e.g., decisions on compliance options resulting in allowance allocations) may be appealable by other interested persons.

B. Expansion to Monitoring Rule Decisions

Many commenters also supported using the administrative appeals procedure for decisions of the Administrator under part 75 because of the critical role that monitoring plays in the Acid Rain Program.

Response: The Agency agrees and the final rules allow monitoring decisions of the Administrator to be appealed under part 78, including the following: (1) The decision on petition for approval of an alternative monitoring system; (2) the approval or disapproval of a monitor certification or recertification: (3) finalization of annual emissions data, including retroactive adjustments based on audits; (4) the determination of the percentage emissions reduction achieved by Phase I extension technology; and (5) the determination on the acceptability of parametric missing data procedures. The Agency is providing for appeal of these decisions because they involve judgement and discretion on the part of the Administrator, rather than a blanket application of the regulations in part 75. These administrative appeals procedures may not be used to challenge the part 75 regulations.

C. Other Related Changes

Consistent with the expansion of the scope of the administrative appeals procedures in the final rule, the final rule applies these procedures to various decisions (in addition to the issuance or denial of permits) under the permits rule, including the issuance or denial of written exemptions for new and retired units, the determination of the incompleteness of an Acid Rain permit application, and the deduction or return of allowances under the compliance options. The procedures also now apply to the approval or disapproval of excess emissions offset plans and related allowance deductions under part 77.

Moreover, the significantly broader scope of Agency decisions subject to administrative appeal is likely to impose a much heavier burden on the Environmental Appeals Board and the Administrative Law Judges in terms of the number and complexity of the cases. Consequently, certain provisions of the proposal have been changed in order to ease that burden and ensure sufficient time for reasoned decision-making. In particular, under the final rule, the Presiding Officer in an evidentiary proceeding must issue a proposed decision "within a reasonable time" after completion of the hearing, rather than within 90 days as required in the proposal. Similarly, rulings on motions must be made within a reasonable time, rather than within 60 days.

Finally, the expansion of the appeals procedures means that they may apply to decisions on matters concerning which there was no opportunity to file comments or claims of error before the appeal. For the latter decisions, the final rule places the burden of going forward on the Administrator. Except for such cases, the petitioner has the burden of going forward. In all cases, the petitioner or, where the issuance or denial of an Acid Rain permit and a written exemption is involved, the prospective permittee has the burden of persuasion. This is consistent with the discussion of burden of proof in the portion of the preamble for the proposed rule addressing appeals.

VIII. Impact Analyses

A. Executive Order 12291

Under Executive Order 12291, the Administrator must judge whether a regulation is "major" and therefore subject to the requirement to conduct a Regulatory Impact Analysis (RIA). This rule package is "major" as defined in 1(b) of E.O. 12291 because the annual effect on the economy will be greater than $100 million. While the annual effect on the economy will be greater than $100 million, EPA does not anticipate major increases in prices, costs, or other significant adverse effects on competition, investment, productivity, or innovation or on the ability of United States enterprises to compete with foreign enterprises in domestic or foreign markets due to the proposed regulations.

Title IV, on its own without any implementing regulations, mandates extensive emission reductions and imposes continuous emission monitoring requirements on all sources. The reductions basically impose a reduction in emissions equal to the limit of allocated "basic" allowances. Such a program costs much more than the program assuming allowance trading, which provides for flexible, cost-effective compliance, the permits program, which provides for special compliance options such as the Phase I technology reserve program, and the monitoring program, which allows sources to implement alternative monitoring systems if they are demonstrated to match or exceed CEM systems.

A high base case and a low base case scenario were used in the analysis. These two cases were used by EPA to estimate the impacts of the legislation during the debate in Congress.

EPA's RIA evaluates the effects of a set of three regulations termed the "implementation regulations." These regulations are the General Provisions and Permits regulation; the Allowance System regulation, including tracking, transfers, auctions and sales, and conservation and renewable energy; and the Continuous Emissions Monitoring regulation. Collectively, this set of implementation regulations establishes and implements the core of the acid rain program. NO_x control costs were not included in this analysis.

EPA estimated the costs of achieving the reductions in SO_2 emissions under the statute and the implementation regulations for the time period from 1993 through 2010. While the total costs will be much lower in Phase I than Phase II, this analysis annualized the costs over the entire 18-year period. The statute without the implementation regulations (absent regulations case) imposes substantial costs, with the total annualized costs ranging from $1.6 to $2.5 billion per year. The costs of the implementation regulations (regulatory case), with total annualized costs ranging from $0.9 to $1.5 billion, are substantially less than the costs of the statute absent the implementation regulations. Thus, to achieve the mandated SO_2 emission reductions, the implementation regulations result in annual cost savings of between $0.7 and $1 billion compared to the statute absent the regulations.

While these costs are large in absolute terms, they are relatively small compared to the $200 billion average annual costs of generating electricity. The annualized costs of the implementation regulations are estimated to increase the annual costs of generating electricity by 0.5 to 1.2 percent.

For permitting under the regulatory case, program participants will incur administrative costs to obtain permits. The administrative cost for affected sources to obtain permits is estimated to be $0.5 million per year for Phase I (1995–1999) and $5.4 million per year for Phase II (2000–2010). Under the absent regulations case, no permitting would take place, so there would be no costs associated with permits.

In the regulatory case, EPA estimates that the total impact for participants in the allowance trading market will range between $15 and $30 million per year. This estimate includes market evaluation and transactions costs. These costs are based on the assumption that transactions costs will average 1.5 percent of the value of trades, which is assumed to range between $1 and $2 billion annually. In the absent regulations case, no trading would occur, so there would be no transaction costs in that case.

Although the auction and direct sale regulations are not included in this rulemaking, the costs are presented here for completeness. The total estimated annual costs to auction participants are minor, ranging from $13,600 to $81,300. The estimated total costs for direct sale applicants is $13,500 over 2 years. Assuming all IPP guarantee applications occur in the first year, the total cost to IPP guarantee applicants is estimated to be $225,000.

The conservation and renewable energy reserve is an optional program intended to provide additional incentive for utilities to conduct conservation programs. Affected sources that choose to participate in this program are likely to do so because it is economically beneficial. Under the regulatory case, the cost to affected sources that choose to participate associated with obtaining allowances from the conservation and renewable energy reserve is estimated to be $100,000 to $200,000 per year. These costs include the burden to assemble and submit an application to EPA each year in order to receive allowances from the reserve. Under the absent regulations case, no conservation and renewable energy reserve would be established.

For monitoring, the costs to the regulated community under the absent regulations case include costs associated with the installation and maintenance of continuous emissions monitors (CEMs), continuous opacity monitors (COMs), and flow monitoring systems, if they do not already have one in place. No alternative monitoring methods would be allowed and no data reporting costs would be incurred. In this case the estimated cost to the regulated community is $195 million annually.

The analysis considered five monitoring options under the regulatory case. All five options include operation and maintenance requirements. Option 1 presents the most stringent regulatory case and has an estimated annualized cost to electric utilities of $239 million dollars. Option 2 some monitoring exceptions and is estimated to cost $211 million annually. Option 3 exempts retiring plants from all monitoring requirements and has an estimated annualized cost of $234 million. Option 4 requires the use of standardized data reporting and recordkeeping requirements and is estimated to cost $235 million annually. Finally, EPA's proposed option, Option 5 has an estimated annualized cost of $184 million.

Both the absent regulation and regulatory cases will yield environmental benefits due to the 10 million ton reduction in SO_2 below 1980 levels. The reductions will result in less acid rain and sulfate exposure, and better visibility and local air quality. The implementation regulations are expected to generate additional long run benefits by creating incentives for the development of improved pollution control technology.

The analysis is contained in the Regulatory Impact Analysis (RIA) of the Acid Rain Regulations, July 1992, EPA, Office of Atmospheric and Indoor Air Programs.

This rule and RIA were submitted to the Office of Management and Budget (OMB) for review prior to publication as required by E.O. 12291.

B. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 requires each Federal agency to perform a Regulatory Flexibility Analysis for all rules that are likely to have a "significant impact on a substantial number of small entities."

For the purposes of this analysis, EPA used the Small Business Administration definition that a small electric power utility is one that generates a total of less than 4 billion kilowatt-hours per year. Not all small utilities are affected by the acid rain Title of the Act. Utilities will be unaffected if all of their units are: (1) Exempt (e.g., units use non-fossil sources of energy or simple gas turbines), or (2) below statutory minimums for electric generating capacity (e.g., generate less than 25 megawatts).

To examine the effects on small entities, EPA constructed six model small utilities of varying fuel type and size to represent most of the small utility population. Costs of SO_2 reductions are the incremental costs of acid rain controls, relative to the pre-statute case, under the absent regulations and regulatory cases. The implementation regulations lead to cost savings (or no change) relative to the absent regulations case for four of the six model utilities. However, even after the reductions in cost provided by the implementation regulations, the impacts on some small coal- and oil-fired utilities are expected to be significant. In the worst case, the regulatory cost to these utilities could represent between 6 to 7 percent of the average value of electricity produced in the year 2000. About 36, or one-third, of the 105 affected small utilities could face impacts of up to this magnitude. The other two-thirds have regulatory impacts that are comparable to or less than the impacts on all utilities as a group.

EPA's analysis concludes that virtually all of the impacts on small entities are caused by statutory provisions of the Act. Although EPA's regulations are intended to mitigate some of the burden on small businesses, the statutory provisions restrict the amount of relief that can be given. The implementation regulations are likely to result in substantial reductions in the costs imposed by the statute on small entities. As a percentage of the costs under the absent regulations case, the savings provided by the regulations may be similar to the savings for larger utilities. In addition, the rules provide an exemption from all title IV requirements for all new utility units that serve one or more generators, the nameplate capacities of which total 25 MWe or less, and that use fuels with a sulfur content less than or equal to .05% by weight. The rules also provide an exception from the NO_x monitoring requirements for gas-fired units with capacity factors of 10% or less. Therefore, by implementing these regulations, EPA has provided all the relief available under the statute to help the most affected small utilities. Based on this analysis and pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this attached rule, if promulgated, will not have a significant economic impact on a substantial number of small entities.

C. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* These requirements are not effective until OMB approves them and a technical amendment to that effect is published in the **Federal Register.**

The total public reporting burden for these regulations is estimated to range between 41,000 and 45,000 hours in 1993; 38,000 and 42,000 hours in 1994; and 64,000 and 67,000 hours in the first nine months of 1995. In order to obtain a permit, the public reporting burden to develop a permit application and compliance plan including certification of a designated representative is estimated to average a total of 370 hours per application. For tracking and transferring allowances, the public reporting burden to complete and submit an allowance tracking system new account application (if necessary) and an allowance transfer form is estimated to average 30 hours and 2 hours respectively. The burden for assembling and submitting an application to obtain allowances from the conservation and renewable energy reserve is estimated to average 80 hours per application. Finally, to meet the emissions monitoring requirements, the public reporting burden is estimated to average 40 hours per report per plant for preparing and submitting quarterly emissions data reports, and 20 hours per plant for submitting a one-time monitoring plan. These burden estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing the collection of information.

Send comments regarding these burden estimates or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch; U.S. Environmental Protection Agency; 401 M St., SW. (PM–223Y); Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 726 Jackson Place NW, Washington, DC 20503, marked "Attention: Desk Officer for EPA."

IX. Supporting Information

List of Subjects

40 CFR Parts 72 and 75

Air pollution control, Compliance plans, Continuous emissions monitors, Electric utilities, Incorporation by reference, Nitrogen oxides, Permits, Reporting and recordkeeping requirements, and Sulfur dioxide.

40 CFR Parts 73, 77, and 78

Air pollution control, Compliance plans, Continuous emissions monitors, Electric utilities, Nitrogen oxides, Permits, Reporting and recordkeeping requirements, Sulphur dioxide.

Dated: October 26, 1992.

William K. Reilly,

Administrator, U.S. Environmental Protection Agency.

For the reasons set forth in the preamble chapter I of title 40 of the Code of Federal Regulations is amended as follows:

1. Title 40 is amended by adding part 72 to read as follows:

PART 72—PERMITS REGULATION

Subpart A—Acid Rain Program General Provisions

Sec.

72.1 Purpose and scope.
72.2 Definitions.
72.3 Measurements, abbreviations, and acronyms.
72.4 Federal authority.
72.5 State authority.
72.6 Applicability.
72.7 New units exemption.
72.8 Retired units exemption.
72.9 Standard Requirements.
72.10 Availability of information.
72.11 Computation of time.
72.12 Administrative Appeals.
72.13 Incorporation by Reference.

Subpart B—Designated Representative

72.20 Authorization and responsibilities of the designated representative.
72.21 Submissions.
72.22 Alternate designated representative.
72.23 Changing the designated representative, alternate designated representative; changes in the owners and operators.
72.24 Certificate of representation.
72.25 Objections.

Subpart C—Acid Rain Applications

72.30 Requirement to apply.
72.31 Information requirements for Acid Rain permit applications.
72.32 Permit application shield and binding effect of permit application.
72.33 Identification of Dispatch System.

Subpart D—Acid Rain Compliance Plan and Compliance Options

72.40 General.
72.41 Phase I substitution plans.
72.42 Phase I extension plans.
72.43 Phase I reduced utilization plans.
72.44 Phase II repowering extensions.

Subpart E—Acid Rain Permit Contents

72.50 General.
72.51 Permit shield.

Subpart F—Federal Acid Rain Permit Issuance Procedures

72.60 General.
72.61 Completeness.
72.62 Draft permit.
72.63 Administrative record.
72.64 Statement of basis.
72.65 Public notice of opportunities for public comment.
72.66 Public comments.
72.67 Opportunity for public hearing.
72.68 Response to comments.
72.69 Issuance and effective date of acid rain permits.

Subpart G—Acid Rain Phase II Implementation

72.70 Relationship to title V operating permit program.
72.71 Approval of state programs—general.
72.72 State permit program approval criteria.
72.73 State issuance of Phase II permits.
72.74 Federal issuance of Phase II permits.

Subpart H—Permit Revisions

72.80 General.
72.81 Permit modifications.
72.82 Fast-track modifications.
72.83 Administrative permit amendment.
72.84 Automatic permit amendment.
72.85 Permit reopenings.

Subpart I—Compliance Certification

72.90 Annual compliance certification report.
72.91 Phase I unit adjusted utilization.
72.92 Phase I unit allowance surrender.
72.93 Units with Phase I extension plans.
72.94 Units with repowering extension plans.
72.95 Allowance deduction formula.
72.96 Administrator's action on compliance certifications.

Appendix A to Part 72—Methodology for Annualization of Emissions Limits

Appendix B to Part 72—Methodology for Conversion of Emissions Limits

Appendix C to Part 72—Actual 1985 Yearly SO_2 Emissions Calculations

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

Subpart A—Acid Rain Program General Provisions

§ 72.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish certain general provisions and the operating permit program requirements for affected sources and affected units under the Acid Rain Program, pursuant to title IV of the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law 101–549 (November 15, 1990).

(b) *Scope.* The regulations under this part set forth certain generally applicable provisions under the Acid Rain Program. The regulations also set forth requirements for obtaining three types of Acid Rain permits, during Phases I and II, for which an affected source may apply: Acid Rain permits

issued by the United States Environmental Protection Agency during Phase I; the Acid Rain portion of an operating permit issued by a State permitting authority during Phase II; and the Acid Rain portion of an operating permit issued by EPA when it is the permitting authority during Phase II. The requirements under this part supplement, and in some cases modify, the requirements under part 70 of this chapter and other regulations implementing title V for approving and implementing State operating permit programs and for federal issuance of operating permits under title V, as such requirements apply to affected sources under the Acid Rain Program.

§72.2 Definitions.

The terms used in this part, in parts 73, 75, 77 and 78 of this chapter, and in regulations implementing sections 407 and 410 of the Act, shall have the meanings set forth in the Act, including sections 302 and 402 of the Act, and in this section, as follows:

Account number means the identification number given by the Administrator to each Allowance Tracking System account pursuant to §73.31(d) of this chapter.

Acid Rain compliance option means one of the methods of compliance used by an affected unit under the Acid Rain Program as described in a compliance plan submitted and approved in accordance with subpart D of this part or regulations implementing section 407 of the Act.

Acid Rain emissions limitation means:

(1) For the purposes of sulfur dioxide emissions:

(i) The tonnage equivalent of the allowances authorized to be allocated to an affected unit for use in a calendar year under section 404 (a)(1) and (a)(3) of the Act, or the basic Phase II allowance allocations authorized to be allocated to an affected unit for use in a calendar year;

(ii) As adjusted:

(A) By allowances allocated by the Administrator pursuant to section 403, section 405 (a)(2), (a)(3), (b)(2), (c)(4), (d)(3), and (h)(2), and section 406 of the Act;

(B) By allowances allocated by the Administrator pursuant to subpart D of this part; and thereafter

(C) By allowance transfers to or from the compliance subaccount for that unit that were recorded or properly submitted for recordation by the allowance transfer deadline as provided in §73.35 of this chapter, after deductions and other adjustments are made pursuant to §73.34(c) of this chapter; and

(2) For purposes of nitrogen oxides emissions, the applicable limitation established by regulations promulgated by the Administrator pursuant to section 407 of the Act, as modified by an Acid Rain permit application submitted to the permitting authority, and an Acid Rain permit issued by the permitting authority, in accordance with regulations implementing section 407 of the Act.

Acid Rain emissions reduction requirement means a requirement under the Acid Rain Program to reduce the emissions of sulfur dioxide or nitrogen oxides from a unit to a specified level or by a specified percentage.

Acid Rain permit or permit means the legally binding written document, or portion of such document, issued by a permitting authority under this part (following an opportunity for appeal pursuant to part 78 of this chapter or any State administrative appeals procedure), including any permit revisions, specifying the Acid Rain Program requirements applicable to an affected source, to each affected unit at an affected source, and to the owners and operators and the designated representative of the affected source or the affected unit.

Acid Rain Program means the national sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established in accordance with title IV of the Act, this part and parts 73, 75, 77, and 78 of this chapter, and regulations implementing sections 407 and 410 of the Act.

Act means the Clean Air Act, 42 U.S.C. §7401, et seq. as amended by Public Law No. 101–549 (November 15, 1990).

Actual SO_2 emissions rate means the annual average sulfur dioxide emissions rate for the unit (expressed in lb/mmBtu), for the specified calendar year; *provided* that, if the unit is listed in the NADB, the "1985 actual SO_2 emissions rate" for the unit shall be the rate specified by the Administrator in the NADB under the data field "SO2RTE."

Add-on control means a pollution reduction control technology that operates independent of the combustion process.

Additional advance auction means the auction of advance allowances that were offered the previous year for sale in an advance sale.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Advance allowance means an allowance that may be used for purposes of compliance with a unit's Acid Rain sulfur dioxide emissions limitation requirements beginning no earlier than seven years following the year in which the allowance is first offered for sale.

Advance auction means an auction of advance allowances.

Advance sale means a sale of advance allowances.

Affected source means a source that includes one or more affected units.

Affected unit means a unit that is subject to any Acid Rain emissions reduction requirement or Acid Rain emissions limitation.

Affiliate shall have the meaning set forth in section 2(a)(11) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(11), as of November 15, 1990.

Allocate or allocation means the initial crediting of an allowance by the Administrator to an Allowance Tracking System unit account or general account.

Allowable SO_2 emissions rate means the most stringent federally enforceable emissions limitation for sulfur dioxide (in lb/mmBtu) applicable to the unit for the specified calendar year, or for such subsequent year as determined by the Administrator where such a limitation does not exist for the specified year; *provided* that, if the unit is listed in the NADB, the "1985 allowable SO_2 emissions rate" for the unit shall be the rate specified by the Administrator in the NADB under the data field "1985 annualized boiler SO_2 emission limit."

Allowance means an authorization by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during or after a specified calendar year.

Allowance deduction, or deduct when referring to allowances, means the permanent withdrawal of allowances by the Administrator from an Allowance Tracking System compliance subaccount to account for the number of the tons of SO_2 emissions from an affected unit for the calendar year, for tonnage emissions estimates calculated for periods of missing data as provided in part 75 of this chapter, or for any other allowance surrender obligations of the Acid Rain Program.

Allowances held or hold allowances means the allowances recorded by the Administrator, or submitted to the Administrator for recordation in accordance with §73.50 of this chapter, in an Allowance Tracking System account.

Allowance reserve means any bank of allowances established by the Administrator in the Allowance

Tracking System pursuant to sections 404(a)(2) (Phase I extension reserve), 404(g) (energy conservation and renewable energy reserve), or 416(b) (special allowance reserve) of the Act, and implemented in accordance with part 73, subpart B of this chapter.

Allowance Tracking or ATS means the Acid Rain Program system by which the Administrator allocates, records, deducts, and tracks allowances.

Allowance Tracking System account means an account in the Allowance Tracking System established by the Administrator for purposes of allocating, holding, transferring, and using allowances.

Allowance transfer deadline means midnight of January 30 or, if January 30 is not a business day, midnight of the first business day thereafter and is the deadline by which allowances may be submitted for recordation in an affected unit's compliance subaccount for the purposes of meeting the unit's Acid Rain emissions limitation requirements for sulfur dioxide for the previous calendar year.

Alternative monitoring system means a system or a component of a system designed to provide direct or indirect data of mass emissions per time period, pollutant concentrations, or volumetric flow, that is demonstrated to the Administrator as having the same precision, reliability, accessibility, and timeliness as the data provided by a certified CEMS or certified CEMS component in accordance with part 75 of this chapter.

As-fired means the taking of a fuel sample just prior to its introduction into the unit for combustion.

Auction subaccount means a subaccount in the Special Allowance Reserve, as specified in section 416(b) of the Act, which contains allowances to be sold at auction in the amount of 150,000 per year from calendar year 1995 through 1999, inclusive, and 200,000 per year for each year begnning in calendar year 2000, subject to the adjustments noted in the regulations in part 73, subpart E of this chapter.

Authorized account representative means a responsible natural person who is authorized, in accordance with part 73 of this chapter, to transfer and otherwise dispose of allowances held in an Allowance Tracking System general account; or, in the case of a unit account, the designated representative of the owners and operators of the affected unit.

Automated data acquisition and handling system means that component of the CEMS, COMS, or other emissions monitoring system approved by the Administrator for use in the Acid Rain Program, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, opacity monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by part 75 of this chapter.

Award means the conditional set-aside by the Administrator, based on the submission of an early ranking application pursuant to subpart D of this part, of an allowance from the Phase I extension reserve, for possible future allocation to a Phase I extension applicant's Allowance Tracking System unit account.

Baseline means the annual average quantity of fossil fuel consumed by a unit, measured in millions of British Thermal Units (expressed in mmBtu) for calendar years 1985 through 1987; *provided* that in the event that a unit is listed in the NADB, the baseline will be calculated for each unit-generator pair that includes the unit, and the unit's baseline will be the sum of such unit-generator baselines. The unit-generator baseline will be as provided in the NADB under the data field "BASE8587", as adjusted by the outage hours listed in the NADB under the data field "OUTAGEHR" in accordance with the following equation:

$$\text{Baseline}=\text{BASE8587}\times\{26280/(26280-\text{OUTAGEHR})\}\times\{36/(36-\text{months not on line})\}\times 10^{6}$$

"Months not on line" is the number of months during January 1985 through December 1987 prior to the commencement of firing for units that commenced firing in that period, i.e., the number of months, in that period, prior to the on-line month listed under the data field "BLRMNONL" and the on-line year listed in the data field "BLRYRONL" in the NADB.

Basic Phase II allowance allocations means:

(1) For calendar years 2000 through 2009 inclusive, allocations of allowances made by the Administrator pursuant to section 403 and section 405 (b)(1), (3), and (4); (c)(1), (2), (3), and (5); (d)(1), (2), (4), and (5); (e); (f); (g)(1), (2), (3), (4), and (5); (h)(1); (i); and (j).

(2) For each calendar year beginning in 2010, allocations of allowances made by the Administrator pursuant to section 403 and section 405 (b)(1), (3), and (4); (c)(1), (2), (3), and (5); (d)(1), (2), (4), and (5); (e); (f); (g)(1), (2), (3), (4), and (5); (h)(1) and (3); (i); and (j).

Bias means systematic error, resulting in measurements that will be either consistently low or high relative to the reference value.

Boiler means an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or any other medium.

By-pass stack means any duct, stack, or conduit through which emissions from an affected unit may or do pass to the atmosphere, which either augments or substitutes for the principal stack exhaust system or ductwork during any portion of the unit's operation.

Calibration error means the difference between:

(1) The response of gaseous monitor to a calibration gas and the known concentration of the calibration gas;

(2) The response of a flow monitor to a reference signal and the known value of the reference signal; or

(3) The response of a continuous opacity monitoring system to an attenuation filter and the known value of the filter after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

Calibration gas means:

(1) A standard reference material;

(2) A NIST/EPA-approved certified reference material;

(3) A Protocol 1 gas; or

(4) Zero ambient air material.

Capacity factor means the ratio of a unit's actual annual electric output (expressed in Mwe hr) and the unit's nameplate capacity times 8,760 hours.

CEMS precision or precision as applied to the monitoring requirements of part 75 of this chapter, means the closeness of a measurement to the actual measured value expressed as the uncertainty associated with repeated measurements of the same sample or of different samples from the same process (e.g., the random error associated with simultaneous measurements of a process made by more than one instrument). A measurement technique is determined to have increasing "precision" as the variation among the repeated measurements decreases.

Centroidal area means a representational concentric area that is geometrically similar to the stack or duct cross section, and is not greater than 1 percent of the stack or duct cross-sectional area.

Certificate of representation means the completed and signed submission required by § 72.20, for certifying the appointment of a designated representative for an affected source or a group of identified affected sources authorized to represent the owners and operators of such source(s) and of the affected units at such source(s) with regard to matters under the Acid Rain Program.

Certifying official, for purposes of part 73 of this chapter, means:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation;

(2) For partnership or sole proprietorship, a general partner or the proprietor, respectively; and

(3) For a local government entity or State, federal, or other public agency, either a principal executive officer or ranking elected official.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–92 "Standard Classification of Coals by Rank" (as incorporated by reference in § 72.13).

Coal-derived fuel means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal (e.g., pulverized coal, coal refuse, liquified or gasified coal, washed coal, chemically cleaned coal, coal-oil mixtures, and coke).

Coal-fired means the combustion of fuel consisting of coal or any coal-derived fuel (except a coal-derived gaseous fuel with a sulfur content no greater than natural gas), alone or in combination with any other fuel, where:

(1) For purposes of the requirements of part 75 of this chapter, a unit is "coal-fired" independent of the percentage of coal or coal-derived fuel consumed in any calendar year (expressed in mmBtu); and

(2) For all other purposes under the Acid Rain Program (including for calculating allowance allocations pursuant to part 73 of this chapter and applicability of the requirements of section 407 of the Act), a unit is "coal-fired" if it uses coal or coal-derived fuel as its primary fuel (expressed in mmBtu); *provided* that, if the unit is listed in the NADB, the primary fuel is the fuel listed in the NADB under the data field "PRIMEFUEL".

Cogeneration unit means a unit that has equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating or cooling purposes, through the sequential use of energy.

Commence commercial operation means to have begun to generate electricity for sale, including the sale of test generation.

Commence construction means that an owner or operator has either undertaken a continuous program of construction or has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

Commence operation means to have begun any mechanical, chemical, or electronic process, including start-up of an emissions control technology or emissions monitor or of a unit's combustion chamber.

Common stack means the exhaust of emissions from two or more units through a single flue.

Compensating unit means a unit that is not otherwise subject to Acid Rain emissions limitation or Acid Rain emissions reduction requirements during Phase I and that is designated as a Phase I unit in a reduced utilization plan under § 72.43; *provided* that a unit that is not an affected unit under the Acid Rain Program shall not be a compensating unit.

Compliance certification means a submission to the Administrator or permitting authority, as appropriate, that is required by this part, by part 73, 75, 77, or 78, or by regulations implementing sections 407 or 410 of the Act to report an affected source or an affected unit's compliance or non-compliance with a provision of the Acid Rain Program and that is signed and verified by the designated representative in accordance with subparts B and I of this part and the Acid Rain Program regulations generally.

Compliance plan, for purposes of the Acid Rain Program, means the document submitted for an affected source in accordance with subpart C of this part, specifying the method(s) (including one or more Acid Rain compliance options under subpart D or regulations implementing section 407 of the Act) by which each affected unit at the source will meet the applicable Acid Rain emissions limitation and Acid Rain emissions reduction requirements.

Compliance subaccount means the subaccount in an affected unit's Allowance Tracking System account, established pursuant to § 73.31 (a) or (b) of this chapter, in which are held, from the date that allowances for the current calendar year are recorded under § 73.34(a) until December 31, allowances available for use by the unit in the current calendar year and, after December 31 until the date that deductions are made under § 73.35(b), allowances available for use by the unit in the preceding calendar year, for the purpose of meeting the unit's Acid Rain emissions limitation for sulfur dioxide.

Compliance use date means the first calendar year for which an allowance may be used for purposes of meeting a unit's Acid Rain emissions limitation for sulfur dioxide.

Conservation Verification Protocol means a methodology developed by the Administrator for calculating the kilowatt hour savings from energy conservation measures and improved unit efficiency measures for the purposes of title IV of the Act.

Construction means fabrication, erection, or installation of a unit or any portion of a unit.

Consumer Price Index or CPI means, for purposes of the Acid Rain Program, the U.S. Department of Labor, Bureau of Labor Statistics unadjusted Consumer Price Index for All Urban Consumers for the U.S. city average, for All Items on the latest reference base, or if such index is no longer published, such other index as the Administrator in his or her discretion determines meets the requirements of the Clean Air Act Amendments of 1990.

(1) *CPI (1990)* means the CPI for all urban consumers for the month of August 1989. The "CPI (1990)" is 124.6 (with 1982–1984=100). Beginning in the month for which a new reference base is established, "CPI (1990)" will be the CPI value for August 1989 on the new reference base.

(2) *CPI (year)* means the CPI for all urban consumers for the month of August of the previous year.

Continuous emission monitoring system or CEMS means the equipment required by part 75 of this chapter used to sample, analyze, measure, and provide, by readings taken at least once every 15 minutes, a permanent record of emissions, expressed in pounds per hour (lb/hr) for sulfur dioxide and in pounds per million British thermal units (lb/mmBtu) for nitrogen oxides. The following systems are component parts included in a continuous emission monitoring system:

(1) Sulfur dioxide pollutant concentration monitor;

(2) Flow monitor;

(3) Nitrogen oxides pollutant concentration monitors;

(4) Diluent gas monitor (oxygen or carbon dioxide);

(5) A continuous moisture monitor when such monitoring is required by part 75 of this chapter; and

(6) A data acquisition and handling system.

Continuous opacity monitoring system or COMS means the equipment required by part 75 of this chapter to sample, measure, analyze, and provide, with readings taken at least once every 6 minutes, a permanent record of opacity or transmittance. The following systems are component parts included

in a continuous opacity monitoring system:

(1) Opacity monitor; and

(2) A data acquisition and handling system.

Control unit means a unit employing a qualifying Phase I technology in accordance with a Phase I extension plan under § 72.42.

Current year subaccount means the subaccount in an Allowance Tracking System general account, established pursuant to § 73.31(c) of this chapter, in which are held allowances that may be transferred to a unit's compliance subaccount for use by the unit for the purpose of meeting its Acid Rain sulfur dioxide emissions limitation.

Customer means a purchaser of electricity not for purposes of transmission or resale.

Decisional body means any EPA employee who is or may reasonably be expected to act in a decision-making role in a proceeding under part 78 of this chapter, including the Administrator, a member of the Environmental Appeals Board, and a Presiding Officer, and any staff of any such person who are participating in the decisional process.

Demand-side measure means a measure:

(1) To improve the efficiency of consumption of electricity from a utility by customers of the utility; or

(2) To reduce the amount of consumption of electricity from a utility by customers of the utility without increasing the use by the customer of fuel other than: Biomass (i.e., combustible energy-producing materials from biological sources, which include wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste), solar, geothermal, or wind resources; or industrial waste gases where the party making the submission involved certifies that there is no net increase in sulfur dioxide emissions from the use of such gases. "Demand-side measure" includes the measures listed in part 73, Appendix A, section 1 of this chapter.

Designated representative means a responsible natural person authorized by the owners and operators of an affected source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with subpart B of this part, to represent and legally bind each owner and operator, as a matter of federal law, in matters pertaining to the Acid Rain Program. Whenever the term "responsible official" is used in part 70 of this chapter, in any other regulations implementing title V of the Act, or in a State operating permit program, it shall be deemed to refer to the "designated representative" with regard to all matters under the Acid Rain Program.

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

Diesel reciprocating engine unit means an internal combustion engine that combusts only diesel fuel and that thereby generates electricity through the operation of pistons, rather than by heating steam or water.

Diluent gas means a major gaseous constituent in a gaseous pollutant mixture, which in the case of emissions from fossil fuel-fired units are carbon dioxide and oxygen.

Diluent gas monitor means that component of the continuous emission monitoring system that measures the diluent gas concentration in a unit's flue gas.

Direct Sale Subaccount means a subaccount in the Special Allowance Reserve, as specified in section 416(b) of the Act, which contains Phase II allowances to be sold in the amount of 25,000 per year, from calendar year 1993 to 1999, inclusive, and of 50,000 per year for each year beginning in calendar year 2000, subject to the adjustments noted in the regulations at part 73, subpart E of this chapter.

Dispatch means the assignment within a dispatch system of generating levels to specific units and generators to effect the reliable and economical supply of electricity, as customer demand rises or falls, and includes:

(1) The operation of high-voltage lines, substations, and related equipment; and

(2) The scheduling of generation for the purpose of supplying electricity to other utilities over interconnecting transmission lines.

Dispatch system means either:

(1) A specified unit and generator or specified group of units, and portions of units, and generators that are interconnected and centrally dispatched, *provided* that the requirements of § 72.33 are met; or

(2) In the event the requirements specified in paragraph (1) of this definition are not met, the unit and generator or group of units and generators that make up one utility system.

Draft Acid Rain permit or draft permit means the version of the Acid Rain permit, or the Acid Rain portion of an operating permit, that a permitting authority offers for public comment.

Dual-fuel reciprocating engine unit means an internal combustion engine that combusts any combination of natural gas and diesel fuel and that thereby generates electricity through the operation of pistons, rather than by heating steam or water.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative and as determined by the Administrator, in accordance with the emissions monitoring requirements of part 75 of this chapter.

Environmental Appeals Board means the three-member board established pursuant to § 1.25(e) of this chapter and authorized to hear appeals pursuant to part 78 of this chapter.

EPA means the United States Environmental Protection Agency.

EPA trial staff means an employee of EPA, whether temporary or permanent, who has been designated by the Administrator to investigate, litigate, and present evidence, arguments, and positions of EPA in any evidentiary hearing under part 78 of this chapter. Any EPA or permitting authority employee, consultant, or contractor who is called as a witness in the evidentiary hearing by EPA trial staff shall be deemed to be "EPA trial staff".

Equivalent diameter means a value, calculated using the equation in paragraph 2.1 of Method 1 in part 60, Appendix A of this chapter, and used to determine the upstream and downstream distances for locating CEMS or CEMS components in flues or stacks with rectangular cross sections.

Ex parte communication means any communication, written or oral, relating to the merits of an adjudicatory proceeding under part 78 of this chapter, that was not originally included or stated in the administrative record, in a pleading, or in an evidentiary hearing or oral argument under part 78 of this chapter, between the decisional body and any interested person outside EPA or any EPA trial staff. Ex parte communication shall not include:

(1) Communication between EPA employees other than between EPA trial staff and a member of the decisional body; or

(2) Communication between the decisional body and interested persons outside the Agency, or EPA trial staff, where all parties to the proceeding have received prior written notice of the proposed communication and are given an opportunity to be present and to participate therein.

Excess emissions means:

(1) Any tonnage of sulfur dioxide emitted by an affected unit during a

calendar year that exceeds the Acid Rain emissions limitation for sulfur dioxide for the unit; and

(2) Any tonnage of nitrogen oxide emitted by an affected unit during a calendar year that exceeds the annual tonnage equivalent of the Acid Rain emissions limitation for nitrogen oxides applicable to the affected unit taking into account the unit's heat input for the year.

Existing unit means a unit (including a unit subject to section 111 of the Act) that commenced commercial operation before November 15, 1990 and that on that date served a generator with a nameplate capacity of greater than 25 MWe. "Existing unit" does not include simple combustion turbines or any unit that on November 15, 1990 served only generators with a nameplate capacity of 25 MWe or less. Any "existing unit" that is modified, reconstructed, or repowered after November 15, 1990 shall continue to be an "existing unit."

Facility means any institutional, commercial, or industrial structure, installation, plant, source, or building.

File means to send or transmit a document, information, or correspondence to the official custody of the person specified to take possession in accordance with the applicable regulation. Compliance with any "filing" deadline shall be determined by the date that person receives the document, information, or correspondence.

Flow meter accuracy means the closeness of the measurement made by a flow meter to the reference value of the fuel flow being measured, expressed as the difference between the measurement and the reference value.

Flow monitor means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.

Flue means a conduit or duct through which gases or other matter are exhausted to the atmosphere.

Forced outage means the removal of a unit from service due to an unplanned component failure or other unplanned condition that requires such removal immediately or within 7 days from the onset of the unplanned component failure or condition. For purposes of §§ 72.43, 72.91, and 72.92, "forced outage" also includes a partial reduction in the heat input or electrical output due to an unplanned component failure or other unplanned condition that requires such reduction immediately or within 7 days from the onset of the unplanned component failure or condition.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil fuel-fired means the combustion of fossil fuel or any derivative of fossil fuel, alone or in combination with any other fuel, independent of the percentage of fossil fuel consumed in any calendar year (expressed in mmBtu).

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) as defined by the American Society for Testing and Materials in ASTM D396–90a, "Standard Specification for Fuel Oils" (incorporated by reference in § 72.13), and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid or gaseous state; *provided* that for purposes of the monitoring requirements of part 75 of this chapter, "fuel oil" shall be limited to the petroleum-based fuels for which applicable ASTM methods are specified in Appendices D, E, or F of part 75 of this chapter.

Fuel supply agreement means a legally binding agreement between a new IPP or a firm associated with a new IPP and a fuel supplier that establishes the terms and conditions under which the fuel supplier commits to provide fuel to be delivered to the new IPP.

Future year subaccount means a subaccount in an Allowance Tracking System account, established by the Administrator pursuant to § 73.31 of this chapter, in which allowances are held for one of the 30 years following the later of 1995 or a current calendar year following 1995.

Gas-fired means the combustion of: Natural gas, or a coal-derived gaseous fuel with a sulfur content no greater than natural gas, for at least 90 percent of the average annual heat input during the previous three calendar years and for at least 85 percent of the annual heat input in each of those calendar years; and any fuel other than coal or any other coal-derived fuel for the remaining heat input, if any; *provided* that for purposes of the monitoring exceptions of part 75 of this chapter, the supplemental fuel used in addition to natural gas, if any, shall be limited to gaseous fuels containing no more sulfur than natural gas or, as specified in the monitoring exceptions, fuel oil.

General account means an Allowance Tracking System account that is not a unit account.

Generator means a device that produces electricity and was or would have been required to be reported as a generating unit pursuant to the United States Department of Energy Form 860 (1990 edition).

Hearing clerk means an EPA employee designated by the Administrator to establish a repository for all books, records, documents, and other materials relating to proceedings under part 78 of this chapter.

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

Hybrid generation facility means a plant that generates electrical energy derived from a combination of qualified renewable energy (wind, solar, biomass, or geothermal) and one or more other energy resources.

Independent auditor means a professional engineer who is not an employee or agent of the source being audited.

Interested person means any person who submitted written comments or testified at a public hearing on the draft permit or other matter subject to notice and comment under the Acid Rain Program or any person who submitted his or her name to the Administrator or the permitting authority, as appropriate, to be placed on a list of persons interested in such matter. The Administrator or the permitting authority may update the list of interested persons from time to time by requesting additional written indication of continued interest from the persons listed and may delete from the list the name of any person failing to respond as requested.

Investor-owned utility means a utility that is organized as a tax-paying for-profit business.

Kilowatthour saved or *savings* means the net savings in electricity use (expressed in Kwh) that result directly from a utility's energy conservation measures or programs.

Least-cost plan or *least-cost planning process* means an energy conservation and electric power planning methodology meeting the requirements of § 73.82(a)(4) of this chapter.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified generating unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period equal to or greater than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit was built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Mail or serve by mail means to submit or serve by means other than personal service.

Maximum potential NO_x emission rate means the emission rate of nitrogen oxides (in lb/mmBtu) calculated in accordance with section 3 of appendix F of part 75 of this chapter, using the maximum potential nitrogen oxides concentration and either the minimum oxygen concentration (in % O_2) or the maximum carbon dioxide concentration (in % CO_2) as defined in section 2 of appendix A of part 77 of this chapter.

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

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

Monitor operating hour means any hour or portion thereof over which a CEMS, COMS, or other monitoring system approved by the Administrator under part 75 of this chapter is operating regardless of the number of measurements (i.e., data points) collected during the hour.

Most stringent federally enforceable emissions limitation means the most stringent emissions limitation for a given pollutant applicable to the unit, which has been approved by the Administrator under the Act, whether in a State implementation plan approved pursuant to title I of the Act, a new source performance standard, or otherwise. To determine the most stringent emissions limitation for sulfur dioxide, each limitation shall be converted to lbs/mmBtu, using the appropriate conversion factors in appendix B of this part; *provided* that for determining the most stringent emissions limitation for sulfur dioxide for 1985, each limitation shall also be annualized, using the appropriate annualization factors in appendix A of this part.

Multi-header generator means a generator served by ductwork from more than one unit.

Multi-header unit means a unit with ductwork serving more than one generator.

Nameplate capacity means the maximum electrical generating output (expressed in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings, as listed in the NADB under the data field "NAMECAP" if the generator is listed in the NADB or as measured in accordance with the United States Department of Energy standards if the generator is not listed in the NADB.

National Allowance Data Base or *NADB* means the data base established by the Administrator under section 402(4)(C) of the Act.

Natural gas means a naturally occurring fluid mixture of hydrocarbons containing little or no sulfur (e.g., methane, ethane, or propane), produced in geological formations beneath the Earth's surface, and maintaining a gaseous state at standard atmospheric temperature and pressure conditions under ordinary conditions.

NERC region means the North American Electric Reliability Council region or, if any, subregion.

Net income neutrality means, in the case of energy conservation measures undertaken by an investor-owned utility whose rates are regulated by a State utility regulatory authority, rates and charges established by the State utility regulatory authority that ensure that the net income earned by the utility on its State-jurisdictional equity investment will be *no lower* as a consequence of its expenditures on cost-effective qualified energy conservation measures and any associated lost sales than it would have been had the utility not made such expenditures, or that the State utility regulatory authority has implemented a ratemaking approach designed to meet this objective.

New independent power production facility or *new IPP* means a unit that:

(1) Commences commercial operation on or after November 15, 1990;

(2) Is nonrecourse project-financed, as defined in 10 CFR part 715;

(3) Sells 80% of electricity generated at wholesale; and

(4) Does not sell electricity to any affiliate or, if it does, demonstrates it cannot obtain the required allowances from such an affiliate.

New unit means a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 MWe or less or that is a simple combustion turbine.

Ninetieth (90th) percentile means a value that would divide an ordered set of increasing values so that at least 90 percent are less than or equal to the value and at least 10 percent are greater than or equal to the value.

Ninety-fifth (95th) percentile means a value that would divide an ordered set of increasing values so that at least 95 percent of the set are less than or equal to the value and at least 5 percent are greater than or equal to the value.

NIST/EPA-approved certified reference material or NIST/EPA-approved CRM means a calibration gas mixture that has been approved by EPA and the National Institutes of Standards and Technologies (NIST) as having specific known chemical or physical property values certified by a technically valid procedure as evidenced by a certificate or other documentation issued by a certifying standard-setting body.

Offset plan means a plan pursuant to part 77 of this chapter for offsetting excess emissions of sulfur dioxide that have occurred at an affected unit in any calendar year.

Oil-fired means the combustion of: fuel oil for more than 10 percent of the average annual heat input during the previous three calendar years or for more than 15 percent of the annual heat input in any one of those calendar years; and any solid, liquid, or gaseous fuel, other than coal or any other coal-derived fuel (except a coal-derived gaseous fuel with a sulfur content no greater than natural gas), for the remaining heat input, if any; *provided* that for purposes of the monitoring exceptions of part 75 of this chapter, the supplemental fuel used in addition to fuel oil, if any, shall be limited to gaseous fuels, other than a coal-derived fuel.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating permit means a permit issued under part 70 of this chapter and any other regulations implementing title V of the Act.

Out-of-control period means any period:

(1) Beginning with the hour corresponding to the completion of a daily calibration error, linearity check, or quality assurance audit that indicates that the instrument is not measuring and recording within the applicable performance specifications; and

(2) Ending with the hour corresponding to the completion of an additional calibration error, linearity

check, or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the applicable performance specifications.

Oversubscription payment deadline means 30 calendar days prior to the allowance transfer deadline.

Owner means any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected unit; or

(2) Any holder of a leasehold interest in an affected unit; or

(3) Any purchaser of power from an affected unit under a life-of-the-unit, firm power contractual arrangement as that term is defined herein and used in section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit; or

(4) With respect to any Allowance Tracking System general account, any person identified in the submission required by § 73.31(c) of this chapter that is subject to the binding agreement for the authorized account representative to represent that person's ownership interest with respect to allowances.

Owner or operator means any person who is an owner or who operates, controls, or supervises an affected unit or affected source and shall include, but not be limited to, any holding company, utility system, or plant manager of an affected unit or affected source.

Peaking unit means a unit that has:

(1) an average capacity factor of no more than 10 percent during the previous 3 calendar years and

(2) a capacity factor of no more than 20 percent in each of those calendar years.

Permit revision means a permit modification, fast track modification, administrative permit amendment, or automatic permit amendment, as provided in subpart H of this part.

Permitting authority means either

(1) the Administrator in the case of issuance and administration of Acid Rain permits or

(2) the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue proposed Acid Rain permits under subpart G of this part and the other regulations promulgated pursuant to titles IV and V of the Act.

Person includes an individual, corporation, partnership, association, State, municipality, political subdivision of a State, any agency, department, or instrumentality of the United States, and any officer, agent, or employee thereof.

Phase I means the Acid Rain Program period beginning January 1, 1995 and ending December 31, 1999.

Phase I unit means any affected unit that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation beginning in Phase I.

Phase II means the Acid Rain Program period beginning January 1, 2000, and continuing into the future thereafter.

Phase II unit means any affected unit that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation during Phase II only.

Pollutant concentration monitor means that component of the continuous emission monitoring system that measures the concentration of a pollutant in a unit's flue gas.

Power distribution system means the portion of an electricity grid owned or operated by a utility that is dedicated to delivering electric energy to customers.

Power sales agreement is a legally-binding agreement between a new IPP or a firm associated with a new IPP and a regulated electric utility that establishes the terms and conditions for the sale of power from the new IPP to the utility.

Presiding Officer means an Administrative Law Judge appointed under 5 U.S.C. 3105 and designated to preside at a hearing in an appeal under part 78 of this chapter or an EPA lawyer designated to preside at any such hearing under § 78.6(b)(3)(ii) of this chapter.

Primary fuel or primary fuel supply means the main fuel type (expressed in mmBtu) consumed by an affected unit for the applicable calendar year.

Proposed Acid Rain permit or proposed permit means, in the case of a State operating permit program, the version of an Acid Rain permit that the permitting authority submits to the Administrator after the public comment period, but prior to completion of the EPA permit review period, as provided for in part 70 of this chapter.

Protocol 1 gas means a calibration gas mixture prepared and analyzed according to the "Procedure for NBS-Traceable Certification of Compressed Gas Working Standards Used for Calibration and Audit of Continuous Emission Monitors ("Revised Traceability Protocol No. 1"),'' Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods, Section 3.04, EPA–600/4–77–027b, June 1987 (set forth in Appendix H of part 75 of this chapter).

Qualifying Phase I technology means a technological system of continuous emission reduction that is demonstrated to achieve a ninety (90) percent (or greater) reduction in emissions of sulfur dioxide from the emissions that would have resulted from the use of fossil fuels that were not subject to treatment prior to combustion, as provided in § 72.42.

Qualifying repowering technology means:

(1) Replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990; or

(2) Any oil- or gas-fired unit that has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Quality assured monitor operating hour means any hour over which a certified CEMS, COMS, or other monitoring system approved by the Administrator under part 75 of this chapter, is operating: in accordance with § 75.10(e) and (f); and within the performance specifications set forth in part 75, Appendix A of this chapter and the quality control/quality assurance procedures set forth in part 75, appendix B of this chapter, without unscheduled maintenance, repair, or adjustment.

Receive or receipt of means the date the Administrator or a permitting authority comes into possession of information or correspondence (whether sent in writing or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the information or correspondence, by the Administrator or the permitting authority in the regular course of business.

Recordation, record, or recorded means, with regard to allowances, the transfer of allowances by the

Administrator from one Allowance Tracking System account or subaccount to another.

Reduced utilization means a reduction, during any calendar year in Phase I, in the heat input (expressed in mmBtu for the calendar year) at a Phase I unit below the unit's baseline, where such reduction subjects the unit to the requirement to file a reduced utilization plan under § 72.43.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in part 60, Appendix A of this chapter.

Reference value or reference signal means the known concentration of a calibration gas, the known value of an electronic calibration signal, or the known value of any other measurement standard approved by the Administrator, assumed to be the true value for the pollutant or diluent concentration or volumetric flow being measured.

Relative accuracy means a statistic designed to provide a measure of the systematic and random errors associated with data from continuous emission monitoring systems, and is expressed as the absolute mean difference between the pollutant concentration or volumetric flow measured by the pollutant concentration or flow monitor and the value determined by the applicable reference method(s) plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests in accordance with part 75 of this chapter.

Schedule of compliance means an enforceable sequence of actions, measures, or operations designed to achieve or maintain compliance, or correct non-compliance, with an applicable requirement of the Acid Rain Program, including any applicable Acid Rain permit requirement.

Secretary of Energy means the Secretary of the United States Department of Energy or the Secretary's duly authorized representative.

Serial number means, when referring to allowances, the unique identification number assigned to each allowance by the Administrator, pursuant to § 73.34(d) of this chapter.

Simple combustion turbine means a unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel. This term includes combined cycle units without auxiliary firing but excludes such units with auxiliary firing.

Site lease, as used in part 73, subpart E of this chapter, means a legally-binding agreement signed between a new IPP or a firm associated with a new IPP and a site owner that establishes the terms and conditions under which the new IPP or the firm associated with the new IPP has the binding right to utilize a specific site for the purposes of operating or constructing the new IPP.

Source means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the Act. For purposes of section 502(c) of the Act, a "source", including a "source" with multiple units, shall be considered a single "facility."

Span means the range of values that a monitor component is required to be capable of measuring under part 75 of this chapter.

Spot allowance means an allowance that may be used for purposes of compliance with a unit's Acid Rain sulfur dioxide emissions limitation requirements beginning in the year in which the allowance is offered for sale.

Spot Auction means an auction of a spot allowance.

Spot Sale means a sale of a spot allowance.

Stack means a structure that includes one or more flues and the housing for the flues.

Standard conditions means 68 °F at 1 atm (29.92 in. of mercury).

Standard reference material or *SRM* means a calibration gas mixture issued and certified by NIST as having specific known chemical or physical property values.

State means one of the 48 contiguous States and the District of Columbia and includes any non-federal authorities, including local agencies, interstate associations, and State-wide agencies with approved State operating permit programs. The term "State" shall have its conventional meaning where such meaning is clear from the context.

State operating permit program means an operating permit program that the Administrator has approved as meeting the requirements of titles IV and V of the Act, part 70 of this chapter, and this part, including subpart G of this part.

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

Steam sales agreement is a legally-binding agreement between a new IPP or a firm associated with a new IPP and an industrial or commercial establishment requiring steam that sets the terms and conditions under which the new IPP will provide steam to the establishment.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service certified mail with the official postmark or, if service is by the Administrator or the permitting authority, by any other mail service by the United States Postal Service; or

(3) By other means with an equivalent time and date mark used in the regular course of business to indicate the date of dispatch or transmission and a record of prompt delivery. Compliance with any "submission", "service", or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Substitute data means emissions or volumetric flow data provided to assure 100 percent recording and reporting of emissions when all or part of the continuous emission monitoring system is not functional or is operating outside applicable performance specifications.

Substitution unit means an affected unit, other than a unit under section 410 of the Act, that is designated as a Phase I unit in a substitution plan under § 72.41.

Sulfur-free generation means: the generation of electricity by a process that does not have any emissions of sulfur dioxide, including hydroelectric, nuclear, solar and wind generation. A "sulfur-free generator" is a generator that produces such "sulfur-free generation."

Supply-side measure means a measure to improve the efficiency of the generation, transmission, or distribution of electricity, implemented by a utility in connection with its operations or facilities to provide electricity to its customers, and includes the measures set forth in part 73, Appendix A, section 2 of this chapter.

Ton or tonnage means any "short ton" (i.e., 2,000 pounds). For the purpose of determining compliance with the Acid Rain emissions limitations and reduction requirements, total tons for a year shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with part 75 of this chapter, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed not to equal any ton.

Transfer unit means a Phase I unit that transfers all or part of its Phase I

emission reduction obligations to a control unit designated pursuant to a Phase I extension plan under § 72.42.

Underutilization means a reduction, during any calendar year in Phase I, of the heat input (expressed in mmBtu for the calendar year) at a Phase I unit below the unit's baseline.

Unit means a fossil fuel-fired combustion device.

Unit account means an Allowance Tracking System account, established by the Administrator for an affected unit pursuant to § 73.31 (a) or (b) of this chapter.

Unit load means the total (i.e., gross) output of a unit or source in any calendar year (or other specified time period) produced by combusting a given heat input of fuel, expressed in terms of:

(1) The total electrical generation (MWe) for use within the plant and for sale; or

(2) In the case of a unit or source that uses part of its heat input for purposes other than electrical generation, the total steam pressure (psia) produced by the unit or source.

Unit operating hours means, when referring to the availability of a monitoring system, the number of hours (or fraction of an hour) that a unit combusts any fuel; and, in the case of a COMS availability, includes the number of hours (or fraction of an hour) after combustion has ceased when fans are operating.

Utility means any person that sells electricity.

Utility competitive bid solicitation is a public request from a regulated utility for offers to the utility for meeting future generating needs. A new IPP may be regarded as having been "selected" in such solicitation pursuant to section 405(g)(6)(A)(iv) of the Act if the utility has named the IPP as a project with which it intends to negotiate a power sales agreement.

Utility regulatory authority means an authority, board, commission, or other entity (limited to the local-, State-, or federal-level, whenever so specified) responsible for overseeing the business operations of utilities located within its jurisdiction, including, but not limited to, utility rates and charges to customers.

Utility system means all interconnected units and generators controlled by the same utility operating company, as reported in the NADB under the data field "UTILNAME".

Utility unit means a unit owned or operated by a utility:

(1) That serves a generator in any State that produces electricity for sale, or

(2) That during 1985, served a generator in any State that produced electricity for sale.

(3) Notwithstanding paragraphs (1) and (2) of this definition, a unit that was in operation during 1985, but did not serve a generator that produced electricity for sale during 1985, and did not commence commercial operation on or after November 15, 1990 is not a utility unit for purposes of the Acid Rain Program.

(4) Notwithstanding paragraphs (1) and (2) of this definition, a unit that cogenerates steam and electricity is not a utility unit for purposes of the Acid Rain Program, unless the unit is constructed for the purpose of supplying, or commences construction after November 15, 1990 and supplies, more than one-third of its potential electrical output capacity and more than 25 MWe output to any power distribution system for sale.

Utilization means the heat input (expressed in mmBtu/time) for a unit.

Volumetric flow means the rate of movement of a specified volume of gas past a cross-sectional area (e.g., cubic feet per hour).

Zero ambient air material means a gas that consists of ambient air and that is vendor-certified to contain: traceable concentrations respectively of SO_2, NO_x, and THC below 0.1 ppm; a concentration of CO below 1 ppm; and a concentration of CO_2 below 400 ppm.

§ 72.3 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

acfh—actual cubic feet per hour.
atm—atmosphere.
bbl—barrel.
Btu—British thermal unit.
°C—degree Celsius (centigrade).
cfm—cubic feet per minute.
cm—centimeter.
dcf—dry cubic feet.
DOE—Department of Energy.
dscf—dry cubic feet at standard conditions.
dscfh—dry cubic feet per hour at standard conditions.
EIA—Energy Information Administration.
eq—equivalent.
°F—degree Fahrenheit.
fps—feet per second.
gal—gallon.
hr—hour.
in—inch.
°K—degree Kelvin.
Kwh—kilowatt hour.
lb—pounds.
m—meter.
mmBtu—million Btu.
min—minute.
mol. wt.—molecular weight.
MWe—megawatt electrical.
MWge—gross megawatt electrical.
ppm—parts per million.
psi—pounds per square inch.
°R—degree Rankine.
scf—cubic feet at standard conditions.
scfh—cubic feet per hour at standard conditions.
sec—second.
std—at standard conditions.
CO_2—carbon dioxide.
NO_x—nitrogen oxides.
O_2—oxygen.
THC—total hydrocarbon content.
SO_2—sulfur dioxide.

§ 72.4 Federal authority.

(a) The Administrator reserves all authority under sections 112(r)(9), 113, 114, 120, 301, 303, 304, 306, and 307(a) of the Act, including, but not limited to, the authority to:

(1) Secure information needed for the purpose of developing, revising, or implementing, or of determining whether any person is in violation of, any standard, method, requirement, or prohibition of the Act, this part, parts 73, 75, 77, and 78 of this chapter, and regulations implementing sections 407 and 410 of the Act;

(2) Make inspections, conduct tests, examine records, and require an owner or operator of an affected unit to submit information reasonably required for the purpose of developing, revising, or implementing, or of determining whether any person is in violation of, any standard, method, requirement, or prohibition of the Act, this part, parts 73, 75, 77, and 78 of this chapter, and regulations implementing sections 407 and 410 of the Act; and

(3) Issue orders, call witnesses, and compel the production of documents.

(b) The Administrator reserves the right under title IV of the Act to take any action necessary to protect the orderly and competitive functioning of the allowance system, including actions to prevent fraud and misrepresentation.

§ 72.5 State authority.

Consistent with section 116 of the Act, the provisions of the Acid Rain Program shall not be construed in any manner to preclude any State from adopting and enforcing any other air quality requirement (including any continuous emissions monitoring) that is not less stringent than, and does not alter, any requirement applicable to an affected unit or affected source under the Acid Rain Program; *provided* that such State requirement, if articulated in an operating permit, is in a portion of the operating permit separate from the

portion containing the Acid Rain Program requirements.

§ 72.6 Applicability.

(a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:

(1) A unit listed in Table 1 of § 73.10(a) of this chapter.

(2) An existing unit that is identified as qualifying for an allowance allocation under regulations implementing sections 403 and 405 of the Act and any other existing utility unit, except a unit under paragraph (b) of this section.

(3) A utility unit, except a unit under paragraph (b) of this section, that:

(i) Is a new unit; or

(ii) Did not serve a generator with a nameplate capacity greater than 25 MWe on November 15, 1990 but serves such a generator after November 15, 1990.

(b) The following types of units are not affected units subject to the requirements of the Acid Rain Program:

(1) A simple combustion turbine that commenced operation before November 15, 1990.

(2) Any unit that commenced commercial operation before November 15, 1990 and that did not, as of November 15, 1990, and does not currently, serve a generator with a nameplate capacity of greater than 25 MWe.

(3) Any unit that, during 1985, did not serve a generator that produced electricity for sale and that did not, as of November 15, 1990, and does not currently, serve a generator that produces electricity for sale.

(4) [Reserved: cogeneration units].

(5) [Reserved: qualifying facilities].

(6) [Reserved: new independent power production facilities].

(7) [Reserved: solid waste incinerators].

(8) A non-utility unit.

§ 72.7 New units exemption.

(a) *Applicability.* This section applies to any new utility unit that serves one or more generators with total nameplate capacity of 25 MWe or less and burns only fuels with a sulfur content of 0.05 percent or less by weight, as determined in accordance with paragraph (d)(2) of this section.

(b) *Petition for Written Exemption.* The designated representative, authorized in accordance with subpart B of this part, of a source that includes a unit under paragraph (a) of this section may petition the permitting authority for a written exemption, or to renew a written exemption, for the unit from certain requirements of the Acid Rain Program. The petition shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit.

(2) The nameplate capacity of each generator served by the unit.

(3) A list of all fuels currently burned by the unit and their percentage sulfur content by weight, determined in accordance with paragraph (a) of this section.

(4) A list of all fuels that are expected to be burned by the unit and their sulfur content by weight.

(5) The special provisions in paragraph (d) of this section.

(c) *Permitting Authority's Action.*

(1)(i) The permitting authority shall issue, for any unit meeting the requirements of paragraphs (a) and (b) of this section, a written exemption from the requirements of the Acid Rain Program except for the requirements specified in this section and §§ 72.1 through 72.6 and §§ 72.10 through 72.13; *provided* that no unit shall be exempted unless allowances, equal in number to, and with the same or earlier compliance use date as, all of those allocated under subpart B of part 73 of this chapter for any year for which the unit will be exempted, are deducted from the unit's Allowance Tracking System account.

(ii) The exemption shall take effect on January 1 of the year immediately following the earlier of the date on which the written exemption is issued subject to administrative appeal under part 78 of this chapter or is issued as a final agency action subject to judicial review, in accordance with paragraph (c)(2) of this section; *provided* that the owners and operators, and, to the extent applicable, the designated representative, shall comply with the requirements of the Acid Rain Program concerning all years for which the unit was not exempted, even if such requirements arise, or must be complied with, after the exemption takes effect. The exemption shall not be a defense against any violation of such requirements of the Acid Rain Program whether the violation occurs before or after the exemption takes effect.

(2) In considering and issuing or denying a written exemption under paragraph (c)(1) of this section, the permitting authority shall apply the procedures in subparts F and G of this part and part 70 of this chapter, as applicable, by:

(i) Treating the petition as an Acid Rain permit application under such provisions;

(ii) Issuing or denying a draft written exemption that is treated as the issuance or denial of a draft permit under such provisions; and

(iii) Where the Administrator is the permitting authority, issuing or denying a written exemption that is treated as the issuance or denial of a permit under subpart F of this part or, where a State is the permitting authority, issuing or denying a proposed written exemption that is treated as the issuance or denial of a proposed permit under subpart G of this part and part 70 of this chapter; *provided* that no provision under subparts F and G of this part and part 70 of this chapter concerning the content, effective date, or term of an Acid Rain permit shall apply to the written exemption or proposed written exemption under this section.

(3) A written exemption issued under this section shall have a term of 5 years from its effective date, except as provided in paragraph (d)(4) of this section.

(d) *Special Provisions.* (1) The owners and operators of each unit exempted under this section shall surrender allowances equal in number to, and with the same or an earlier compliance use date as, all of those allocated to the unit under subpart B of part 73 of this chapter for any year for which the unit is exempted and shall waive the right to receive any allowances to be allocated under subpart B of part 73 of this chapter for any year for which the unit is exempted.

(2) The owners and operators of each unit exempted under this section shall determine the sulfur content by weight of its fuel as follows:

(i) For petroleum or petroleum products that the unit burns starting on the first day on which the exemption takes effect until the exemption terminates, a sample of each delivery of such fuel shall be tested using ASTM methods ASTM D4057–88 and ASTM D129–91, ASTM D2622–92, or ASTM D4294–90 (all methods incorporated by reference under § 72.13 of this part.)

(ii) For natural gas that the unit burns starting on the first day on which the exemption takes effect until the exemption terminates, the sulfur content shall be assumed to be 0.05 per cent or less by weight.

(iii) For gaseous fuel (other than natural gas) that the unit burns starting on the first day on which the exemption takes effect until the exemption terminates, a sample of each delivery of such fuel shall be tested using ASTM methods ASTM D1072–90 and ASTM D1265–92 (incorporated by reference under § 72.13 of this part); *provided* that if the gaseous fuel is delivered by pipeline to the unit, a sample of the fuel shall be tested, at least once every

quarter in which the unit operates during any year for which the exemption is in effect, using ASTM method ASTM D1072–90 (incorporated by reference under § 72.13 of this part).

(3) The owners and operators of each unit exempted under this section shall retain at the source that includes the unit, the records of the results of the tests performed under paragraph (d)(2)(i) and (iii) of this section and a copy of the purchase agreements for the fuel under paragraph (d)(2) of this section, stating the sulfur content of such fuel. Such records and documents shall be retained for 5 years from the date they are created.

(4) On the earlier of the date the written exemption expires, the date a unit exempted under this section burns any fuel with a sulfur content in excess of 0.05 percent by weight (as determined in accordance with paragraph (d)(2) of this section), or 24 months prior to the date the unit first serves one or more generators with total nameplate capacity in excess of 25 MWe, the unit shall no longer be exempted under this section and shall be subject to all requirements of the Acid Rain Program, except that:

(i) Notwithstanding § 72.30 (b) and (c), the designated representative of the source that includes the unit shall submit a complete Acid Rain permit application on the later of January 1, 1998 or the date the unit is no longer exempted under this section.

(ii) For purposes of applying monitoring requirements under part 75 of this chapter, the unit shall be treated as a new unit that commenced commercial operation on the date the unit no longer meets the requirements of paragraph (a) of this section.

§ 72.8 Retired units exemption.

(a) *Applicability.* This section applies to any affected unit that is retired prior to the issuance (including renewal) of a Phase II Acid Rain permit for the unit as a final agency action.

(b) *Petition for Written Exemption.* (1) The designated representative, authorized in accordance with subpart B of this part, of a source that includes a unit under paragraph (a) of this section may petition the permitting authority for a written exemption, or to renew a written exemption, for the unit from certain requirements of this part.

(2) A petition under this section shall be submitted on or before:

(i) The deadline for submitting an Acid Rain permit application for Phase II; or

(ii) If the unit has a Phase II Acid Rain permit, the deadline for reapplying for such permit.

(3) The petition under this section shall include the following elements in a format prescribed by the Administrator:

(i) Identification of the unit.

(ii) The applicable deadline under paragraph (b)(2) of this section.

(iii) The actual or expected date of retirement of the unit.

(iv) The following statement: "I certify that this unit ['is' or 'will be', as applicable] permanently retired on the date specified in this petition and will not emit any sulfur dioxide or nitrogen oxides after such date."

(v) A description of any actions that have been or will be taken and provide the basis for the certification in paragraph (b)(3)(iv) of this section.

(iv) The special provisions in paragraph (d) of this section.

(c) *Permitting Authority's Action.* (1)(i) The permitting authority shall issue, for any unit meeting the requirements of paragraphs (a) and (b) of this section, a written exemption from the requirements of this part except for the requirements specified in this section and §§ 72.1 through 72.6 and §§ 72.10 through 72.13.

(ii) The exemption shall take effect on January 1 of the year following the earlier of the date on which the written exemption is issued subject to administrative appeal under part 78 of this chapter or is issued as a final agency action subject to judicial review, in accordance with paragraph (c)(2) of this section; *provided* that the owners and operators, and, to the extent applicable, the designated representative, shall comply with the requirements of this part concerning all years for which the unit was not exempted, even if such requirements arise or must be complied with after the exemption takes effect. The exemption shall not be a defense against any violation of such requirements of the Acid Rain Program whether the violation occurs before or after the exemption takes effect.

(2) In considering and issuing or denying a written exemption under paragraph (c)(1) of this section, the permitting authority shall apply the procedures in subparts F and G of this part and part 70 of this chapter, as applicable, by:

(i) Treating the petition as an Acid Rain permit application under such provisions;

(ii) Issuing or denying a draft written exemption that is treated as the issuance or denial of a proposed permit under such provisions; and

(iii) Where the Administrator is the permitting authority, issuing or denying a written exemption that is treated as a permit under subpart F of this part or, where a State is the permitting authority, issuing or denying a proposed written exemption that is treated as a proposed permit under subpart G of this part and part 70 of this chapter; *provided* that no provision under subparts F and G of this part and part 70 of this chapter concerning, the content, effective date, or term of an Acid Rain permit shall apply to the written exemption or proposed written exemption under this section.

(3) A written exemption issued under this section shall have a term of 5 years, except as provided in paragraph (d)(3) of this section.

(d) *Special Provisions.* (1) A unit exempted under this section shall not emit any sulfur dioxide and nitrogen dioxide starting on the date it is exempted.

(2) The owners and operators of a unit exempted under this section shall comply with monitoring requirements in accordance with part 75 of this chapter and will be allocated allowances in accordance with part 73 of this chapter.

(3) A unit exempted under this section shall not resume operation unless the designated representative of the source that includes the unit submits an Acid Rain permit application for the unit not less than 24 months prior to the later of January 1, 2000 or the date the unit is to resume operation. On the earlier of the date the written exemption expires or the date an Acid Rain permit application is submitted or is required to be submitted under this paragraph, the unit shall no longer be exempted under this section and shall be subject to all requirements of this part.

§ 72.9 Standard requirements.

(a) *Permit Requirements.* (1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under this part in accordance with the deadlines specified in § 72.30;

(ii) Submit in a timely manner a complete reduced utilization plan if required under § 72.43; and

(iii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

(b) *Monitoring Requirements.* (1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in part 75 of this chapter and section 407 of the Act and regulations implementing section 407 of the Act.

(2) The emissions measurements recorded and reported in accordance with part 75 of this chapter and section 407 of the Act and regulations implementing section 407 of the Act shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of part 75 of this chapter and regulations implementing section 407 of the Act shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

(c) *Sulfur Dioxide Requirements.* (1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under § 73.34(c) of this chapter) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

(ii) Comply with the applicable Acid Rain emissions limitation for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (c)(1) of this section as follows:

(i) Starting January 1, 1995, an affected unit under § 72.6(a)(1);

(ii) Starting on or after January 1, 1995 in accordance with §§ 72.41 and 72.43, an affected unit under § 72.6(a) (2) or (3) that is a substitution or compensating unit;

(iii) Starting January 1, 2000, an affected unit under § 72.6(a)(2) that is not a substitution or compensating unit; or

(iv) Starting on the later of January 1, 2000 or the deadline for monitor certification under part 75 of this chapter, an affected unit under § 72.6(a)(3) that is not a substitution or compensating unit.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted, in order to comply with the requirements under paragraph (c)(1)(i) of this section, prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under §§ 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

(d) *Nitrogen Oxides Requirements.* The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

(e) *Excess Emissions Requirements.* (1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under part 77 of this chapter.

(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall:

(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by part 77 of this chapter; and

(ii) Comply with the terms of an approved offset plan, as required by part 77 of this chapter.

(f) *Recordkeeping and Reporting Requirements.* (1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority.

(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with § 72.24; *provided* that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative.

(ii) All emissions monitoring information, in accordance with part 75 of this chapter.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program.

(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under subpart I of this part and part 75 of this chapter.

(g) *Liability.* (1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under § 72.7 or § 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as

provided under § 72.41 (substitution plans), § 72.42 (Phase I extension plans), § 72.43 (reduced utilization plans), § 72.44 (Phase II repowering extension plans), and section 407 of the Act and regulations implementing section 407 of the Act, and except with regard to the requirements applicable to units with a common stack under part 75 of this chapter (including §§ 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of this part, parts 73, 75, 77, and 78 of this chapter, and regulations implementing sections 407 and 410 of the Act by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

(h) *Effect on Other Authorities.* No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under § § 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans.

(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act.

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law.

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

§ 72.10 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under the Acid Rain Program shall be governed by part 2 of this chapter.

§ 72.11 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the Acid Rain Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the Acid Rain Program, to begin before the occurrence of an act or event shall be computed so that the period ends on the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the Acid Rain Program, falls on a weekend or a federal holiday, the time period shall be extended to the next business day.

(d) Whenever a party or interested person has the right, or is required, to act under the Acid Rain Program within a prescribed time period after service of notice or other document upon him or her by mail, 3 days shall be added to the prescribed time.

§ 72.12 Administrative Appeals.

The procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§ 72.13 Incorporation by reference.

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they existed on the date of approval, and a notice of any change in these materials will be published in the **Federal Register**. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Office of the Federal Register, 800 N. Capitol Street, NW., Washington, DC, at the Public Information Reference Unit of the U.S. EPA, 401 M Street SW, Washington, DC and at the Library (MD–35), U.S. EPA, Research Triangle Park, North Carolina.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; and the University Microfilms International 300 North Zeeb Road, Ann Arbor, Michigan 48106.

(1) ASTM D129–91, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), for § 72.7 of this chapter.

(2) ASTM D388–92, Standard Classification of Coals by Rank for § 72.2 of this chapter.

(3) ASTM D396–90a, Standard Specification for Fuel Oils, for § 72.2 of this chapter.

(4) ASTM D975–91, Standard Specification for Diesel Fuel Oils, for § 72.2 of this chapter.

(5) ASTMD1072–90, Standard Test Method for Total Sulfur in Fuel Gases, for § 72.7 of this chapter.

(6) ASTMD1265–92, Standard Practice for Sampling Liquified Petroleum (LP) Gases (Manual Method), for § 72.7 of this chapter.

(7) ASTM D2622–92, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry, for § 72.7 of this chapter.

(8) ASTM D 4057–88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, for § 72.7 of this chapter.

(9) ASTM D4294–90, Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy, for § 72.7 of this chapter.

Subpart B—Designated Representative

§ 72.20 Authorization and responsibilities of the designated representative.

(a) Except as provided under § 72.22, each affected source, including all affected units at the source, shall have one and only one designated representative, with regard to all matters under the Acid Rain Program concerning the source or any affected unit at the source.

(b) Upon receipt by the Administrator of a complete certificate of representation, the designated representative of the source shall represent and, by his or her actions, inactions, or submissions, legally bind each owner and operator of the affected source represented and each affected unit at the source in all matters pertaining to the Acid Rain Program, not withstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any order issued to the designated representative by the Administrator, the permitting authority, or a court.

(c) The designated representative shall be selected and act in accordance with the certifications set forth in § 72.24(a) (4), (5), (7), and (9).

(d) No Acid Rain permit shall be issued to an affected source, nor shall any allowance transfer be recorded for an Allowance Tracking System account of an affected unit at a source, until the Administrator has received a complete

certificate of representation for the designated representative of the source and the affected units at the source.

§ 72.21 Submissions.

(a) Each submission under the Acid Rain Program shall be submitted, signed, and certified by the designated representative for all sources on behalf of which the submission is made.

(b) In each submission under the Acid Rain Program, the designated representative shall certify, by his or her signature:

(1) The following statement, which shall be included verbatim in such submission: "I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made."

(2) The following statement, which shall be included verbatim in such submission: "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) The Administrator and the permitting authority shall accept or act on a submission made on behalf of owners or operators of an affected source and an affected unit only if the submission has been made, signed, and certified in accordance with paragraphs (a) and (b) of this section.

(d) (1) The designated representative of a source shall serve notice on each owner and operator of the source and of an affected unit at the source:

(i) By the date of submission, of any Acid Rain Program submissions by the designated representative and

(ii) Within 10 business days of receipt of a determination, of any written determination by the Administrator or the permitting authority,

(iii) Provided that the submission or determination covers the source or the unit.

(2) The designated representative of a source shall provide each owner and operator of an affected unit at the source a copy of any submission or determination under paragraph (d)(1) of this section, unless the owner or operator expressly waives the right to receive such a copy.

(e) The provisions of this section shall apply to a submission made under parts 73, 75, 77, and 78 of this chapter and under regulations implementing sections 407 and 410 of the Act only if it is made or signed, or required to be made or signed in accordance with parts 73, 75, 77, and 78 of this chapter and regulations implementing sections 407 and 410 of the Act, by:

(i) The designated representative; or

(ii) The authorized account representative or alternate authorized account representative of a unit account.

§ 72.22 Alternate designated representative.

(a) The certificate of representation may designate one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation that meets the requirements of § 72.24 (including those applicable to the alternate designated representative), any action, representation, or failure to act by the alternate designated representative shall be deemed to be an action, representation, or failure to act by the designated representative.

(c) In the event of a conflict, any action taken by the designated representative shall take precedence over any action taken by the alternate designated representative if, in the Administrator's judgement, the actions are concurrent and conflicting.

(d) Except in this section, § 72.23, and § 72.24, whenever the term "designated representative" is used under the Acid Rain Program, the term shall be construed to include the alternate designated representative.

§ 72.23 Changing the designated representative, alternate designated representative; changes in the owners and operators.

(a) *Changing the designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation. Notwithstanding any such change, all submissions, actions, and inactions by the previous designated representative prior to the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and on the owners and operators of the source represented and the affected units at the source.

(b) *Changing the alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation. Notwithstanding any such change, all submissions, actions, and inactions by the previous alternate designated representative prior to the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative and on the owners and operators of the source represented and the affected units at the source.

(c) *Changes in the owners and operators.* (1) In the event a new owner or operator of an affected source or an affected unit is not included in the list of owners and operators submitted in the certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the submissions, actions, and inactions of the designated representative and any alternative designated representative of the source or unit, and the decisions, actions, and inactions of the Administrator and permitting authority, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of an affected unit, including the addition of a new owner or operator, the designated representative or any alternative designated representative shall submit a revision to the certificate of representation amending the list of owners and operators to include the change.

§ 72.24 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the affected source and each affected unit at the source for which the certificate of representation is submitted.

(2) The name, address, and telephone and facsimile numbers of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the affected source and of each affected unit at the source and all State or local utility regulatory authorities with jurisdiction over each owner.

(4) The following statement: "I certify that I was selected as the 'designated representative' or 'alternate designated representative,' as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source."

(5) The following statement: "I certify that I have given notice of the agreement, selecting me as the 'designated representative' or 'alternate designated representative,' as applicable for the affected source and each affected unit at the source identified in this certificate of representation, daily for a period of one week in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice."

(6) The following statement: "I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions."

(7) The following statement: "I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as 'designated representative' or 'alternate designated representative', as applicable."

(8) The following statement: "I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit."

(9) The following statement: "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

(i) "I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and

(ii) "Allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract."

(10) If there is an alternate designated representative, the following statement: "The agreement by which I was selected as the alternate designated representative includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative."

(11) The signature of the designated representative and any alternate designated representative and the date signed.

(b) Unless otherwise required by the Administrator or the permitting authority, documents of agreement or notice referred to in the certificate of representation shall not be submitted to the Administrator or the permitting authority. Neither the Administrator nor the permitting authority shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 72.25 Objections.

(a) Once a complete certificate of representation has been submitted in accordance with § 72.24, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate is submitted to the Administrator.

(b) Except as provided in § 72.23, no objection or other communication submitted to the Administrator or the permitting authority concerning the authorization, or any submission, action or inaction, of the designated representative shall affect any submission, action, or inaction of the designated representative, or the finality of any decision by the Administrator or permitting authority, under the Acid Rain Program. In the event of such communication, the Administrator and the permitting authority are not required to stay any allowance transfer, any submission, or the effect of any action or inaction under the Acid Rain Program.

(c) Neither the Administrator nor any permitting authority will adjudicate any private legal dispute concerning the authorization or any submission, action, or inaction of any designated representative, including private legal disputes concerning the proceeds of allowance transfers.

Subpart C—Acid Rain Permit Applications

§ 72.30 Requirement to apply.

(a) *Duty to apply.* The designated representative of any source with an affected unit shall submit a complete Acid Rain permit application by the applicable deadline in paragraphs (b) and (c) of this section, and the owners and operators of such source and any affected unit at the source shall not operate the source or unit without a permit that states its Acid Rain program requirements.

(b) *Deadlines.* (1) *Phase I.* (i) The designated representative shall submit a complete Acid Rain permit application governing an affected unit during Phase I to the Administrator on or before February 15, 1993 for:

(A) Any source with such a unit under § 72.6(a)(1); and

(B) Any source with such a unit under § 72.6(a) (2) or (3) that is designated a substitution or compensating unit in a substitution plan or reduced utilization plan submitted to the Administrator for approval or conditional approval.

(ii) Notwithstanding paragraph (b)(1)(i) of this section, if a unit at a source not previously permitted is designated a substitution or compensating unit in a submission requesting revision of an existing Acid Rain permit, the designated representative of the unit shall submit a complete Acid Rain permit application on the date that the submission requesting the revision is made.

(2) *Phase II.* For any source with an existing unit under § 72.6(a)(2), the designated representative shall submit a complete Acid Rain permit application governing such unit during Phase II to the permitting authority on or before January 1, 1996.

(ii) For any source with a new unit under § 72.6(a)(3)(i), the designated representative shall submit a complete Acid Rain permit application governing such unit to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation.

(iii) For any source with a unit under § 72.6(a)(3)(ii), the designated representative shall submit a complete Acid Rain permit application governing such unit to the permitting authority at least 24 months before the later of January 1,2000 or the date on which the unit begins to serve a generator with a nameplate capacity greater than 25 MWe.

(3) *Acid Rain Compliance Option Deadlines.* The deadlines for applying for approval of any Acid Rain compliance options shall be the

deadlines specified in the relevant section of subpart D of this part and in section 407 of the Act and regulations implementing section 407 of the Act.

(c) *Duty to Reapply.* The designated representative shall submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted.

(d) The original and three copies of all permit applications for Phase I and where the Administrator is the permitting authority, for Phase II, shall be submitted to the EPA Regional Office for the Region where the affected source is located. The original and three copies of all permit applications for Phase II, where the Administrator is not the permitting authority, shall be submitted to the State permitting authority for the State where the affected source is located.

§ 72.31 Information requirements for Acid Rain permit applications.

A complete Acid Rain permit application shall include following elements in a format prescribed by the Administrator:

(a) Identification of the affected source for which the permit application is submitted;

(b) Identification of each Phase I unit at the source for which the permit application is submitted for Phase I or each Phase II unit at the source for which the permit application is submitted for Phase II;

(c) A complete compliance plan for each unit, in accordance with subpart D of this part;

(d) The standard requirements under § 72.9; and

(e) If the Acid Rain permit application is for Phase II and the unit is a new unit, the date that the unit has commenced or will commence operation and the deadline for monitor certification.

§ 72.32 Permit application shield and binding effect of permit application.

(a) Once a designated representative submits a timely and complete Acid Rain permit application, the owners and operators of the affected source and the affected units covered by the permit application shall be deemed in compliance with the requirement to have an Acid Rain permit under § 72.9(a)(2) and § 72.30(a); *provided* that any delay in issuing an Acid Rain permit is not caused by the failure of the designated representative to submit in a complete and timely fashion supplemental information, as required by the permitting authority, necessary to issue a permit.

(b) Prior to the earlier of the date on which an Acid Rain permit is issued subject to administrative appeal under part 78 of this chapter or is issued as a final agency action subject to judicial review, an affected unit governed by and operated in accordance with the terms and requirements of a timely and complete Acid Rain permit application shall be deemed to be operating in compliance with the Acid Rain Program.

(c) A complete Acid Rain permit application shall be binding on the owners and operators and the designated representative of the affected source and the affected units covered by the permit application and shall be enforceable as an Acid Rain permit from the date of submission of the permit application until the issuance or denial of an Acid Rain permit covering the units and subject to administrative appeal, where the Administrator is the permitting authority, or the issuance or denial of such permit as a final agency action subject to judicial review, where the State is the permitting authority.

§ 72.33 Identification of dispatch system.

(a) Every Phase I unit shall be treated as part of a dispatch system for purposes of § 72.92 in accordance with this section.

(b)(1) The designated representatives of all affected units in a group of all units and generators that are interconnected and centrally dispatched and that are included in the same utility system, holding company, or power pool, may jointly submit to the Administrator a complete identification of dispatch system.

(2) Except as provided in paragraphs (d) and (f) of this section, each Phase I unit may be listed in only one identification of dispatch system.

(3) Any identification of dispatch system must be filed by January 30 of the first year for which the identification is to be in effect.

(c) A complete identification of dispatch system shall include the following elements in a format prescribed by the Administrator:

(1) The name of the dispatch system.

(2) The list of all units and sulfur-free generators in the dispatch system.

(3) The first calendar year for which the identification is to be in effect.

(4) The following statement: "I certify that the units listed herein are and will continue to be interconnected and centrally dispatched, and will be treated as a dispatch system under § 72.92, during the period that this identification of dispatch system is in effect. During such period, all information concerning these units and contained in any submissions under § 72.92 by me and the other designated representatives of these units shall be consistent and shall conform with the data in the dispatch system data reports under § 72.92(b)(2). I understand that if this requirement is not met, then the Administrator will reject all such submissions and treat each unit's utility system as its dispatch system. In such an event, I will make the submissions required under § 72.92 (including a dispatch system data report), treating as the dispatch system the utility system of each unit that I represent."

(5) The signatures of the designated representative for each affected unit in the dispatch system.

(d) In order to change a unit's current dispatch system, complete identifications of dispatch system shall be submitted for the unit's current dispatch system and the unit's new dispatch system, reflecting the change.

(e)(1) Any Phase I unit that is not listed in a complete identification of dispatch shall treat its utility system as its dispatch system.

(2) During the period that the identification of dispatch system is in effect, all information that concerns the units in a given dispatch system and that is contained in any submissions under § 72.92 by designated representatives of these units shall be consistent and shall conform with the data in the dispatch system data reports under § 72.92(b)(2). If this requirement is not met, the Administrator will reject all such submissions, and the designated representatives shall make the submissions under § 72.92 (including the dispatch system data report) treating the utility system of each unit as its dispatch system.

(f)(1) Notwithstanding paragraph (e)(1) of this section or any submission of an identification of dispatch system under paragraphs (b), (c), or (d) of this section, the designated representative of a Phase I unit with two or more owners may petition the Administrator to treat, as the dispatch system for an owner's portion of the unit, the dispatch system of another unit. For purposes of paragraphs (f)(1) through (6) of this section, the owner's portion of the unit shall equal the percentage of that owner's ownership interest in the capacity of the unit.

(2) The petition shall be submitted by January 30 of the first year for which the dispatch system proposed in the petition will take effect, if approved.

The petition shall include the following elements:

(i) The owner's portion of the unit and the other owners' portion(s) of the unit and a demonstration that the sum of all owners' portions of the unit equals 100 percent;

(ii) Documentation demonstrating that the owner's portion specified in the petition equals its ownership interest in the capacity of the unit;

(iii) The name of the proposed dispatch system and documentation demonstrating that the owner's portion of the unit, along with the other units in the proposed dispatch system, are a group of all units and generators that are interconnected and centrally dispatched and that are included in the same utility system, holding company, or power pool.

(iv) The following statement, signed by the designated representatives of all units in the proposed dispatch system: "I certify that the units in the dispatch system proposed in this petition are and will continue to be interconnected and centrally dispatched, and will be treated as a dispatch system under § 72.92, during the period that this petition, as approved, is in effect."

(v) The following statement, signed by the designated representatives of all units in all dispatch systems that will include any portion of the unit if the petition is approved: "During the period that this petition, if approved, is in effect, all information that concerns the units in any dispatch system including any portion of the unit apportioned under the petition and that is contained in any submissions under §§ 72.91 and 72.92 by me and the other designated representatives of these units shall be consistent and shall conform to the data in the dispatch system data reports under § 72.92(b)(2). I am aware of, and will comply with, the requirements imposed under 40 CFR 72.33(f) (4) and (5)."

(3) The Administrator will approve in whole, in part, or with changes or conditions, or deny the petition within 90 days of receipt of the petition. The Administrator will treat the petition, as changed or conditioned upon approval, as amending any identification of dispatch system that is submitted prior to the approval and includes any portion of the unit for which the petition is approved.

(4) The designated representative for the unit for which a petition is approved and the designated representatives of all other units included in all dispatch systems that include any portion of the unit shall submit all annual compliance certification reports, dispatch system data reports, and other reports required under §§ 72.91 and 72.92 treating, as a separate unit, each portion of the unit for which a petition is approved under paragraph (f)(3) of this section and the remaining portion of the unit. The reports shall include all required calculations and demonstrations, treating each such portion of the unit as a separate unit; provided that plan reductions shall be treated in a manner to be determined by the Administrator on a case-by-case basis. The designated representatives shall demonstrate that the data in all the reports under §§ 72.91 and 72.92 has been properly attributed to or apportioned among the owners' portions of the unit and the dispatch systems and that there is no undercounting or double-counting with regard to such data.

(5) In the event that the designated representatives fail to make all the proper attributions, apportionments, calculations, and demonstrations, the Administrator may require that:

(i) All portions of the unit be treated as part of the dispatch system of the unit in accordance with paragraph (e)(1) of this paragraph and any identification of dispatch system submitted under paragraph (b) of this section; and

(ii) The designated representatives make all submissions under §§ 72.91 and 72.92 (including the dispatch system data report) in accordance with paragraph (e)(1) of this paragraph and any identification of dispatch system submitted under paragraph (b) of this section.

(6) Except as expressly provided in paragraphs (f) (1) through (5) of this section or the Administrator's approval of the petition, all provisions of the Acid Rain Program applicable to an affected source or an affected unit shall apply to the entire unit regardless of whether a petition has been submitted or approved, or reports have been submitted, under such paragraphs. Approval of a petition under such paragraphs shall not constitute a determination of the percentage ownership in a unit under any other provision of the Acid Rain Program.

Subpart D—Acid Rain Compliance Plan and Compliance Options

§ 72.40 General.

(a) For each affected unit included in an Acid Rain permit application, a complete compliance plan shall:

(1) For sulfur dioxide emissions, certify that, as of the allowance transfer deadline, the designated representative will hold allowances in the unit's compliance subaccount (after deductions under § 73.34(c) of this chapter) not less than the total annual emissions of sulfur dioxide from the unit. The compliance plan may also specify, in accordance with this subpart, one or more of the Acid Rain compliance options.

(2) For nitrogen oxides emissions, certify that the unit will comply with the applicable limitation established by regulations implementing section 407 of the Act or shall specify one or more Acid Rain compliance options, in accordance with section 407 of the Act and regulations implementing section 407.

(b) *Multi-unit compliance options.* (1) A plan for a compliance option, under § 72.41, 72.42, 72.43, or 72.44 of this part or section 407 of the Act and regulations implementing section 407, that includes units at more than one affected source shall be complete only if:

(i) Such plan is signed and certified by the designated representative for each source with an affected unit governed by such plan; and

(ii) A complete permit application is submitted covering each unit governed by such plan.

(2) A permitting authority's approval of a plan under paragraph (b)(1) of this section that includes units in more than one State shall be final only after every permitting authority with jurisdiction over any such unit has approved the plan with the same modifications or conditions, if any.

(c) *Conditional Approval.* In the compliance plan, the designated representative of an affected unit may propose, in accordance with this subpart, any Acid Rain compliance option for conditional approval, except a Phase I extension plan; *provided* that an Acid Rain compliance option under section 407 of the Act may be conditionally proposed only to the extent provided in regulations implementing section 407 of the Act.

(1) To activate a conditionally-approved Acid Rain compliance option, the designated representative shall notify the permitting authority in writing that the conditionally-approved compliance option will actually be pursued beginning January 1 of a specified year. If the conditionally approved compliance option includes a plan described in paragraph (b)(1) of this section, the designated representative of each source governed by the plan shall sign and certify the notification. Such notification shall be subject to the limitations on activation under subpart D of this part and regulations implementing section 407 of the Act.

(2) The notification under paragraph (c)(1) of this section shall specify the

first calendar year and the last calendar year for which the conditionally approved Acid Rain compliance option is to be activated. A conditionally approved compliance option shall be activated, if at all, before the date of any enforceable milestone applicable to the compliance option. The date of activation of the compliance option shall not be a defense against failure to meet the requirements applicable to that compliance option during each calendar year for which the compliance option is activated.

(3) Upon submission of a notification meeting the requirements of paragraphs (c) (1) and (2) of this section, the conditionally-approved Acid Rain compliance option becomes binding on the owners and operators and the designated representative of any unit governed by the conditionally-approved compliance option.

(4) A notification meeting the requirements of paragraphs (c) (1) and (2) of this section will revise the unit's permit in accordance with § 72.83 (administrative permit amendment).

(d) *Termination of Compliance Option.* (1) The designated representative for a unit may terminate an Acid Rain compliance option by notifying the permitting authority in writing that an approved compliance option will be terminated beginning January 1 of a specified year. If the compliance option includes a plan described in paragraph (b)(1) of this section, the designated representative for each source governed by the plan shall sign and certify the notification. Such notification shall be subject to the limitations on termination under subpart D of this part and regulations implementing section 407 of the Act.

(2) The notification under paragraph (d)(1) of this section shall specify the calendar year for which the termination will take effect.

(3) Upon submission of a notification meeting the requirements of paragraphs (d) (1) and (2) of this section, the termination becomes binding on the owners and operators and the designated representative of any unit governed by the Acid Rain compliance option to be terminated.

(4) A notification meeting the requirements of paragraphs (d) (1) and (2) of this section will revise the unit's permit in accordance with § 72.83 (administrative permit amendment).

§ 72.41 Phase I substitution plans.

(a) *Applicability.* This section shall apply during Phase I to the designated representative of:

(1) Any unit listed in Table 1 of § 73.10(a) of this chapter; and

(2) Any other existing utility unit that is an affected unit under this part, provided that this section shall not apply to a unit under section 410 of the Act.

(b)(1) The designated representative may include, in the Acid Rain permit application for a unit under paragraph (a)(1) of this section, a substitution plan under which one or more units under paragraph (a)(2) of this section are designated as substitution units, provided that:

(i) Any unit under paragraph (a)(2) of this section has the same owner or operator (which includes, for purposes of this section, a designated representative) as the unit under paragraph (a)(1) of this section; and

(ii) In accordance with paragraph (c)(3) of this section, the emissions reductions achieved under the plan shall be the same or greater than would have been achieved by all units governed by the plan without such plan.

(2) The designated representative of each source with a unit designated as a substitution unit in any plan submitted under paragraph (b)(1) of this section shall incorporate in the permit application each such plan.

(3) The designated representative may submit a substitution plan not later than 90 days, or a notification to activate a conditionally approved plan in accordance with § 72.40(c) not later than 60 days, before the allowance transfer deadline applicable to the first year for which the plan is to take effect.

(c) *Contents of a Substitution Plan.* A complete substitution plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each unit under paragraph (a)(1) of this section and each substitution unit to be governed by the substitution plan. A unit shall not be a substitution unit in more than one substitution plan.

(2) Except where the designated representative requests conditional approval of the plan, the first calendar year and, if known, the last calendar year in which the substitution plan is to be in effect. Unless the designated representative specifies an earlier calendar year, the last calendar year will be deemed to be 1999.

(3) Calculations to demonstrate that the total emissions reductions achieved under the substitution plan will be equal to or greater than the total emissions reductions that would have been achieved without the plan, as follows:

(i) for each substitution unit:

(A) the unit's baseline.

(B) the lesser of the unit's 1985 actual SO_2 emissions rate or 1985 allowable SO_2 emissions rate.

(C) the product of the baseline in paragraph (c)(3)(i)(A) of this section and the emissions rate in paragraph (c)(3)(i)(B) of this section, divided by 2000 lbs/ton.

(ii) The sum of the amounts in paragraph (c)(3)(i)(C) of this section for all substitution units to be governed by the plan. This sum is the total number of allowances available each year under the substitution plan.

(4) Distribution of substitution allowances.

(i) A statement that the allowances in paragraph (c)(3)(ii) of this section are not to be distributed to any units under paragraph (a)(1) of this section that are to be governed by the plan; or

(ii) A list showing any annual distribution of the allowances in paragraph (c)(3)(ii) of this section from a substitution unit to the unit under paragraph (a)(1) of this section to be governed by the plan. The total number of such allowances allocated among such units each year may not exceed the number calculated under paragraph (c)(3)(ii) of this section.

(5) The special provisions in paragraph (e) of this section.

(d) *Administrator's Action.* (1) If the Administrator approves a substitution plan, he or she will allocate allowances to the Allowance Tracking System accounts of the units under paragraph (a)(1) of this section and substitution units, as provided in the approved plan, upon issuance of an Acid Rain permit containing the plan, except that if the substitution plan is conditionally approved, the allowances will be allocated upon revision of the permit to activate the plan.

(2) In no event shall allowances be allocated, under paragraph (d)(1) of this section, for any year in excess of the amount in paragraph (c)(3)(ii) of this section, as adjusted by the Administrator in approving the plan.

(e) *Special Provisions.*

(1) *Emissions Limitations.* (i) Each substitution unit governed by an approved substitution plan shall become a Phase I unit from January 1 of the year for which the plan takes effect until January 1 of the year for which the plan is no longer in effect or is terminated.

(ii) Each unit under paragraph (a)(1) of this section, and each substitution unit, governed by an approved substitution plan shall be subject to the Acid Rain emissions limitations for nitrogen oxides in accordance with section 407 of the Act and regulations implementing section 407 of the Act.

(2) *Liability.* The owners and operators of a unit governed by an approved substitution plan shall be liable for any violation of the plan or this section at that unit or any other unit that is the first unit's substitution unit or for which the first unit is a substitution unit under the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and section 411 of the Act.

(3) *Termination.* (i) A substitution plan shall be in effect only in Phase I for the calendar years specified in the plan or until the calendar year for which a termination of the plan takes effect, provided that no substitution plan shall be terminated, and no unit shall be de-designated as a substitution unit, before the end of Phase I if the substitution unit serves as a control unit under a Phase I extension plan.

(ii) To terminate a substitution plan for a given calendar year prior to the last year for which the plan was approved:

(A) A notification to terminate in accordance with § 72.40(d) shall be submitted no later than 60 days before the allowance transfer deadline applicable to the given year; and

(B) In the notification to terminate, the designated representative of each unit governed by the plan shall state that he or she surrenders for deduction from the unit's Allowance Tracking System account allowances equal in number to, and with the same or an earlier compliance use date as, those allocated under paragraph (d)(1) of this section for all calendar years for which the plan is to be terminated. The designated representative may identify the serial numbers of the allowances to be deducted. In the absence of such identification, allowances will be deducted on a first-in, first-out basis under § 73.35(c)(2) of this chapter.

(iii) If the requirements of paragraph (e)(2)(ii) of this section are met and upon revision of the permit to terminate the substitution plan, the Administrator will deduct the allowances specified in paragraph (e)(2)(ii)(B) of this section. No substitution plan shall be terminated, and no unit shall be de-designated as a Phase I unit, unless such deduction is made.

(iv) Change of owner or operator. If there is a change in the owners or operators (which includes for purposes of this section the designated representative) of any unit governed by an approved substitution plan and the requirement under paragraph (b)(1)(i) of this section is no longer met, then the designated representatives of the units governed by the plan shall terminate the plan as of January 1 of the calendar year during which the change was made. if the designated representatives fail to terminate the plan, the Administrator, on his own motion, shall terminate the plan and deduct the allowances required to be surrendered under paragraph (e)(2)(ii) of this section.

§ 72.42 Phase I extension plans.

(a) *Applicability.* (1) This section shall apply to any designated representative seeking a 2-year extension of the deadline for meeting Phase I sulfur dioxide emissions reduction requirements at any of the following types of units by applying for allowances from the Phase I extension reserve:

(i) a unit listed in Table 1 of § 73.10(a) of this chapter;

(ii) a unit designated as a substitution unit in accordance with § 72.41; or

(iii) a unit designated as a compensating unit in accordance with § 72.43, except a compensating unit that is a new unit.

(2) A unit for which a Phase I extension is sought shall be either:

(i) A control unit, which shall be a unit under paragraph (a)(1) of this section and at which qualifying Phase I technology shall commence operation on or after November 15, 1990 but not later than December 31, 1996; or

(ii) A transfer unit, which shall be a unit under paragraph (a)(1)(i) of this section and whose Phase I emissions reduction obligation shall be transferred in whole or in part to one or more control units.

(3) A Phase I extension does not exempt the owner or operator for any unit governed by the Phase I extension plan from the requirement to comply with such unit's Acid Rain emissions limitations for sulfur dioxide.

(b) To apply for a Phase I extension:

(1) The designated representative for each source with a control unit may submit an early ranking application for a Phase I extension plan in person, beginning on the 40th day after publication of this subpart in the **Federal Register**, between the hours of 9 a.m. and 5 p.m. Eastern Standard Time at Acid Rain Division, Attn: Early Ranking, U.S. Environmental Protection Agency, 501 3rd Street NW., 4th floor, Washington, DC; or send the application by regular mail, certified mail, or overnight delivery service to Acid Rain Division, Attn: Early Ranking, U.S. Environmental Protection Agency, 6204 J, 401 M Street, SW., Washington, DC 20460.

(2) By February 15, 1993: (i) The designated representative for each source with a control unit shall submit a Phase I extension plan as a part of the Acid Rain permit application for the source, and

(ii) The designated representative for each source with a unit designated as a transfer unit in any plan submitted under paragraph (b)(2)(i) of this section shall incorporate in the Acid Rain permit application each such plan.

(c) *Contents of Early Ranking Application.* A complete early ranking application shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each control unit. All control units in an application must be located at the same source. If the control unit is not a unit under paragraph (a)(1)(i) of this section, a substitution plan or a reduced utilization plan governing the unit shall be submitted by the deadline for submitting a Phase I permit application.

(2) Identification of each transfer unit. A unit shall not be a transfer unit in more than one early ranking application.

(3) For each control and transfer unit, the total tonnage of sulfur dioxide emitted in 1988 plus the total tonnage of sulfur dioxide emitted in 1989, divided by 2. The 1988 and 1989 tonnage figures shall be consistent with the data filed on EIA form 767 for those years and the conversion methodology specified in Appendix B of this part.

(4) For each control and transfer unit:

(i) The projected annual utilization (in mmBtu) for 1995 multiplied by the projected uncontrolled emissions rate (i.e., the emissions rate in the absence of title IV of the Act) for 1995 (in lbs/mmBtu), divided by 2000 lbs/ton.

(ii) The projected annual utilization (in mmBtu) for 1996 multiplied by the projected uncontrolled emissions rate (i.e., the emissions rate in the absence of title IV of the Act) for 1996 (in lbs/mmBtu), divided by 2000 lbs/ton.

(5) For each control and transfer unit, the number of Phase I extension reserve allowances requested for 1995 and for 1996, not to exceed the difference between:

(i) The lesser of the value for the unit under paragraph (c)(3) of this section and the value for the unit for that year under paragraph (c)(4) of this section, and

(ii) Each unit's baseline multiplied by 2.5 lb/mmBtu, divided by 2000 lbs/ton.

(6) Documentation that the annual emissions reduction obligations transferred from all transfer units to all control units do not exceed those authorized under this section, as follows:

(i) For each control unit, the difference, calculated separately for 1995 and 1996, between:

(A) The control unit's allowance allocation in Table 1 of § 73.10(2) of this chapter, the allocation under § 72.41 if the control unit is a substitution unit, or the allocation under § 72.43 if the control unit is a compensating unit; and

(B) The projected emissions resulting from 90% control after installing the qualifying Phase I technology, i.e., 10% of the projected uncontrolled emissions for the control unit for the year in accordance with paragraph (c)(4) of this section.

(ii) The sum, by year, of the results under paragraph (c)(6)(i) of this section for all control units.

(iii) The sum, by year, of Phase I extension reserve allowances requested for all transfer units.

(iv) A showing that, for each year, the sum under paragraph (c)(6)(ii) of this section is greater than or equal to the sum under paragraph (c)(6)(iii) of this section.

(7) For each control and transfer unit, the projected controlled emissions for 1997, for 1998, and for 1999 calculated as follows:

Projected annual utilization (in mmBtu) multiplied by the projected controlled emission rate (in lbs/mmBtu), divided by 2000 lbs/ton.[1]

(8) For each control unit, the number of Phase I extension reserve allowances requested for 1997, for 1998, and for 1999, calculated as follows:

The unit's baseline multiplied by 1.2 lbs/mmBtu and divided by 2000 lbs/ton, minus the projected controlled emissions (in tons/yr) under paragraph (c)(7) of this section for the given year.

(9) The total of Phase I extension reserve allowances requested for all units in the plan for 1995 through 1999.

(10) With regard to each executed contract for the design engineering and construction of qualifying Phase I technology at each control unit governed by the early ranking application, either a copy of the contract or a certification that the contract is on site at the source and will be submitted to the Administrator upon written request. The contract or contracts may be contingent on the Administrator approving the Phase I extension plan.

(11) For each contract for which a certification is submitted under paragraph (c)(10) of this section, a binding letter agreement, signed and dated by each party and specifying:

(i) The type of qualifying Phase I technology to which the contract applies;

(ii) The parties to the contract;

(iii) The date each party executed the contracts;

(iv) The unit to which the contract applies;

(v) A brief list identifying each provision of the contract;

(vi) Any dates to which the parties agree, including construction completion date; and

(vii) The total dollar amount of the contract.

(12) A vendor certification of the sulfur dioxide removal efficiency guaranteed to be achievable by the qualifying Phase I technology for the type and range of fossil fuels (before any treatment prior to combustion) that will be used at the control unit; *provided* that a vendor certification shall not be a defense against a control unit's failure to achieve 90% control of sulfur dioxide.

(13) The date (not later than December 31, 1996) on which the owners and operators plan to commence operation of the qualifying Phase I technology.

(14) The special provisions of paragraph (f) of this section.

(d) *Contents of Phase I Extension Plan.* A complete Phase I extension plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each unit in the plan.

(2)(i) A statement that the elements in the Phase I extension plan are identical to those in the previously submitted early ranking application for the plan and that such early ranking application is incorporated by reference; or

(ii) All elements that are different from those in the previously submitted early ranking application for the plan and a statement that the early ranking application is incorporated by reference as modified by the newly submitted elements; *provided* that the Phase I extension plan shall not add any new control units or increase the total Phase I extension allowances requested; or

(iii) All elements required for an early ranking application and a statement that no early ranking application for the plan was submitted.

(e) *Administrator's Action.* (1) *Early ranking applications.* (i) The Administrator may approve in whole or in part or with changes or conditions, as appropriate, or disapprove an early ranking application.

(ii) The Administrator will act on each early ranking application in the order of receipt.

(ii) The Administrator will determine the order of receipt by the following procedures:

(A) Hand-delivered submissions and mailed submissions will be deemed to have been received on the date they are received by the Administrator; *provided* that all submissions received by the Administrator prior to the 40th day after publication of this subpart in the **Federal Register** will be deemed received on the 40th day.

(B) All submissions received by the Administrator on the same day will be deemed to have been received simultaneously.

(C) The order of receipt of all submissions received simultaneously will be determined by a public lottery if allocation of Phase I extension reserve allowances to each of the simultaneous submissions would result in oversubscription of the Phase I extension reserve.

(iv) Based on the allowances requested under paragraph (c)(9) of this section, as adjusted by the Administrator in approving the early ranking application, the Administrator will award Phase I extension reserve allowances for each complete early ranking application to the extent that allowances that have not been awarded remain in the Phase I extension reserve at the time the Administrator acts on the application. The allowances will be awarded in accordance with the procedures set forth the allocation of reserve allowances in paragraph (e)(3) of this section.

(v) The Administrator's action on an early ranking application shall be conditional on the Administrator's action on a timely and complete Acid Rain permit application that includes a complete Phase I extension plan and, where the plan includes a unit under paragraph (a)(1) (ii) and (iii) of this section, a complete substitution plan or reduced utilization plan, as appropriate.

(vi) Not later than 15 days after receipt of each early ranking application, the Administrator will notify, in writing, the designated representative of each application of the date that the early ranking application was received and one of the following:

(A) The award of allowances if the application was complete and the Phase I extension reserve as not oversubscribed;

(B) A determination that the application was incomplete and is disapproved; or

(C) If the Phase I extension reserve was oversubscribed, a list of the applications received on that date, the number of Phase I extension allowances requested in each application, and the

[1] In the case of a transfer unit that shares a common stack with a unit not listed in Table 1 of § 73.10(a) of this chapter and whose emissions of sulfur dioxide are not monitored separately or apportioned in accordance with part 75 of this chapter, the projected figures for the transfer unit under paragraph (c)(7) of this section must be for the units combined.

date, time, and location of a lottery to determine the order of receipt for all applications received on that date.

(vii) The date of a lottery for all applications received on a given day will not be earlier than 15 days after the Administrator notifies each designated representative whose applications were received on that date.

(viii) Any early ranking application may be withdrawn from the lottery if a letter signed by the designated representative of each unit governed by the application and requesting withdrawal is received by the Administrator before the lottery takes place.

(2) *Phase I extension plans.* (i) The Administrator will act on each Phase I extension plan in the order that the early ranking application for that plan was received or, if no early ranking application was received, in the order that the Phase I extension plan was received, as determined under paragraph (e)(1)(iii) of this section.

(ii) Based on the allowances requested under paragraph (c)(9) of this section, as adjusted under paragraph (d) of this section and by the Administrator in approving the Phase I extension plan, the Administrator will allocate Phase I extension reserve allowances to the Allowance Tracking System account of each control and transfer unit upon issuance of an Acid Rain permit containing the approved Phase I extension plan. The allowances will be allocated using the procedures set forth in paragraph (e)(3) of this section.

(iii) The Administrator will not approve a Phase I extension plan, even if it meets the requirements of this section, unless unallocated allowances remain in the Phase I extension reserve at the time the Administrator acts on the plan.

(3) *Allowance Allocations.* In addition to any allowances allocated in accordance with Table 1 of § 73.10(a) of this chapter and other approved compliance options, the Administrator will allocate Phase I extension reserve allowances to each eligible unit in a Phase I extension plan in the following order.

(i) For 1995, to each control unit in the order in which it is listed in the plan and then to each transfer unit in the order in which it is listed.

(ii) For 1996, to each control unit in the order in which it is listed in the plan and then to each transfer unit in the order in which it is listed.

(iii) For 1997, to each control unit in the order in which it is listed in the plan, then likewise for 1998, and then likewise for 1999.

(iv) The Administrator will allocate any Phase I extension reserve allowances returned to the Administrator to the next Phase I extension plan, in the rank order established under paragraph (e)(1)(iii) of this section, that continues to meet the requirements of this section and this part.

(f) *Special Provisions.* (1) *Emissions Limitations.*

(i) *Sulfur Dioxide.*

(A) If a control or transfer unit governed by an approved Phase I extension plan emits in 1997, 1998, or 1999 sulfur dioxide in excess of the projected controlled emissions for the unit specified for the year under paragraph (c)(7) of this section as adjusted under paragraph (d) of this section and by the Administrator in approving the Phase I extension plan, the Administrator will deduct allowances equal to such exceedence from the unit's annual allowance allocation in the following calendar year.[2]

(B) Failure to demonstrate at least a 90% reduction of sulfur dioxide in 1997, 1998, or 1999 in accordance with part 75 of this chapter at a control unit governed by an approved Phase I extension plan shall be a violation of this section. In the event of any such violation, in addition to any other liability under the Act, the Administrator will deduct allowances from the control unit's compliance subaccount for the year of the violation. The deduction will be calculated as follows:

Allowances deducted=(1−(percent reduction achieved+90%))×Phase I extension reserve allowances received

where:

"Percent reduction achieved" is the percent reduction determined in accordance with part 75 of this chapter.

"Phase I extension reserve allowances received" is the number of Phase I extension reserve allowances allocated for the year under paragraph (e)(2)(ii) of this section.

(ii) *Nitrogen Oxides.*

(A) Beginning on January 1, 1997, each control and transfer unit shall be subject to the Acid Rain emissions limitations for nitrogen oxides.

(B) Notwithstanding paragraph (f)(1)(ii)(A) of this section, a transfer unit shall be subject to the Acid Rain emissions limitations for nitrogen oxides, under section 407 of the Act and regulations implementing section 407 of the Act, beginning on January 1 of any year for which a transfer unit is allocated fewer Phase I extension reserve allowances than the maximum amount that the designated representative could have requested in accordance with paragraph (c)(5) of this section (as adjusted under paragraph (d) of this section and by the Administrator in approving the Phase I extension plan) unless the transfer unit is the last unit allocated Phase I extension reserve allowances under the plan.

(2) *Monitoring Requirements.* Each control unit shall comply with the special monitoring requirements for Phase I extension plans in accordance with part 75 of this chapter.

(3) *Reporting Requirements.* Each control and transfer unit shall comply with the special reporting requirements for Phase I extension plans in accordance with § 72.93.

(4) *Liability.* The owners and operators of a control or transfer unit governed by an approved Phase I extension plan shall be liable for any violation of the plan or this section at that or any other unit governed by the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and section 411 of the Act.

(5) *Termination.* A Phase I extension plan shall be in effect only in Phase I, and no Phase I extension plan shall be terminated before the end of Phase I. The designated representative may, however, withdraw a Phase I extension plan at any time prior to issuance of the Phase I Acid Rain permit that includes the Phase I extension plan, as adjusted.

§ 72.43 Phase I reduced utilization plans.

(a) *Applicability.* This section shall apply to:

(1) The designated representative of any Phase I unit, including:

(i) Any unit listed in Table 1 of § 73.10(a) of this chapter; and

(ii) Any other unit that becomes a Phase I unit (including any unit designated as a compensating unit under this section or a substitution unit under § 72.41).

(b)(1) The designated representative shall include in the Acid Rain permit application for a Phase I unit a reduced utilization plan, meeting the requirements of this section, when the owners and operators of the unit plan to:

(i) Reduce utilization of the unit below the unit's baseline to achieve compliance, in whole or in part, with the unit's Phase I Acid Rain emissions limitations for sulfur dioxide; and

[2] In the case of a transfer unit that shares a common stack with a unit not listed in Table 1 of § 73.10(a) of this chapter where the units are not monitored separately or apportioned in accordance with part 75 of this chapter, the combined emissions of both units will be deemed to be the transfer unit's emissions for purposes of applying paragraph (f)(1)(i) of this section.

(ii) Accomplish such reduced utilization through one or more of the following:

(A) Shifting generation of the unit to a compensating unit that would not otherwise be a Phase I unit or to a sulfur-free generator; or

(B) Using one or more energy conservation measures or improved unit efficiency measures.

(2)(i) Energy conservation measures shall be either demand-side measures implemented after December 31, 1987 in the residence or facility of a customer to whom the unit's utility system sells electricity or supply-side measures implemented after December 31, 1987 in facilities of the unit's utility system.

(ii) The utility system shall pay in whole or in part for the energy conservation measures either directly or, in the case of demand-side measures, through payment to another person who purchases the measure.

(iii) Energy conservation measures shall not include:

(A) Conservation programs that are exclusively informational or educational in nature;

(B) Load management measures that lead to reduction of electric energy demands during a utility's peak generating period, unless kilowatt hour savings can be verified under § 72.92; or

(C) Utilization of industrial waste gases, unless the designated representative certifies that there is no net increase in sulfur dioxide emissions from such utilization.

(iv) For calendar years when the unit's utility system is a subsidiary of a holding company and the unit's dispatch system is or includes all units that are interconnected and centrally dispatched and included in that holding company, then:

(A) Energy conservation measures shall be either demand-side measures implemented in the residence or facility of a customer to whom any utility system in the holding company sells electricity or supply-side measures implemented in facilities of any utility system in the holding company. Such utility system shall pay in whole or in part for the measures either directly or, in the case of demand-side measures, through payment to another person who purchases the measures.

(B) The limitations in paragraph (b)(2)(iii) of this section shall apply.

(3)(i) Improved unit efficiency measures shall be implemented in the unit. Such measures shall include supply-side measures listed in Appendix A, section 2.1 of part 73 of this chapter.

(ii) The utility system shall pay in whole or in part for the improved unit efficiency measures.

(4) The requirement to submit a reduced utilization plan shall apply in the event that the owners and operators of a Phase I unit decide, at any time during any Phase I calendar year, to rely on the method of compliance in paragraph (b)(1) of this section. In that case, the designated representative shall submit a reduced utilization plan not later than 90 days, or a notification to activate a conditionally approved plan in accordance with § 72.40(c) not later than 60 days, before the allowance transfer deadline applicable to the first year for which the plan is to take effect.

(5) The designated representative of each source with a unit designated as a compensating unit in any plan submitted under paragraphs (b) (1) or (4) of this section shall incorporate by reference in the permit application each such plan.

(c) *Contents of Reduced Utilization Plan.* A complete reduced utilization plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each Phase I unit for which the owners and operators plan reduced utilization.

(2) Except where the designated representative requests conditional approval of the plan, the first calendar year and, if known, the last calendar year in which the reduced utilization plan is to be in effect. Unless the designated representative specifies an earlier calendar year, the last calendar year shall be deemed to be 1999.

(3) A statement whether the plan designates a compensating unit or relies on sulfur-free generation, any energy conservation measure, or any improved unit efficiency measure to account for any amount of reduced utilization.

(4) If the plan designates a compensating unit, or relies on sulfur-free generation, to account for any amount of reduced utilization:

(i) Identification of the compensating unit or sulfur-free generator.

(ii) For each compensating unit, the allowance allocation calculated as the compensating unit's baseline multiplied by the lesser of the compensating unit's 1985 actual SO_2 emissions rate or 1985 allowable SO_2 emissions rate, divided by 2000 lbs/ton. If the compensating unit is a new unit, it shall be deemed to have a baseline of zero and shall be allocated no allowances.

(iii) For each sulfur-free generator, identification of any other Phase I units that designate the same sulfur-free generator in another plan submitted under paragraphs (b) (1) or (4) of this section.

(iv) For each compensating unit or sulfur-free generator not in the dispatch system of the unit reducing utilization under the plan, the system directives or power purchase agreements or other contractual agreements governing the purchase of the electrical energy that is generated by the compensating unit or sulfur-free generator and on which the plan relies to accomplish reduced utilization.

(5) The special provisions in paragraph (f) of this section.

(d) *Administrator's Action.* If the Administrator approves the reduced utilization plan, he or she will allocate allowances, as provided in the approved plan, to the Allowance Tracking System accounts for any designated compensating unit upon issuance of an Acid Rain permit containing the plan, except that, if the plan is conditionally approved, the allowances will be allocated upon revision of the permit to activate the plan.

(e) *Failure to Submit a Plan.* (1) The designated representative of a Phase I unit will be deemed not to violate, during a Phase I calendar year, the requirement to submit a reduced utilization plan under paragraph (b) (1) or (4) of this section:

(i) If a unit's adjusted utilization under § 72.91(a) for the year is less than or equal to zero.

(ii) If the unit's adjusted utilization under § 72.91(a) for the year is greater than zero, to the extent that the designated representative complies with the allowance surrender and other requirements of § 72.91 and § 72.92 of this chapter and demonstrates one or more of the following:

(A) The adjusted utilization was offset by adjusted utilization at other Phase I units in the unit's dispatch system;

(B) The adjusted utilization was caused by a dispatch-system-wide sales decline; *provided* that to the extent the percentage of adjusted utilization exceeds the percentage of dispatch-system-wide sales decline, the presumption of this paragraph will be rebuttable and will not apply to the extent the Administrator finds, based on clear and convincing evidence, that the dispatch-system-wide sales decline was not the cause;

(C) The adjusted utilization was caused by a forced outage at the unit; or

(D) The adjusted utilization was caused by economic dispatching that reflected changes in the unit's dispatch order in the dispatch system resulting from increases in the relative cost of generation at the unit (including increases due to the installation of

pollution control equipment or other equipment changes at the unit, the value of allowances saved or avoided, or changes in fuel supply) or by an order of a utility regulatory authority, with rate jurisdiction over an owner of the unit, issued for the purpose of achieving such economic dispatching.

(2) If a Phase I unit's adjusted utilization under § 72.91(a) for a Phase I calendar year is greater than zero and to the extent the demonstrations (if any) made in accordance with paragraph (e)(1) of this section fail to account for any of the adjusted utilization, the Administrator shall determine on a case-by-case basis whether the designated representative of the unit violated the requirement to submit a reduced utilization plan under paragraph (b) (1) or (4) of this section.

(i) Where measures (e.g., the use of low-sulfur coal) were taken at the unit to reduce its emissions rate for the year to 2.5 lbs/mmBtu or less, this will be considered an indicator that the adjusted utilization was not due to a failure to plan.

(ii) Where the adjusted utilization was due to a permanent shutdown of the unit or the owners and operators of the unit did not pursue methods of compliance sufficient to ensure compliance without reduced utilization, this will be considered an indicator of a failure to plan.

(3) Notwithstanding any demonstration or determination under paragraphs (e) (1) and (2) of this section, the designated representative of any Phase I unit shall surrender allowances in accordance with subpart I of this part.

(f) *Special Provisions.* (1) *Emissions Limitations.* (i) Any compensating unit designated under an approved reduced utilization plan shall become a Phase I unit from January 1 of the calendar year in which the plan takes effect until January 1 of the year for which the plan is no longer in effect or is terminated, except that such unit shall not become subject to the Acid Rain emissions limitations for nitrogen oxides in Phase I under section 407 of the Act and regulations implementing section 407 of the Act.

(ii) The designated representative of any Phase I unit (including a unit governed by a reduced utilization plan relying on energy conservation, improved unit efficiency, sulfur-free generation, or a compensating unit) shall surrender allowances, and the Administrator will deduct or return allowances, in accordance with subpart I of this part.

(2) *Reporting Requirements.* The designated representative of any Phase I unit (including a unit governed by a reduced utilization plan relying on energy conservation, improved unit efficiency, sulfur-free generation, or a compensating unit) shall comply with the special reporting requirements under §§ 72.91 and 72.92.

(3) *Liability.* The owners and operators of a unit governed by an approved reduced utilization plan shall be liable for any violation of the plan or this section at that or any other unit governed by the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and section 411 of the Act.

(4) *Termination.* (i) A reduced utilization plan shall be in effect only in Phase I for the calendar years specified in the plan or until the calendar year for which a termination of the plan takes effect; *provided* that no reduced utilization plan that designates a compensating unit that serves as a control unit under a Phase I extension plan shall be terminated, and no such unit shall be de-designated as a compensating unit, before the end of Phase I.

(ii) To terminate a reduced utilization plan for a given calendar year prior to its last year for which the plan was approved:

(A) A notification to terminate in accordance with § 72.40(d) shall be submitted no later than 60 days before the allowance transfer deadline applicable to the given year; and

(B) In the notification to terminate, the designated representative of any compensating unit governed by the plan shall state that he or she surrenders for deduction from the unit's Allowance Tracking System account allowances equal in number to, and with the same or an earlier compliance use date as, those allocated under paragraph (d) of this section to each compensating unit for the calendar years for which the plan is to be terminated. The designated representative may identify the serial numbers of the allowances to be deducted. In the absence of such identification, allowances will be deducted on a first-in, first-out basis under § 73.35(c)(2) of this chapter.

(iii) If the requirements of paragraph (f)(3)(ii) are met and upon revision of the permit to terminate the reduced utilization plan, the Administrator will deduct the allowances specified in paragraph (f)(3)(ii)(B) of this section. No reduced utilization plan shall be terminated, and no unit shall be de-designated as Phase I unit, unless such deduction is made.

§ 72.44 Phase II repowering extensions.

(a) *Applicability.* (1) This section shall apply to the designated representative of:

(i) Any existing affected unit that is a coal-fired unit and has a 1985 actual SO_2 emissions rate equal to or greater than 1.2 lbs/mmBtu.

(ii) Any new unit that will be a replacement unit, as provided in paragraph (b)(2) of this section, for a unit meeting the requirements of paragraph (a)(1)(i) of this section.

(iii) Any oil and/or gas-fired unit that has been awarded clean coal technology demonstration funding as of January 1, 1991 by the Secretary of Energy.

(2) A repowering extension does not exempt the owner or operator for any unit governed by the repowering plan from the requirement to comply with such unit's Acid Rain emissions limitations for sulfur dioxide.

(b) The designated representative of any unit meeting the requirements of paragraph (a)(1)(i) of this section may include in the unit's Phase II Acid Rain permit application a repowering extension plan that includes a demonstration that:

(1) The unit will be repowered with a qualifying repowering technology in order to comply with the Phase II emissions limitations for sulfur dioxide; or

(2) The unit will be replaced by a new utility unit that has the same designated representative and that is located at a different site using a qualified repowering technology and the existing unit will be permanently retired from service on or before the date on which the new utility unit commences commercial operation.

(c) In order to apply for a repowering extension, the designated representative of a unit under paragraph (a) of this section shall:

(1) Submit to the permitting authority, by January 1, 1996, a complete repowering extension plan;

(2) Submit to the Administrator, before June 1, 1997, a complete petition for approval of repowering technology; and

(3) If the repowering extension plan is submitted for conditional approval, submit by December 31, 1997, a notification to activate the plan in accordance with § 72.40(c).

(d) *Contents and Review of Petition for Approval of Repowering Technology* (1) A complete petition for approval of repowering technology shall include the following elements, in a format prescribed by the Administrator, concerning the technology to be used in a plan under paragraph (b) of this section and may follow the repowering

technology demonstration protocol issued by the Administrator:

(i) Identification and description of the technology

(ii) Vendor certification of the guaranteed performance characteristics of the technology, including:

(A) Percent removal and emission rate of each pollutant being controlled;

(B) Overall generation efficiency; and

(C) Information on the state, chemical constituents, and quantities of solid waste generated (including information on land-use requirements for disposal) and on the availability of a market to which any by-products may be sold.

(iii) If the repowering technology is not listed in the definition of a qualified repowering technology in § 72.2, a vendor certification of the guaranteed performance characteristics that demonstrate that the technology meets the criteria specified for non-listed technologies in § 72.2; *provided* that the existence of such guarantee shall not be a defense against the failure to meet the criteria for non-listed technologies.

(2) The Administrator may request any supplemental information that is deemed necessary to review the petition for approval of repowering technology.

(3) The Administrator shall review the petition for approval of repowering technology and, in consultation with the Secretary of Energy, shall make a conditional determination of whether the technology described in the petition is a qualifying repowering technology.

(4) Based on the petition for approval of repowering technology and the information provided under paragraph (d)(2) of this section and § 72.94(a), the Administrator will make a final determination of whether the technology described in the petition is a qualifying repowering technology.

(e) *Contents of Repowering Extension Plan.* A complete repowering extension plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the existing unit governed by the plan.

(2) The unit's federally-approved State Implementation Plan sulfur dioxide emissions limitation.

(3) The unit's 1995 actual SO_2 emissions rate.

(4) A schedule for construction, installation, and commencement of operation of the repowering technology approved or submitted for approval under paragraph (d) of this section, with dates for the following milestones:

(i) Completion of design engineering;

(ii) For a plan under paragraph (b)(1) of this section, removal of the existing unit from operation to install the qualified repowering technology;

(iii) Commencement of construction;

(iv) Completion of construction;

(v) Start-up testing;

(vi) For a plan under paragraph (b)(2) of this section, shutdown of the existing unit; and

(vii) Commencement of commercial operation of the repowering technology.

(5) For a plan under paragraph (b)(2) of this section:

(i) Identification of the new unit. A new unit shall not be included in more than one repowering extension plan.

(ii) Certification that the new unit will replace the existing unit.

(iii) Certification that the new unit has the same designated representative as the existing unit.

(iv) Certification that the existing unit will be permanently retired from service on or before the date the new unit commences commercial operation.

(6) The special provisions of paragraph (h) of this section.

(f) *Permitting Authority's Action on Repowering Extension Plan.* (1) The permitting authority shall not approve a repowering extension plan until the Administrator makes a conditional determination that the technology is a qualified repowering technology, unless the permitting authority conditionally approves such plan subject to the conditional determination of the Administrator.

(2) *Permit Issuance.* (i) Upon a conditional determination by the Administrator that the technology to be used in the repowering extension plan is a qualified repowering technology and a determination by the permitting authority that such plan meets the requirements of this section, the permitting authority shall issue the Acid Rain portion of the operating permit including:

(A) The approved repowering extension plan; and

(B) A schedule of compliance with enforceable milestones for construction, installation, and commencement of operation of the repowering technology and other requirements necessary to ensure that Phase II emission reduction requirements under this section will be met.

(ii) Except as otherwise provided in paragraph (g) of this section, the repowering extension shall be in effect starting January 1, 2000 and ending on the day before the date (specified in the Acid Rain permit) on which the existing unit will be removed from operation to install the qualifying repowering technology or will be permanently removed from service for replacement by a new unit with such technology; *provided* that the repowering extension shall end no later than December 31, 2003.

(iii) The portion of the operating permit specifying the repowering extension and other requirements under paragraph (f)(2)(i) of this section shall be subject to the Administrator's final determination, under paragraph (d)(4) of this section, that the technology to be used in the repowering extension plan is a qualifying repowering technology.

(3) *Allowance Allocation.* The Administrator will allocate allowances after issuance of an operating permit containing the repowering extension plan (or, if the plan is conditionally approved, after the revision of the Acid Rain permit under § 72.40(c)) and of the Administrator's final determination, under paragraph (d)(4) of this section, that the technology to be used in such plan is a qualifying repowering technology. Allowances will be allocated (including a pro rata allocation for any fraction of a year), as follows:

(i) To the existing unit under the approved plan, in accordance with section 409(c)(1) of the Act and part 73 of this chapter during the repowering extension under paragraph (f)(2)(ii) of this section; and

(ii) To the existing unit under the approved plan under paragraph (b)(1) of this section or, in lieu of any further allocations to the existing unit, to the new unit under the approved plan under paragraph (b)(2) of this section, in accordance with section 409(c) (2) through (4) of the Act and part 73 of this chapter after the repowering extension under paragraph (f)(2)(ii) of this section ends.

(g) *Failed Repowering Projects.* (1)(i) If, at any time before the end of the repowering extension under paragraph (f)(2)(ii) of this section, the designated representative of a unit governed by an approved repowering extension plan notifies the Administrator in writing that the owners and operators have decided to terminate efforts to properly design, construct, and test the repowering technology specified in the plan before completion of construction or start-up testing and demonstrates, in a proposed permit revision, to the Administrator's satisfaction that such efforts were in good faith, the unit shall not be deemed in violation of the Act because of such a termination. Where the preceding requirements of this paragraph are met, the permitting authority shall revise the operating permit in accordance with this paragraph and paragraph (g)(1)(ii) of this section and § 72.81 (permit modification).

(ii) Regardless of whether notification under paragraph (g)(1)(i) of this section

is given, the repowering extension will end beginning on the earlier of the date of such notification or the date by which the designated representative was required to give such notification under § 72.94(d). The Administrator will deduct allowances (including a pro rata deduction for any fraction of a year) from the Allowance Tracking System account of the existing unit to the extent necessary to ensure that, beginning the day after the extension ends, allowances are allocated in accordance with section 409(c) (2) through (4) of the Act and part 73 of this chapter.

(2) If the designated representative of a unit governed by an approved repowering extension plan demonstrates to the satisfaction of the Administrator, in a proposed permit revision, that the repowering technology specified in the plan was properly constructed and tested on such unit but was unable to achieve the emissions reduction limitations specified in the plan and that it is economically or technologically infeasible to modify the technology to achieve such limits, the unit shall not be deemed in violation of the Act because of such failure to achieve the emissions reduction limitations. In order to be properly constructed and tested, the repowering technology shall be constructed at least to the extent necessary for direct testing of the multiple combustion emissions (including sulfur dioxide and nitrogen oxides) from such unit while operating the technology at nameplate capacity. Where the preceding requirements of this paragraph are met:

(i) The permitting authority shall revise the Acid Rain portion of the operating permit in accordance with paragraphs (g)(2) (ii) and (iii) and § 72.81 (permit modification).

(ii) The existing unit may be retrofitted or repowered with another clean coal or other available control technology.

(iii) The repowering extension will continue in effect until the earlier of the date the existing unit commences commercial operation with such control technology or December 21, 2003. The Administrator will allocate or deduct allowances as necessary to ensure that allowances are allocated in accordance with paragraph (f)(3) of this section applying the repowering extension under this paragraph.

(h) *Special Provisions.* (1) *Emissions Limitations.* (i) *Sulfur Dioxide.* Allowances allocated during the repowering extension under paragraphs (f)(3) and (g)(2)(iii) of this section to a unit governed by an approved repowering extension plan shall not be transferred to any Allowance Tracking System account other than the unit accounts of other units at the same source as that unit.

(ii) *Nitrogen Oxides.* Any existing unit governed by an approved repowering extension plan shall be subject to the Acid Rain emissions limitations for nitrogen oxides in accordance with section 407 of the Act and regulations implementing section 407 of the Act beginning on the date that the unit is removed from operation to install the repowering technology or is permanently removed from service.

(iii) No existing unit governed by an approved repowering extension plan shall be eligible for a waiver under section 111(j) of the Act.

(iv) No new unit governed by an approved repowering extension plan shall receive an exemption from the requirements imposed under section 111 of the Act.

(2) *Reporting Requirements.* Each unit governed by an approved repowering extension plan shall comply with the special reporting requirements of § 72.94.

(3) *Liability.* (i) The owners and operators of a unit governed by an approved repowering plan shall be liable for any violation of the plan or this section at that or any other unit governed by the plan, including liability for fulfilling the obligations specified in part 77 of this chapter an section 411 of the Act.

(ii) The units governed by the plan under paragraph (b)(2) of this section shall continue to have a common designated representative until the existing unit is permanently retired under the plan.

(4) *Terminations.* Except as provided in paragraph (g) of this section, a repowering extension plan shall not be terminated after December 31, 1999.

Subpart E—Acid Rain Permit Contents

§ 72.50 General.

(a) Each Acid Rain permit (including any draft or proposed Acid Rain permit) will contain the following elements in a format prescribed by the Administrator:

(1) All elements required for a complete Acid Rain permit application under § 72.31 of this part, as approved or adjusted by the permitting authority;

(2) The applicable Acid Rain emissions limitation for sulfur dioxide; and

(3) The applicable Acid Rain emissions limitation for nitrogen oxides.

(b) Each Acid Rain permit is deemed to incorporate the definitions of terms under § 72.2 of this part.

§ 72.51 Permit shield.

Each affected unit operated in accordance with the Acid Rain permit that governs the unit and that was issued in compliance with title IV of the Act, as provided in this part and parts 73, 75, 77, and 78 of this chapter, and the regulations implementing section 407 of the Act, shall be deemed to be operating in compliance with the Acid Rain Program, except as provided in § 72.9(g)(6) of this part.

Subpart F—Federal Acid Rain Permit Issuance Procedures

§ 72.60 General.

(a) *Scope.* This subpart contains the procedures for federal issuance of Acid Rain permits for Phase I of the Acid Rain Program and Phase II for sources in States or geographic areas where the Administrator is the permitting authority as provided under regulations implementing title V of the Act. The procedures in this subpart do not apply to the issuance of Acid Rain permits by State permitting authorities with operating permit programs approved under part 70 of this chapter, except as expressly provided in subpart G of this part.

(b) *Permit Decision Deadlines.* The Administrator will issue or deny an Acid Rain permit under § 72.69(a) within 6 months of receipt of a complete Acid Rain permit application submitted for a unit, in accordance with § 72.21, at the U.S. EPA Regional Office for the Region in which the source is located.

§ 72.61 Completeness.

(a) *Determination of Completeness.* The Administrator will determine whether the Acid Rain permit application is complete within 30 days of receipt by the U.S. EPA Regional Office for the Region in which the source is located. The permit application shall be deemed to be complete if the Administrator fails to notify the designated representative to the contrary within 30 days of receipt.

(b) *Supplemental Information.* (1) Regardless of whether the Acid Rain permit application is complete under paragraph (a) of this section, the Administrator may require submission of any additional information that the Administrator determines to be necessary in order to review the Acid Rain permit application and issue an Acid Rain permit.

(2)(i) The designated representative shall submit the information required under paragraph (b)(1) of this section within 30 days after he or she is notified of the requirement for supplemental information unless the Administrator

allows for additional time to collect and submit the information.

(ii) If the designated representative fails to submit the supplemental information within the required time period, the Administrator may disapprove that portion of the Acid Rain permit application for the review of which the information was necessary and may deny the source an Acid Rain permit.

§ 72.62 Draft permit.

(a) After the Administrator receives a complete Acid Rain permit application and any supplemental information, the Administrator will issue a draft permit that incorporates in whole, in part, or with changes or conditions as appropriate, the permit application or deny the source a draft permit.

(b) The draft permit will be based on the information submitted by the designated representative of the affected source and other relevant information.

(c) The Administrator will serve a copy of the draft permit and the statement of basis on the designated representative of the affected source.

(d) The Administrator will provide a 30-day period for public comment, and opportunity to request a public hearing, on the draft permit or denial of a draft permit, in accordance with the public notice required under § 72.65(a)(1)(i) of this part.

§ 72.63 Administrative record.

(a) *Contents of the Administrative Record.* The Administrator will prepare an administrative record for an Acid Rain permit or denial of an Acid Rain permit. The administrative record will contain:

(1) The permit application and any supporting or supplemental data submitted by the designated representative;

(2) The draft permit;

(3) The statement of basis;

(4) Copies of any documents cited in the statement of basis and any other documents relied on by the Administrator in issuing or denying the draft permit (including any records of discussions or conferences with owners, operators, or the designated representative of affected units at the source or interested persons regarding the draft permit), or, for any such documents that are readily available, a statement of their location;

(5) Copies of all written public comments submitted on the draft permit or denial of a draft permit;

(6) The record of any public hearing on the draft permit or denial of a draft permit;

(7) The Acid Rain permit; and

(8) Any response to public comments submitted on the draft permit or denial of a draft permit and copies of any documents cited in the response and any other documents relied on by the Administrator to issue or deny the Acid Rain permit, or, for any such documents that are readily available, a statement of their location.

(b) [Reserved]

§ 72.64 Statement of basis.

(a) The statement of basis will briefly set forth significant factual, legal, and policy considerations on which the Administrator relied in issuing or denying the draft permit.

(b) The statement of basis will include:

(1) The reasons, and supporting authority, for approval or disapproval of any compliance options requested in the permit application, including references to applicable statutory or regulatory provisions and to the administrative record; and

(2) The name, address, and telephone, and facsimile numbers of the EPA office processing the issuance or denial of the draft permit.

§ 72.65 Public notice of opportunities of public comment.

(a)(1) The Administrator will give public notice of the following:

(i) The draft permit or denial of a draft permit and the opportunity for public review and comment and to request a public hearing; and

(ii) Date, time, location, and procedures for any scheduled hearing on the draft permit or denial of a draft permit.

(2) Any public notice given under this section may be for the issuance or denial of one or more draft permits.

(b) *Methods.* The Administrator will give the public notice required by this section by:

(1) Serving written notice on the following persons (except where such person has waived his or her right to receive such notice):

(i) The designated representative;

(ii) The State or local air pollution agency and any State or local utility regulatory authority with jurisdiction over the owners of any source or any unit covered by the Acid Rain permit application;

(iii) The State or local air pollution agency for any contiguous State whose air quality may be affected by, or for any State located within a 50-mile radius of, any source covered by the Acid Rain permit application; and

(iv) Any interested person.

(2) Giving notice by publication in the Federal Register and in a newspaper of general circulation in the area where the source covered by the Acid Rain permit application is located or in a State publication designed to give general public notice.

(c) *Contents.* All public notices issued under this section will contain the following information:

(1) Identification of the EPA office processing the issuance or denial of the draft permit for which the notice is being given.

(2) Identification of the designated representative for the affected source.

(3) Identification of each unit covered by the Acid Rain permit application and the draft permit.

(4) Any compliance options proposed for approval in the draft permit or for disapproval and the total allowances (including any under the compliance options) allocated to each unit if the Acid Rain permit application is approved.

(5) The address and office hours of a public location where the administrative record is available for public inspection and a statement that all information submitted by the designated representative and not protected as confidential under section 114(c) of the Act is available for public inspection as part of the administrative record.

(6) For public notice under paragraph (a)(1)(i) of this section, a brief description of the public comment procedures, including:

(i) A 30-day period for public comment beginning the date of publication of the notice or, in the case of an extension or reopening of the public comment period, such period as the Administrator deems appropriate;

(ii) The address where public comments should be sent;

(iii) Required formats and contents for public comment;

(iv) An opportunity to request a public hearing to occur not earlier than 15 days after public notice is given and the location, date, time, and procedures of any scheduled public hearing; and

(v) Any other means by which the public may participate.

(d) *Extensions and Reopenings of the Public Comment Period.* On the Administrator's own motion or on the request of any person, the Administrator may, at his or her discretion, extend or reopen the public comment period where he or she finds that doing so will contribute to the decision-making process by clarifying one or more significant issues affecting the draft permit or denial of a draft permit. Notice of any such extension or reopening shall be given under paragraph (a)(1)(i) of this section.

§ 72.66 Public comments.

(a) *General.* During the public comment period, any person may submit written comments on the draft permit or the denial of a draft permit.

(b) *Form.* (1) Comments shall be submitted in duplicate.

(2) The submission shall clearly indicate the draft permit issuance or denial to which the comments apply.

(3) The submission shall clearly indicate the name of the person commenting, his or her interest in the matter, and his or her affiliation, if any, to owners and operators of any unit covered by the Acid Rain permit application.

(c) *Contents.* Timely comments on any aspect of the draft permit or denial or a draft permit will be considered unless they concern:

(1) Any standard requirement under § 72.9;

(2) Issues that are not relevant, such as:

(i) The environmental effects of acid rain, acid deposition, sulfur dioxide, or nitrogen oxides generally; and

(ii) Permit issuance procedures, or actions on other permit applications, that are not relevant to the draft permit issuance or denial in question.

(d) Persons who do not wish to raise issues concerning the issuance or denial of the draft permit, but who wish to be notified of any subsequent actions concerning such matter may so indicate in writing during the public comment period or at any other time. The Administrator will place their names on a list of interested persons.

§ 72.67 Opportunity for public hearing.

(a) During the public comment period, any person may request a public hearing. A request for a public hearing shall be made in writing and shall state the issues proposed to be raised in the hearing.

(b) On the Administrator's own motion or on the request of any person, the Administrator may, at his or her discretion, hold a pubic hearing whenever the Administrator finds that such a hearing will contribute to the decision-making process by clarifying one or more significant issues affecting the draft permit or denial of a draft permit. Public hearings will not be held on issues under § 72.66(c) (1) and (2).

(c) During a public hearing under this section, any person may submit oral or written comments concerning the draft permit or denial of a draft permit. The Administrator may set reasonable limits on the time allowed for oral statements and will require the submission of a written summary of each oral statement.

(d) The Administrator will assure that a record is made of the hearing.

§ 72.68 Response to comments.

(a) The Administrator will consider comments on the draft permit or denial of a draft permit that are received during the public comment period and any public hearing. The Administrator is not required to consider comments otherwise received.

(b) In issuing or denying an Acid Rain permit, the Administrator will:

(1) Identify any permit provision or portion of the statement of basis that has been changed and the reasons for the change; and

(2) Briefly describe and respond to relevant comments under paragraph (a) of this section.

§ 72.69 Issuance and effective date of Acid Rain permits.

(a) After the close of the public comment period, the Administrator will issue or deny an Acid Rain permit. The Administrator will serve a copy of any Acid Rain permit and the response to comments on the designated representative for the source covered by the issuance or denial and serve written notice of the issuance or denial on any persons who are entitled to written notice under § 72.65(b)(1) (ii), (iii), and (iv) of this part. The Administrator will also give notice in the **Federal Register.**

(b)(1) The term of every Acid Rain permit shall be 5 years commencing on its effective date.

(2) Every Acid Rain permit for Phase I shall take effect on January 1, 1995.

Subpart G—Acid Rain Phase II Implementation

§ 72.70 Relationship to title V operating permit program.

(a) *Scope.* This subpart sets forth criteria for approval of State operating permit programs and the requirements with which State permitting authorities with approved programs shall comply, and with which the Administrator will comply in the absence of an approved State program, to issue Phase II Acid Rain permits.

(b) *Relationship to Operating Permit Program.* Each State permitting authority with an affected source shall act in accordance with this part and part 70, and part 78 of this chapter for the purpose of incorporating Acid Rain Program requirements into each affected source's operating permit or for issuing written exemptions under §§ 72.7 and 72.8. To the extent that any requirements of this part and part 78 of this chapter are inconsistent with the requirements of part 70 of this chapter, this part and part 78 of this chapter shall take precedence and shall govern the issuance, denial, revision, reopening, renewal, and appeal of the Acid Rain portion of an operating permit. For purposes of applying this subpart, the provisions of this subpart and of part 70 applicable to Acid Rain permit applications and draft, proposed, and final Acid Rain permits shall also apply to petitions for exemption and draft, proposed, and final written exemptions respectively for new or retired units to the extent consistent with §§ 72.7 and 72.8 of this chapter.

§ 72.71 Approval of state programs—general.

(a) Each State shall submit, to the Administrator for approval, a proposed operating permit program meeting the requirements of this subpart and part 70 of this chapter.

(b) The Administrator will act on State submissions of an operating permit program in accordance with the schedule and procedures set forth in § 70.4(e) of this chapter. The Administrator will approve State programs that conform to the applicable requirements of this subpart and § 70.4(b) of this chapter.

(c)(1) After approval of a State operating permit program, the Administrator will suspend, in accordance with this part and part 70 of this chapter, federal issuance of Acid Rain permits for Phase II for sources and units subject to the State program.

(2) The Administrator will issue all Acid Rain permits for Phase I. However, the Administrator reserves the right to delegate the remaining administration of Acid Rain permits for Phase I to approved State operating permit programs.

§ 72.72 State permit program approval criteria.

A State operating permit program shall meet the following criteria concerning the Acid Rain Program. Any aspect of the State program or any implementation of the State program that is inconsistent with these criteria shall be grounds for disapproval or withdrawal of approval of the State program by the Administrator:

(a) *Non-Interference with Acid Rain Program.* The State operating permit program shall not include or implement any measures that would interfere with the Acid Rain Program. In particular, the State program shall not restrict or interfere with allowance trading and shall not interfere with the Administrator's decision on an offset plan. Aspects and implementation of the State program that would constitute interference with the Acid Rain

Program, and are thus prohibited, include but are not limited to:

(1) Prohibitions, inconsistent with the Acid Rain Program, on the acquisition or transfer of allowances by an affected unit under the jurisdiction of the State permitting authority;

(2) Restrictions, inconsistent with the Acid Rain Program, on an affected unit's ability to sell or otherwise obligate its allowances;

(3) Requirements that an affected unit maintain a balance of allowances in excess of the level determined to be prudent by any utility regulatory authority with jurisdiction over the owners of the affected unit;

(4) Failing to notify the Administrator of any State administrative or judicial appeals of, or decisions covering, Acid Rain permit provisions that might affect Acid Rain Program requirements;

(5) Issuing an order, inconsistent with the Acid Rain Program, interpreting Acid Rain Program requirements as not applicable to an affected source or an affected unit in whole or in part or otherwise adjusting the requirements;

(6) Withholding approval of any compliance option that meets the requirements of the Acid Rain Program; or

(7) Any other aspect of implementation that the Administrator determines would hinder the operation of the Acid Rain Program.

(b) The State operating permit program shall require the following:

(1) *Acid Rain Permit Issuance.* Issuance or denial of Acid Rain permits shall follow the procedures under this part and part 70 of this chapter including:

(i) *Permit Application.* (A) *Requirement to Comply.* The owners and operators and the designated representative for each affected source under jurisdiction of the State permitting authority shall be required to comply with subparts B, C, and D of this part.

(B) *Effect of an Acid Rain Permit Application.* A complete Acid Rain permit application shall be binding on the owners and operators and the designated representative of the affected source, all affected units at the source, and any other unit governed by the permit application and shall be enforceable as an Acid Rain permit, from the date of submission of the permit application until the issuance or denial of the Acid Rain permit under paragraph (b)(1)(vii) of this section.

(C) *Submission to the Administrator.* The State permitting authority shall submit a written notice of application completeness to the Administrator within 10 working days following a determination by the State permitting authority that the Acid Rain permit application is complete.

(ii) *Draft Permit.* (A) The State permitting authority shall prepare the draft Acid Rain permit in accordance with subpart E of this part or deny a draft Acid Rain permit.

(B) The State permitting authority shall prepare a statement of basis in accordance with the requirements for a statement of basis under § 72.64 of this part.

(iii) *Notice to Administrator.* The State permitting authority shall submit a copy of the draft Acid Rain permit and the statement of basis to the Administrator and all other relevant portions of the operating permit that may affect the draft Acid Rain permit. This submission requirement will not be waived.

(iv) *Public Notice and Comment Period.* Public notice of the issuance or denial of the draft Acid Rain permit and the opportunity to comment and request a public hearing shall be given by publication in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice. A notice shall be served on those persons required to receive notice under §§ 70.7(h) and 70.8(b) of this chapter.

(v) *Proposed Permit.* Following the public notice and comment period on a draft Acid Rain permit, the permitting authority shall incorporate all changes necessary and issue a proposed Acid Rain permit in accordance with subpart E of this part or deny a proposed Acid Rain permit.

(vi) *Submittal to Administrator.* (A) The State permitting authority shall submit the proposed Acid Rain permit or denial of a proposed Acid Rain permit to the Administrator in accordance with § 70.8(a) of this chapter, the provisions of which shall be treated as applying to the issuance or denial of a proposed Acid Rain permit.

(B) The Administrator will review the proposed Acid Rain permit or denial of a proposed Acid Rain permit in accordance with § 70.8(c) of this chapter, the provisions of which shall be treated as applying to the issuance or denial of a proposed Acid Rain permit.

(vii) *Acid Rain Permit Issuance.* Following the Administrator's review of the proposed Acid Rain permit or denial of a proposed Acid Rain permit, the State permitting authority shall or, under § 70.8(c) of this chapter (treated as applying to the issuance or denial of an Acid Rain permit), the Administrator will, incorporate any required changes and issue or deny the Acid Rain permit in accordance with subpart E of this part.

(viii) *Effective Date of Acid Rain Permit.* Each source's Acid Rain permit issued by a State permitting authority under this section shall be effective for a period of 5 years.

(ix) *New Owners.* An Acid Rain permit shall be binding on any new owner or operator or designated representative of any source or unit governed by the permit.

(x) Each Acid Rain permit (including a draft or proposed permit) shall contain all applicable Acid Rain requirements, shall be a complete and segregable portion of the operating permit, and shall not incorporate information contained in any other documents, other than documents that are readily available.

(xi) Invalidation of the Acid Rain portion of an operating permit shall not affect the continuing validity of the rest of the operating permit, nor shall invalidation of any other portion of the operating permit affect the continuing validity of the Acid Rain portion of the permit.

(xii) No Acid Rain permit (including a draft or proposed permit) shall be issued unless the Administrator has received a certificate of representation for the designated representative of the source in accordance with subpart B of this part.

(xiii) Notwithstanding any State law providing that a permit must be issued by default after a specified time, no Acid Rain permit shall be issued until the Administrator and other States have had an opportunity to review a proposed Acid Rain permit as provided in this section and § 70.8(b) of this chapter.

(xiv) Except as provided in § 72.73(b), the State permitting authority shall issue or deny an Acid Rain permit within 18 months of receiving a complete Acid Rain permit application submitted for an affected unit in accordance with § 72.21 or such lesser time approved under part 70 of this chapter.

(2) *Permit Revisions.* In acting on any Acid Rain permit revision, the State permitting authority shall follow the provisions and procedures set forth at subpart H of this part.

(3) *Permit Renewal.* The renewal of an Acid Rain permit for an affected source shall be subject to all the requirements of this subpart pertaining to the issuance of permits.

(4) *Acid Rain Program Forms.* In developing the Acid Rain portion of the operating permit, the permitting authority shall use the applicable forms or other formats prescribed by the

Administrator under the Acid Rain Program; *provided* that the Administrator may waive this requirement in whole or in part.

(5) *Acid Rain Appeal Procedures.* (i) Appeals of the Acid Rain portion of an operating permit issued by the State permitting authority that do not challenge or involve decisions or actions of the Administrator under this part, parts 73, 75, 77 and 78 of this chapter, and sections 407 and 410 of the Act and regulations implementing sections 407 and 410 shall be conducted according to procedures established by the State under § 70.4(b)(3)(x) of this chapter. Appeals of the Acid Rain portion of such a permit that challenge or involve such decisions or actions of the Administrator shall follow the procedures under part 78 of this chapter and section 307 of the Act. Such decisions or actions include, but are not limited to, allowance allocations, determinations concerning alternative monitoring systems, and determinations of whether a technology is a qualifying repowering technology.

(ii) Under no circumstances shall a State administrative appeal or judicial appeal of the Acid Rain portion of an operating permit be allowed more than 90 days (or such shorter period as provided by the applicable State appeals procedures) following respectively issuance of the Acid Rain portion that is subject to administrative appeal or issuance of the final agency action subject to judicial appeal.

(iii) The State permitting authority shall serve written notice on the Administrator of any State administrative or judicial appeal concerning as Acid Rain provision of any operating permit or denial of an Acid Rain portion of any operating permit within 30 days of the filing of the appeal.

(iv) Any State administrative permit appeals procedures shall ensure that the Administrator may intervene as a matter of right in any permit appeal involving an Acid Rain permit provision or denial of an Acid Rain permit.

(v) The State permitting authority shall serve written notice on the Administrator of any determination or order in a State administrative or judicial proceeding that interprets, modifies, voids, or otherwise relates to any portion of an Acid Rain permit. Following any such determination or order, the Administrator will have an opportunity to review and veto the Acid Rain permit or revoke the permit for cause in accordance with § 70.8 of this chapter.

(vi) A failure of the State permitting authority to issue an Acid Rain permit in accordance with § 72.73(b)(1)(i) shall be ground for filing an appeal.

(vii) No appeal concerning an Acid Rain requirement shall result in a stay of any provision of the Acid Rain permit for which a stay is barred under part 78 of this chapter.

(6) *Cooperation with Utility Regulatory Authority.* In considering any Acid Rain permit application, the State permitting authority shall ensure coordination with any utility regulatory authority with jurisdiction over the owners of the affected unit.

(7) *New Units and Retired Units Exemptions.* The State permitting authority shall act in accordance with §§ 72.7 and 72.8 on any petition for exemption of a new unit or retired unit from requirements of the Acid Rain Program.

(8) *State Permit Evaluation.* The State permitting authority shall periodically evaluate the extent to which its operating permit program meets the Acid Rain Program requirements and supports a cost-effective implementation of the program. The permit fee rates set by the State permitting authority shall be adequate to cover such evaluation.

§ 72.73 State issuance of Phase II permits.

(a) *State Permit Issuance.* (1) A State with an operating permit program that has been approved by the Administrator under this part and part 70 of this chapter on or before July 1, 1996, shall be responsible for issuing Acid Rain permits for Phase II to all affected sources in that State.

(2) A State that has obtained interim operating permit program approval (as defined in § 70.4(d) of this chapter) on or before July 1, 1996 shall be responsible for issuing Acid Rain permits for Phase II to all affected sources in that State.

(3) A State that has obtained partial operating permit program approval (as defined in § 70.4(c) of this chapter) on or before July 1, 1996 shall be responsible for issuing Acid Rain permits for Phase II to all affected sources in the geographic area to which the partial approval applies.

(4) The State permitting authority shall comply with the procedures for issuance, revision, renewal, and appeal of Acid Rain permits under this subpart.

(b) *Permit Issuance Deadline.* (1)(i) On or before December 31, 1997, a State with an approved operating permit program shall issue an Acid Rain permit for Phase II to each affected source in the geographic area for which the program is approved as set forth in paragraph (a) of this section; *provided* that the designated representative of the source submitted a timely and complete Acid Rain permit application in accordance with § 72.21 of this part and meets the requirements of this subpart and part 70 of this chapter.

(ii) Each Acid Rain permit issued in accordance with this section shall have a term of 5 years commencing on its effective date. Each Acid Rain permit issued in accordance with paragraph (b)(1)(i) of this section shall take effect by the later of January 1, 2000, or, where the permit governs a unit under § 72.6(a)(3) of this part, the deadline for monitor certification under part 75 of this chapter.

(2) *Nitrogen Oxides.* Not later than January 1, 1999, the State permitting authority shall reopen the Acid Rain permit to add the Acid Rain Program nitrogen oxides requirements; *provided* that the designated representative of the affected source submitted a timely and complete Acid Rain permit application for nitrogen oxides in accordance with § 72.21. Such reopening shall not affect the term of the Acid Rain portion of an operating permit.

§ 72.74 Federal issuance of Phase II permits.

(a) The Administrator will be responsible for issuing Acid Rain permits for Phase II for any affected sources in a geographic area (including a State) that does not have an operating permit program with full, partial, or interim approval by the Administrator on or before July 1, 1996, under part 70 of this chapter. After approval of a State program, the Administrator will suspend, in accordance with this part and part 70 of this chapter, federal issuance of such permits for sources in the geographic area covered by the State program and the State shall be responsible for issuing such permits in accordance with § 72.73 of this part.

(b) *Permit Issuance Deadline.* (1)(i) On or before January 1, 1998, the Administrator will issue an Acid Rain permit for Phase II governing Acid Rain Program sulfur dioxide requirements to each affected source in a geographic area that, on July 1, 1996, did not have an approved operating permit program under part 70 of this chapter; *provided* that the designated representative for the source submitted a timely and complete Acid Rain permit application in accordance with § 72.21 of this part. The failure by the Administrator to issue a permit in accordance with this paragraph shall be grounds for the filing of an appeal under part 78 of this chapter.

(ii) Notwithstanding paragraph (b)(1)(i) of this section, the Administrator may delegate to any State

that obtains operating permit program approval after July 1, 1996, responsibility for permit review and implementation.

(iii) Each Acid Rain permit issued in accordance with this section shall have a term of 5 years commencing on its effective date. Each Acid Rain permit issued in accordance with paragraph (b)(1) shall take effect by the later of January 1, 2000 or, where a permit governs a under § 72.6(a)(3) of this part, the deadline for monitor certification under part 75 of this chapter.

(2) *Nitrogen Oxides.* Not later than 6 months following submission by the designated representative of a timely and complete Acid Rain permit application for nitrogen oxides, the Administrator shall reopen the Acid Rain permit for Phase II to add the Acid Rain Program nitrogen oxides requirements. Such reopening shall not affect the term of the Acid Rain permit.

(c) *Permit Issuance.* The Administrator will issue Acid Rain permits for Phase II in accordance with subparts E and F of this part and the regulations implementing title V of the Act.

Subpart H—Permit Revisions

§ 72.80 General.

(a) This subpart shall govern revisions to any Acid Rain permit issued by the Administrator and to the Acid Rain portion of any operating permit issued by a State with an approved operating permit program under part 70 of this chapter.

(b) The provisions of this subpart shall supersede the operating permit revision procedures specified in part 70 of this chapter with regard to revision of any Acid Rain Program permit provision.

(c) A permit revision may be submitted for approval at any time. No permit revision shall affect the term of the Acid Rain permit to be revised. No permit revision shall excuse any violation of an Acid Rain Program requirement that occurred prior to the effective date of the revision.

(d) The terms of the Acid Rain permit shall apply while the permit revision is pending.

(e) Any determination or interpretation by a State (including a State court) modifying or voiding any Acid Rain permit provision shall be subject to review by the Administrator in accordance with § 70.8(c) of this chapter as applied to permit modifications, unless the determination or interpretation is an administrative amendment approved in accordance with § 72.83 of this part.

(f) The standard requirements of § 72.9 of this part shall not be modified or voided by a permit revision.

(g) Any permit revision involving incorporation of a compliance option that was not submitted for approval and comment during the permit issuance process, or involving a change in a compliance option that was previously submitted, shall meet the requirements for applying for such compliance option under subpart D and section 407 of the Act and regulations implementing section 407 of the Act.

(h) For permit revisions not described in §§ 72.81 and 72.82 of this part, the permitting authority may, in its discretion, determine which of these sections is applicable.

§ 72.81 Permit modifications.

(a) Permit revisions that shall follow the permit modification procedures are:

(1) Relaxation of an excess emission offset requirement after approval of the offset plan by the Administrator;

(2) Incorporation of a final nitrogen oxides alternative emission limitation following a demonstration period;

(3) Determinations concerning failed repowering projects under § 72.44(g)(1)(i) and (2) of this part.

(b) The following permit revisions shall follow, at the option of the designated representative submitting the permit revision, either the permit modification procedures or the fast-track modification procedures under § 72.82 of this part:

(1) Consistent with paragraph (a) of this section, incorporation of a compliance option that the designated representative did not submit for approval and comment during the permit issuance process; except that incorporation of a reduced utilization plan that was not submitted during the permit issuance process, that does not designate a compensating unit, and that meets the requirements of § 72.43 of this part, may use the administrative permit amendment procedures under § 72.83 of this part;

(2) Changes in a substitution plan or reduced utilization plan that result in the addition of a new substitution unit or a new compensating unit under the plan;

(3) Addition of a nitrogen oxides averaging plan to a permit; and

(4) Changes in a Phase I extension plan, repowering plan, nitrogen oxides averaging plan, or nitrogen oxides compliance deadline extension.

(c)(1) Permit modifications shall follow the permit issuance requirements of:

(i) Subparts E, F, and G of this part, where the Administrator is the permitting authority; or

(ii) Subpart G of this part and § 70.7(e)(4)(ii) of this chapter, where the State is the permitting authority.

(2) For purposes of applying paragraph (c)(1) of this section, a permit modification shall be treated as an Acid Rain permit application, to the extent consistent with this subpart.

§ 72.82 Fast-track modifications.

The following procedures shall apply to all fast-track modifications.

(a) The designated representative shall serve a copy of the fast-track modification on the Administrator, the permitting authority, and any person entitled to a written notice under § 72.65(b)(1) (ii), (iii) and (iv) of this part. Within 5 business days of serving such copies, the designated representative shall also give public notice by publication in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

(b) The public shall have a period of 30 days, commencing on the date of publication of the notice, to comment on the fast-track modification. Comments shall be submitted in writing to the permitting authority and to the designated representative.

(c) The designated representative shall submit the fast-track modification to the permitting authority on or before commencement of the public comment period.

(d) Within 30 days of the close of the public comment period, the permitting authority shall consider the fast-track modification and the comments received and approve, in whole or in part or with changes or conditions as appropriate, or disapprove the modification. A fast-track modification shall be effective immediately upon issuance, in accordance with § 70.7(a)(1)(v) of this chapter as applied to significant permit modifications.

§ 72.83 Administrative permit amendment.

(a) Acid Rain permit revisions that shall follow the administrative permit amendment procedures are:

(1) Activation of a compliance option conditionally approved by the permitting authority; *provided* that all requirements for activation under subpart D of this part are met;

(2) Changes in the designated representative or alternative designated representative; *provided* that a new certificate of representation is submitted;

(3) Correction of typographical errors;

(4) Changes in names, addresses, or telephone or facsimile numbers;

(5) Changes in the owners or operators; *provided* that a new

certificate of representation is submitted within 30 days;

(6) Termination of a compliance option in the permit; *provided* that all requirements for termination under subpart D of this part shall be met and this procedure shall not be used to terminate a repowering plan after December 31, 1999 or a Phase I extension plan;

(7) Changes in a substitution or reduced utilization plan that do not result in the addition of a new substitution unit or a new compensating unit under the plan;

(8) Changes in the date, specified in a unit's Acid Rain permit, of commencement of operation of qualifying Phase I technology, *provided* that they are in accordance with § 72.42 of this part;

(9) Changes in the date, specified in a new unit's Acid Rain permit, of commencement of operation or the deadline for monitor certification, *provided* that they are in accordance with § 72.9 of this part;

(10) The addition of or change in a nitrogen oxides alternative emissions limitation demonstration period, *provided* that the requirements of regulations implementing section 407 of the Act are met; and

(11) Incorporation of changes that the Administrator has determined to be similar to those in paragraphs (a) (1) through (10) of this section.

(b) Administrative amendments shall follow the procedures set forth at § 70.7(d)(3) of this chapter. Where the State is the permitting authority, the permitting authority shall submit the revised portion of the permit to the Administrator within 10 working days after the date of final action on the request for an administrative amendment.

§ 72.84 Automatic permit amendment.

The following permit revisions shall be deemed to amend automatically, and become a part of the affected unit's Acid Rain permit by operation of law without any further review:

(a) Upon recordation by the Administrator under part 73 of this chapter, all allowance allocations to, transfers to, and deductions from an affected unit's Allowance Tracking System account; and

(b) Incorporation of an offset plan that has been approved by the Administrator under part 77 of this chapter.

§ 72.85 Permit reopenings.

(a) As provided in § 70.7(f) of this chapter, the permitting authority shall reopen an Acid Rain permit for cause, including whenever additional requirements become applicable to any affected unit governed by the permit.

(b) In reopening an Acid Rain permit for cause, the permitting authority shall issue a draft permit changing the provisions, or adding the requirements, for which the reopening was necessary. The draft permit shall be subject to the requirements of subparts E, F, and G of this part.

(c) As provided in §§ 72.73(b)(2) and 72.74(b)(2) of this part, the permitting authority shall reopen an Acid Rain permit to incorporate nitrogen oxides requirements, consistent with section 407 of the Act and regulations implementing section 407 of the Act.

(d) Any reopening of an Acid Rain permit shall not affect the term of the permit.

Subpart I—Compliance Certification

§ 72.90 Annual compliance certification report.

(a) *Applicability and Deadline.* For each calendar year in which a unit is subject to the Acid Rain emissions limitations, the designated representative of the source at which the unit is located shall submit to the Administrator, within 60 days after the end of the calendar year, an annual compliance certification report for the unit.

(b) *Contents of Report.* The designated representative shall include in the annual compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning the unit and the calendar year covered by the report:

(1) Identification of the unit;

(2) For all Phase I units, the information in accordance with §§ 72.91(a) and 72.92(a) of this part;

(3) If the unit is governed by an approved Phase I extension plan, then the information in accordance with § 72.93 of this part;

(4) At the designated representative's option, the total number of allowances to be deducted for the year, using the formula in § 72.95 of this part, and the serial numbers of the allowances that are to be deducted;

(5) At the designated representative's option, for units that share a common stack and whose emissions of sulfur dioxide are not monitored separately or apportioned in accordance with part 75 of this chapter, the percentage of the total number of allowances under paragraph (b)(4) of this section for all such units that is to be deducted from each unit's compliance subaccount; and

(6) The compliance certification under paragraph (c) of this section.

(c) *Annual Compliance Certification.* In the annual compliance certification report under paragraph (a) of this section, the designated representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the source and the affected units at the source in compliance with the Acid Rain Program, whether each affected unit for which the compliance certification is submitted was operated during the calendar year covered by the report in compliance with the requirements of the Acid Rain Program applicable to the unit, including:

(1) Whether the unit was operated in compliance with the applicable Acid Rain emissions limitations, including whether the unit held allowances, as of the allowance transfer deadline, in its compliance subaccount (after accounting for any allowance deductions under § 73.34(c) of this chapter) not less than the unit's total sulfur dioxide emissions during the calendar year covered by the annual report;

(2) Whether the monitoring plan that governs the unit has been maintained to reflect the actual operation and monitoring of the unit and contains all information necessary to attribute monitored emissions to the unit;

(3) Whether all the emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports;

(4) Whether the facts that form the basis for certification of each monitor at the unit or a group of units (including the unit) using a common stack or for using an Acid Rain Program excepted monitoring method or approved alternative monitoring method, if any, has changed; and

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitor recertification.

§ 72.91 Phase I unit adjusted utilization.

(a) *Annual Compliance Certification Report.* The designated representative for each Phase I unit shall include in the annual compliance certification report the unit's adjusted utilization for the

calendar year covered by the report, calculated as follows:

Adjusted utilization-baseline–actual utilization–plan reductions+ compensating generation provided to other units

where:

(1) "Baseline" is as defined in § 72.2 of this part.

(2) "Actual utilization" is the actual annual heat input (in mmBtu) of the unit for the calendar year determined in accordance with part 75 of this chapter.

(3) "Plan reductions" are the reductions in actual utilization, for the calendar year, below the baseline that are accounted for by an approved reduced utilization plan. The designated representative for the unit shall calculate the "plan reductions" (in mmBtu) using the following formula and converting all values in Kwh to mmBtu using the actual annual average heat rate (Btu/Kwh) of the unit (determined in accordance with part 75 of this chapter) before the employment of any improved unit efficiency measures under an approved plan:

Plan reductions=reduction from energy conservation+reduction from improved unit efficiency improvements+shifts to designated sulfur-free generators+shifts to designated compensating units

where:

(i) "Reduction from energy conservation" is a good faith estimate of the expected kilowatt hour savings during the calendar year from all conservation measures under the reduced utilization plan and the corresponding reduction in heat input (in mmBtu) resulting from those savings. The verified amount of such reduction shall be submitted in accordance with paragraph (b) of this section.

(ii) "Reduction from improved unit efficiency" is a good faith estimate of the expected improvement in heat rate during the calendar year and the corresponding reduction in heat input (in mmBtu) at the Phase I unit as a result of all improved unit efficiency measures under the reduced utilization plan. The verified amount of such reduction shall be submitted in accordance with paragraph (b) of this section.

(iii) "Shifts to sulfur-free generators" is the reduction in utilization (in mmBtu), for the calendar year, that is accounted for by all sulfur-free generators designated under the reduced utilization plan and documented under paragraph (a)(6) of this section. This term equals the sum, for all such generators, of the "shift to sulfur-free generator" calculated for each generator using the following formula:

Shift to sulfur-free generator–actual sulfur-free utilization–[(average 1985–87 sulfur-free annual utilization) (1+percentage change in dispatch system sales)]

where:

(A) "Actual sulfur-free utilization" is the actual annual generation (in Kwh) of the designated sulfur-free generator for the calendar year converted to mmBtus.

(B) "Average 1985–87 sulfur-free utilization" is the sum of annual generation (in Kwh) for 1985, 1986, and 1987 for the designated sulfur-free generator, divided by three and converted to mmBtus.

(C) "Percentage change in dispatch system sales" is calculated as follows:

$$\text{Percentage change in dispatch system sales} = [S_c - (\sum_{y=1985}^{1987} S_y \div 3)] \div [\sum_{y=1985}^{1987} S_y \div 3]$$

where:

S=dispatch system sales (in Kwh)
c=calendar year
y=1985, 1986, or 1987

If the result of the formula for percentage change in dispatch system sales is less than or equal to zero, then percentage change in dispatch system sales shall be treated as zero only for purposes of paragraph (a)(3)(iii) of this section.

(D) If the result of the formula for "shift to sulfur-free generator" is less than or equal to zero, then "shift to sulfur-free generator" is zero.

(iv) "Shifts to designated compensating units" is the reduction in utilization (mmBtu) that is accounted for by increased generation at compensating units designated under the reduced utilization plan. This term equals the heat rate (Btu/Kwh) of the unit reducing utilization multiplied by the sum, for all such compensating units, of the "generation shifted to designated compensating unit" for each compensating unit. "Generation shifted to designated compensating unit" shall equal the amount of compensating generation (in Kwh) that the designated representatives of the unit reducing utilization and the compensating unit have certified (in their respective annual compliance certification reports) as the amount that will be converted to mmBtus and subtracted, in accordance with paragraph (a)(4) of this section, from the adjusted utilization for the compensating unit.

(4) "Designated compensating generation provided to other units" is the total amount of utilization necessary to provide the generation that was shifted to the unit as a designated compensating unit under any other reduced utilization plans. This term equals the heat rate of such unit multiplied by the sum of the portion of each "generation shifted to designated compensating units" that is attributed to the unit in the annual compliance certification reports submitted by the Phase I units under such other plans and that is certified under paragraph (a)(3)(iv) of this section. If the unit filing the report is not a designated compensating unit under any other plans, this term is zero.

(5) Notwithstanding paragraphs (a)(3)(i) and (iii) of this section, where two or more Phase I units include in "plan reductions", in their annual compliance certification reports for the calendar year, estimated kilowatt hour savings from the same specific conservation measures or increased utilization of the same sulfur-free generator:

(i) The designated representatives of all such units shall submit with their annual reports a certification signed by all such designated representatives. The certification shall apportion the total kilowatt hour savings or increased utilization among such units.

(ii) Each designated representative shall include in its annual report only its share of the total savings or total increased utilization, in accordance with the certification under paragraph (a)(5)(i) of this section.

(6) Where a unit includes in "plan reductions" under paragraph (a)(3) of this section the increase in utilization of a sulfur-free generator that is not in the unit's dispatch system, the designated representative of the unit shall submit, with its annual compliance certification report, documentation demonstrating that an amount of electrical energy at least equal to the portion of the "shift to sulfur-free generators" attributed to the sulfur-free generator in the annual report was actually purchased by the unit's dispatch system from the sulfur-free generator.

(b) *Confirmation Report.* (1) If a unit's annual compliance certification report

estimates any expected kilowatt hour savings or improvement in heat rate from energy conservation or improved unit efficiency measures under a reduced utilization plan, the designated representative shall submit, by July 1 of the year in which the annual report was submitted, a confirmation report. The Administrator may grant, for good cause shown, an extension of the time to file the confirmation report. The confirmation report shall include the following elements in a format prescribed by the Administrator:

(i) The verified kilowatt hour savings from each such energy conservation measure and the verified corresponding reduction in the unit's heat input resulting from each measure during the calendar year covered by the annual report. For purposes of this paragraph (b), all values in Kwh shall be converted to mmBtu using the actual annual heat rate (Btu/Kwh) of the unit (determined in accordance with part 75 of this chapter) before the employment of any improved unit measures under an approved reduced utilization plan.

(ii) The verified reduction in the heat rate achieved by each improved unit efficiency measure and the verified corresponding reduction in the unit's heat input resulting from such measure.

(iii) For all figures under paragraphs (b)(1) (i) and (ii) of this section:

(A) Documentation (which may follow the EPA Conservation Verification Protocol) verifying specified figures to the satisfaction of the Administrator; or

(B) Certification, by a State utility regulatory authority that has ratemaking jurisdiction over the utility system that paid for the measures in accordance with § 72.43(b)(2) of this part and over rates reflecting any of the amount paid for such measures and that meets the criteria in § 73.82(c)(1) (i) and (ii) of this chapter, that such authority verified specified figures related to demand-side measures; and

(C) Certification, by a utility regulatory authority that has ratemaking jurisdiction over the utility system that paid for the measures in accordance with § 72.43(b)(2) of this part and over rates reflecting any of the amount paid for such measures, that such authority verified specified figures related to supply-side measures.

(2) Notwithstanding paragraph (b)(1)(i) of this section, where two or more Phase I units include in the confirmation report the verified kilowatt hour savings from the same specific conservation measures:

(i) The designated representatives of all such units shall submit with their confirmation reports a certification signed by all such designated representatives. The certification shall apportion the total kilowatt hour savings among such units.

(ii) Each designated representative shall include in its confirmation report only its share of the total savings in accordance with the certification under paragraph (b)(2)(i) of this section.

(3) If the total, included in the confirmation report, of the amounts of verified reduction in the unit's heat input from energy conservation and unit efficiency measures equals the total estimated in the unit's annual compliance certification report from such measures for the calendar year, then the designated representatives shall include in the confirmation report a statement indicating that is true.

(4) If the total, included in the confirmation report, of the amounts of verified reduction in the units's heat input from energy conservation and improved unit efficiency measures is greater than the total estimated in the unit's annual compliance certification report from such measures for the calendar year, then the designated representative shall include in the confirmation report the number of allowances to be credited to the unit's compliance subaccount calculated using the following formula:

Allowances credited=(verified heat input reduction-estimated hear input reduction) × emissions rate ÷ 2000 lbs/ton

where:

(i) "Verified heat input reduction" is the total of the amounts of verified reduction in the units' heat input (in mmBtu) from energy conservation and improved unit efficiency measures included in the confirmation report.

(ii) "Estimated heat input reduction" is the total of the amounts of reduction in the unit's heat input (in mmBtu) accounted for by energy conservation and improved efficiency measures as estimated in the unit's annual compliance certification report for the calendar year.

(iii) "Emissions rate" is the "emissions rate" under § 72.92(c)(2)(v) of this part.

(5) If the total, included in the confirmation report, of the amounts of verified reduction in the unit's heat input from energy conservation and improved unit efficiency measures is less than the total estimated in the unit's annual compliance certification report for such measures for the calendar year, then the designated representative shall include in the confirmation report the number of allowances to be deducted from the unit's compliance subaccount, which equals the absolute value of the result of the formula for allowances credited under paragraph (b)(4) of this section.

(6) Unless paragraph (b)(3) of this section applies, the designated representative shall include in the confirmation report the adjusted amount of allowances that would have held in the unit's compliance subaccount if the deductions made under § 73.35(b) of this chapter had been based on the verified, rather than the estimated, reduction in the unit's heat input from energy conservation and improved efficiency measures, calculated as follows:

Adjusted amount of allowances=allowances held after deduction–excess emissions + allowances credited–allowances deducted

where:

(i) "*Allowances held after deductions*" is the amount of allowances held in the unit's compliance subaccount after deductions were made under § 73.35(b) of this chapter based on the annual compliance certification report.

(ii) "*Excess emission*" is the amount (if any) of excess emissions determined under § 73.35(b) for the calendar year based on the annual compliance certification report.

(iii) "*Allowances credited*" is the amount of allowances calculated under paragraph (b)(4) of this section.

(iv) "*Allowances deducted*" is the amount of allowances calculated under paragraph (b)(5) of this section.

(v) If the result of the formula for "adjusted amount of allowances" is negative, the absolute value of the result constitutes excess emissions of sulfur dioxide. If the result is positive, there are no excess emissions of sulfur dioxide.

(7) If the amount of excess emissions of sulfur dioxide calculated under paragraph (b)(6) of this section differs from the amount of excess emissions of sulfur dioxide determined under § 73.35(b) of this chapter based on the annual compliance certification report, then the designated representative shall include in the confirmation report a demonstration of: the number of allowances that should be deducted to offset any increase in excess emissions or returned to account for any decrease in excess emissions; and the amount of the excess emissions penalty (excluding interest) that should be paid or returned to account for the change in excess emissions. The Administrator will deduct immediately from the unit's compliance subaccount the amount of allowances that he or she determines is

necessary to offset any increase in excess emissions or will return immediately to the unit's compliance subaccount the amount of allowances that he or she determines is necessary to account for any decrease in excess emissions. The designated representative may identify the serial numbers of the allowances to be deducted or returned. In the absence of such identification, the deduction will be on a first-in, first-out basis under § 73.35(c)(2) of this chapter and the return will be at the Administrator's discretion.

(8) If the designated representative of a unit fails to submit on a timely basis a confirmation report (in accordance with paragraph (b) of this section) with regard to the estimate of expected kilowatt hour savings or improvement in heat rate from any energy conservation or improved unit efficiency measure under the reduced utilization plan, then the Administrator will reject such estimate and correct it to equal zero in the unit's annual compliance certification report that includes that estimate. The Administrator will deduct immediately, on a first-in, first-out basis under § 73.35(c)(2) of this chapter, the amount of allowances that he or she determines is necessary to offset any increase in excess emissions of sulfur dioxide that results from the correction and require the owners and operators to pay an excess emission penalty in accordance with part 77 of this chapter.

§ 72.92 Phase I unit allowance surrender.

(a) *Annual Compliance Certification Report.* If a Phase I unit's adjusted utilization for the calendar year under § 72.91(a) is greater than zero, then the designated representative shall include in the annual compliance certification report the following elements:

(1) The number of allowances that shall be surrendered for adjusted utilization using the formula in paragraph (c) of this section and the calculations that were performed to obtain that number.

(2) Identification of the amounts of adjusted utilization that were caused by a dispatch-system-wide decline in sales, a forced outage at the unit, or economic dispatching in accordance with § 72.43(e)(1).

(3) If the unit experienced a forced outage during the year that is used to account for any adjusted utilization of the unit under paragraph (a)(2) of this section or if the unit is currently experiencing a forced outage that is expected to last longer than 4 months:

(i) A statement specifying the event that caused the forced outage;

(ii) The amount of adjusted utilization attributable to the forced outage (in mmBtu and Kwh), if any;

(iii) The duration or expected duration of the forced outage;

(iv) If the unit has not been returned to normal service, the expected date on which the unit will be returned to normal service; and

(v) A demonstration of the measures taken by the owners and operators to restore the unit to normal service as expeditiously as practicable, including any measures taken to prevent any similar forced outage in the future.

(b) *Other Submissions.*

(1) If a Phase I unit experienced a force outage during the calendar year that will cause the unit to shut down permanently and shift generation to any unit that would not otherwise be affected during Phase I, the designated representative shall submit to the Administrator within 60 days of the determination to shut down the unit permanently:

(i) A reduced utilization plan that designates one or more compensating units to which the unit will shift generation; or

(ii) A certification, from an independent auditor or a utility regulatory authority with ratemaking jurisdiction over any owner of the unit and over rates reflecting any capital or operating costs of the unit, that it is not possible to restore the unit to service at a reasonable cost.

(2)(i) If any Phase I unit in a dispatch system is governed during the calendar year by an approved reduced utilization plan relying on sulfur-free generation, then the designated representatives of all affected units in such dispatch system shall jointly submit, within 60 days of the end of the calendar year, a dispatch system data report that includes the following elements in a format prescribed by the Administrator:

(A) The name of the dispatch system as reported under § 72.33;

(B) The calculation of "percentage change in dispatch system sales" under § 72.91(a)(3)(iii)(C);

(C) A certification that each designated representative will use this figure, as appropriate, in its annual compliance certification report and will submit upon request the data supporting the calculation; and

(D) The signatures of all the designated representatives.

(ii) If any Phase I unit in a dispatch system has adjusted utilization greater than zero for the calendar year, then the designated representatives of all Phase I units in such dispatch system shall jointly submit, within 60 days of the end of the calendar year, a dispatch system data report that includes the following elements in a format prescribed by the Administrator:

(A) The name of the dispatch system as reported under § 72.33;

(B) The calculation of "percentage change in dispatch system sales" under § 72.91(a)(3)(iii)(C);

(C) The calculation of "dispatch system adjusted utilization" under paragraph (c)(2)(i) of this section;

(D) The calculation of "dispatch system aggregate baseline" under paragraph (c)(2)(ii) of this section;

(E) The calculation of "fraction of generation within dispatch system" under paragraph (c)(2)(v)(A) of this section;

(F) The calculation of "dispatch system emissions rate" under paragraph (c)(2)(v)(C) of this section;

(G) A certification that each designated representative will use these figures, as appropriate, in its annual compliance certification report and will submit upon request the data supporting these calculations; and

(H) The signatures of all the designated representatives.

(c) *Allowance Surrender Formula.* (1) As provided under the allowance surrender formula in paragraph (c)(2) of this section:

(i) Allowances are not surrendered for deduction for the portion of adjusted utilization accounted for by:

(A) Shifts in generation from the unit to other Phase I units;

(B) A dispatch-system-wide sales decline;

(C) Plan reductions under a reduced utilization plan as calculated under § 72.91; and

(D) Foreign generation.

(ii) Allowances are surrendered for deduction for the portion of adjusted utilization that is not accounted for under paragraph (c)(1)(i) of this section.

(2) The designated representative shall surrender for deduction the number of allowances calculated using the following formula:

Allowances surrendered = [dispatch system adjusted utilization + (dispatch system aggregate baseline × percentage change in dispatch system sales)] × unit's share × emissions rate ÷ 2000 lbs/ton.

If the result of the formula for "allowances surrendered" is less than or equal to zero, then no allowances are surrendered.

(i) *Calculating Dispatch System Adjusted Utilization.* "Dispatch system adjusted utilization" (in mmBtu) is the sum of the adjusted utilization under § 72.91(a) for all Phase I units in the dispatch system. If "dispatch system adjusted utilization" is less than or

equal to zero, then no allowances are surrendered by any unit in that dispatch system.

(ii) *Calculating Dispatch System Aggregate Baseline.* "Dispatch system aggregate baseline" is the sum of the baselines (as defined in § 72.2 of this chapter) for all Phase I units in the dispatch system.

(iii) *Calculating Percentage Change in Dispatch System Sales.* "Percentage change in dispatch system sales" is the "percentage change in dispatch system sales" under § 72.91 (a)(3)(iii)(C); *provided* that if result of the formula in § 72.91(a)(3)(iii)(C) is greater than or equal to zero, the value shall be treated as zero only for purposes of paragraph (c)(2) of this section.

(iv) *Calculating Unit's Share.* "Unit's share" is the unit's adjusted utilization divided by the sum of the adjusted utilization for all Phase I units within the dispatch system that have adjusted utilization of greater than zero and is calculated as follows:

$$\text{Unit's share} = \frac{U_{unit}}{\sum_{i=1}^{m} U_i}$$

where:

(A) U_{unit} = the unit's adjusted utilization for the calendar year;

(B) U_i = the adjusted utilization of a Phase I unit in the dispatch system for the calendar year; and

(C) m = all Phase I units in the dispatch system having an adjusted utilization greater than 0 for the calendar year.

(v) *Calculating Emissions Rate.* "Emissions rate" (in lbs./mmBtu) is the weighted average emissions rate for sulfur dioxide of all units, within and outside the dispatch system, that contributed to the dispatch system's electrical output for the year, calculated as follows:

Emissions rate = [fraction of generation within dispatch system × dispatch system emissions rate] + [fraction of generation outside dispatch system × fraction of non-Phase I and non-foreign generation in NERC region × NERC region average emissions rate]

where:

(A) "Fraction of generation within dispatch system" is the fraction of the dispatch system's total sales accounted for by generation from units within the dispatch system. This term equals the total generation (in Kwh) by all units and generators within the dispatch system for the calendar year divided by the total sales (in Kwh) by the dispatch system for the calendar year.

(B) "Fraction of generation outside dispatch system" = 1 – fraction of generation within dispatch system.

(C) "Dispatch system emissions rate" is the weighted average rate (in lbs/mmBtu) for the dispatch system calculated as follows:

$$\text{Dispatch system emissions rate} = \sum_{i=1}^{k} g_i r_i \div \sum_{i=1}^{k} g_i$$

where:

g_i = a Phase II unit's utilization for the calendar year

r_i = a Phase II unit's emission rate, determined in accordance with part 75 of this chapter, for the calendar year

k = number of Phase II units in the dispatch system

(D) "Fraction of non-Phase I and non-foreign generation in NERC region" is the portion of the NERC region's total sales generated by units other than Phase I units or foreign sources in the unit's NERC region in 1985, as set forth in Table 1 of this section.

(E) "NERC region average emissions rate" is the weighted average emissions rate (in lbs/mmBtu) for the unit's NERC region in 1985, as set forth in Table 1 of this section.

TABLE 1.—NERC REGION GENERATION AND EMISSIONS RATE IN 1985

NERC region	Fraction of non-phase I and non-foreign generation in NERC region	NERC weighted average emissions rate (lb/mmBtu)
WSCC	1.000	0.466
SPP	0.940	0.647
SERC	0.662	1.315
NPCC	0.864	1.058
MAPP	0.946	1.171
MAIN	0.577	1.495
MAAC	0.683	1.599
ERCOT	1.000	0.491
ECAR	0.541	1.564

§ 72.93 Units with Phase I extension plans.

Annual Compliance Certification Report. The designated representative for a control unit governed by a Phase I extension plan shall include in the unit's annual compliance certification report for calendar year 1997, the start-up test results upon which the vendor is released from liability under the vendor certification of guaranteed sulfur dioxide removal efficiency under § 72.42(c)(12).

§ 72.94 Units with repowering extension plans.

(a) *Design and Engineering and Contract Requirements.* No later than January 1, 2000, the designated representative of a unit governed by an approved repowering plan shall submit to the Administrator and the permitting authority:

(1) Satisfactory documentation of a preliminary design and engineering effort.

(2) A binding letter agreement for the executed and binding contract (or for each in a series of executed and binding contracts) for the majority of the equipment to repower the unit using the technology conditionally approved by the Administrator under § 72.44(d)(3).

(3) The letter agreement under paragraph (a)(2) of this section shall be signed and dated by each party and specify:

(i) The parties to the contract;

(ii) The date each party executed the contract;

(iii) The unit to which the contract applies;

(iv) A brief list identifying each provision of the contract;

(v) Any dates to which the parties agree, including construction completion date;

(vi) The total dollar amount of the contract; and

(vii) A statement that a copy of the contract is on site at the source and will be submitted upon written request of the Administrator or the permitting authority.

(b) *Removal From Operation to Repower.* The designated representative of a unit governed by an approved repowering plan shall notify the Administrator in writing at least 60 days in advance of the date on which the existing unit is to be removed from operation so that the qualified repowering technology can be installed, or is to be replaced by another unit with the qualified repowering technology, in accordance with the plan.

(c) *Commencement of Operation.* Not later than 60 days after the units repowered under an approved repowering plan commences operation at full load, the designated representative of the unit shall submit a report comparing the actual hourly emissions and percent removal of each pollutant controlled at the unit to the actual hourly emissions and percent removal at the existing unit under the plan prior to repowering, determined in accordance with part 75 of this chapter.

(d) *Decision to Terminate.* If at any time before the end of the repowering extension the owners and operators decide to terminate good faith efforts to design, construct, and test the qualified repowering technology on the unit to be repowered under an approved repowering plan, then the designated

representative shall submit a notice to the Administrator by the earlier of the end of the repowering extension or a date within 30 days of such decision, stating the date on which the decision was made.

§ 72.95 Allowance deduction formula.

The following formula shall be used to determine the total number of allowances to be deducted for the calendar year from the allowances held in an affected unit's compliance subaccount as of the allowance transfer deadline applicable to that year:

Total allowances deducted=Tons emitted + Allowances surrendered for underutilization+Allowances deducted for Phase I extensions

where:

(a) "Tons emitted" is the total tons of sulfur dioxide emitted by the unit during the calendar year, as reported in accordance with part 75 of this chapter.

(b) "Allowances surrendered for underutilization" is the total number of allowances calculated in accordance with § 72.92 (a) and (c).

(c) "Allowances deducted for Phase I extensions" is the total number of allowances calculated in accordance with § 72.42(f)(1)(i).

§ 72.96 Administrator's action on compliance certifications.

(a) The Administrator may review, and conduct independent audits concerning, any compliance certification and any other submission under the Acid Rain Program and make appropriate adjustments of the information in the compliance certifications and other submissions.

(b) The Administrator may deduct allowances from or return allowances to a unit's Allowance Tracking System account in accordance with part 73 of this chapter based on the information in the compliance certifications and other submissions, as adjusted.

Appendix A to Part 72—Methodology for Annualization of Emissions Limits

For the purposes of the Acid Rain Program, 1985 emissions limits must be expressed in pounds of SO_2 per million British Thermal Unit of heat input (lb/mmBtu) and expressed on an annual basis.

Annualization factors are used to develop annual equivalent SO_2 limits as required by § 402(18) of the CAA. Many emission limits are enforced on a shorter term basis (or averaging period) than annually. Because of the variability of sulfur in coal and, in some cases, scrubber performance, meeting a particular limit with an averaging period of less than a year and at a specified statutory emissions level would require a lower annual average SO_2 emission rate (or annual equivalent SO_2 limit) than would the shorter term statutory limit. EPA has selected a compliance level of one exceedance per 10 years. For example, an SO_2 emission limit of 1.2 lbs/MMBtu, enforced for a scrubbed unit over a 7-day averaging period, would result in an annualized SO_2 emission limit of 1.16 lbs/MMBtu. In general, the shorter the averaging period, the lower the annual equivalent would be. Thus, the annualization of limits is established by multiplying each federally enforceable limit by an annualization factor that is determined by the averaging period and whether or not it's a scrubbed unit.

TABLE A–1.—SO_2 EMISSION AVERAGING PERIODS AND ANNUALIZATION FACTORS

Definition	Annualization factor	
	Scrubbed unscrubbed	
	Unit	Unit
Oil/gas unit	1.00	1.00
<=1 day	0.93	0.89
1 week	0.97	0.92
30 days	1.00	0.96
90 days	1.00	1.00
1 year	1.00	1.00
Not specified	0.93	0.89
At all times	0.93	0.89
Coal unit: No Federal limit or limit unknown	1.00	1.00

Appendix B to Part 72—Methodology for Conversion of Emissions Limits

For the purposes of the Acid Rain Program, all emissions limits must be expressed in pounds of SO_2 per million British Thermal Unit of heat input (lb/mmBtu).

The factor for converting pounds of sulfur to pounds of SO_2 is based on the molecular weights of sulfur (32) and SO_2 (64). Limits expressed as percentage of sulfur or parts per million (ppm) depend on the energy content of the fuel and thus may vary, depending on several factors such as fuel heat content and atmospheric conditions. Generic conversions for these limits are based on the assumed average energy contents listed in Table A–2. In addition, limits in ppm vary with boiler operation (e.g., load and excess air); generic conversions for these limits assume, conservatively, very low excess air. The remaining factors are based on site-specific heat rates and capacities to develop conversions for Btu per hour. Standard conversion factors for residual oil are 42 gal/bbl and 7.88 lbs/gal.

TABLE B–1.—CONVERSION FACTORS

[Emission limits converted to lbs SO_2/MMBtu by multiplying as below]

Unit measurement	Plant fuel type			
	Bituminous coal	Subbituminous coal	Lignite coal	Oil
Lbs sulfur/MMBtu	2.0	2.0	2.0	2.0
% sulfur in fuel	1.66	2.22	2.86	1.07
Ppm SO_2	0.00287	0.00384	.....	0.00167
Ppm sulfur in fuel	.....	.....	.....	0.00334
Tons SO_2/hour	2,000,000/(HEATRATE*SUMNDCAP*capacity factor)[1]			
Lbs SO_2/hour	1,000/(HEATRATE*SUMNDCAP*capacity factor)[1]			

[1] In these cases, if the limit was specified as the "site" limit, the summer net dependable capability for the entire plant is used; otherwise, the summer net dependable capability for the unit is used. For units listed in the NADB, "HEATRATE" shall be that listed in the NADB under that field and "SUMNDCAP" shall be that listed in the NADB under that field. For units not listed in the NADB, "HEATRATE" is the generator net full load heat rate reported on Form EIA–860 and "SUMNDCAP" is the summer net dependable capability of the generator (in MWe) as reported on Form EIA–860.

TABLE B–2.—ASSUMED AVERAGE ENERGY CONTENTS

Fuel type	Average heat content
Bituminous Coal	24 MMBtu/ton.
Subbituminous Coal	18 MMBtu/ton.
Lignite Coal	14 MMBtu/ton.
Residual Oil	6.2 MMBtu/bbl.

Appendix C to Part 72—Actual 1985 Yearly SO_2 Emissions Calculation

The equation used to calculate the yearly SO_2 emissions (SO2) is as follows:

SO2 = (coal SO_2 emissions) + (oil SO_2 emissions) (in tons)

If gas is the only fuel, gas emissions are defaulted to 0.

Each fuel type SO_2 emissions is calculated on a yearly basis, using the equation:

fuel SO_2 emissions (in tons) = (yrly wtd. av. fuel sulfur %) × (AP–42 fact.) × (1–scrb. effic. %/100) × (units conver. fact.) × (yearly fuel burned)

For coal, the yearly fuel burned is in tons/yr and the AP–42 factor (which accounts for the ash retention of sulfur in coal), in lbs SO_2 ton coal, is by coal type:

Coal type	AP–42 factor
Bituminous, anthracite	39 lbs/ton
Subbituminous	35
Lignite	30

For oil, the yearly fuel burned is in gal/yr. If it is in bbl/yr, convert using 42 gal/bbl oil. The AP–42 factor (which accounts for the oil density), in lbs SO_2/thousand gal oil, is by oil type:

Oil type	AP–42 factor
Distillate (light)	142 lbs/1,000 gal
Residual (heavy)	157

For all fuel, the units conversion factor is 1 ton/2000 lbs.

2. The authority citation for part 73 continues to read as follows:

Authority: 42 U.S.C. 7651.

3. Part 73 is amended by revising subpart A and by adding subparts B through D to read as follows:

PART 73—ALLOWANCE SYSTEM

Subpart A—Background and Summary

Sec.
73.1 Purpose and scope.
73.2 Applicability.
73.3 General.

Subpart B—Allowance Allocations

73.10 Initial allocations for Phase I.
73.25 Phase I extension reserve.
73.27 Special allowance reserve.

Subpart C—Allowance Tracking System

73.30 Allowance tracking system accounts.
73.31 Establishment of accounts.
73.32 Allowance account contents.
73.33 Authorized account representative.
73.34 Recordation in accounts.
73.35 Compliance.
73.36 Banking.
73.37 Account error and dispute resolution.
73.38 Closing of accounts.

Subpart D—Allowance Transfers

73.50 Scope and submission of transfers.
73.51 Prohibition.
73.52 EPA recordation.
73.53 Notification.

Subpart A—Background and Summary

§ 73.1 Purpose and scope.

The purpose of this Part is to establish the requirements and procedures for the following:

(a) The allocation of sulfur dioxide emissions allowances;

(b) The tracking, holding, and transfer of allowances;

(c) The deduction of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to parts 72 and 77 of this chapter;

(d) The sale of allowances through EPA-sponsored auctions and a direct sale, including the independent power producers written guarantee program; and

(e) The application for, and distribution of, allowances from the Conservation and Renewable Energy Reserve.

§ 73.2 Applicability.

The following parties shall be subject to the provisions of this Part:

(a) Owners, operators, and designated representatives of affected sources and affected units pursuant to § 72.6 of this chapter;

(b) Any new independent power producer as defined in section 416 of the Act and § 72.2 of this chapter, except as provided in section 405(g)(6) of the Act;

(c) Any owner of an affected unit who may apply to receive allowances under the Energy Conservation and Renewable Energy Reserve Program established in accordance with section 404(f) of the Act;

(d) Any small diesel refinery as defined in § 72.2 of this chapter, and

(e) Any other person, as defined in § 72.2 of this chapter, who chooses to purchase, hold, or transfer allowances as provided in section 403(b) of the Act.

§ 73.3 General.

Part 72 of this chapter, including §§ 72.2 (definitions), 72.3 (measurements, abbreviations, and acronyms), 72.4 (Federal authority), 72.5 (State authority), 72.6 (applicability), 72.7 (new units exemption), 72.8 (retired unit exemption), 72.9 (standard requirements), 72.10 (availability of information), and 72.11 (computation of time) of part 72, subpart A of this chapter, shall apply to this part. The procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter. Sections 73.3 (Definitions) and 73.4 (Deadlines), which were previously published with subpart E of this part—"Auctions, Direct Sales, and Independent Power Producers Written Guarantee", are codified at §§ 72.2 and 72.12 of this chapter, respectively.

Subpart B—Allowance Allocations

§ 73.10 Initial allocations for Phase I.

(a) *Phase I Allowances.* The Administrator will allocate allowances to the unit account for each unit listed in Table 1 of this section in the amount listed in Column A to be held in each future year subaccount for the years 1995 through 1999.

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
Alabama	Colbert	1	13213	357
		2	14907	403
		3	14995	405
		4	15005	405
		5	36202	978
	E.C. Gaston	1	17624	476
		2	18052	488
		3	17828	482

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS—Continued

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
		4	18773	507
		5	58265	1575
Florida	Big Bend	BB01	27662	748
		BB02	26387	713
		BB03	26036	704
	Crist	6	18695	505
		7	30846	834
Georgia	Bowen	1BLR	54838	1482
		2BLR	53329	1441
		3BLR	69862	1888
		4BLR	69852	1888
	Hammond	1	8549	231
		2	8977	243
		3	8676	234
		4	36850	990
	Jack McDonough	MB1	19386	524
		MB2	20058	542
	Wansley	1	68908	1862
		2	63708	1722
	Yates	Y1BR	7020	190
		Y2BR	6855	185
		Y3BR	6767	183
		Y4BR	8676	234
		Y5BR	9162	248
		Y6BR	24108	652
		Y7BR	20915	565
Illinois	Baldwin	1	46052	1245
		2	48695	1316
		3	46644	1261
	Coffeen	01	12925	349
		02	39102	1057
	Grand Tower	09	6479	175
	Hennepin	2	20182	545
	Joppa Steam	1	12259	331
		2	10487	283
		3	11947	323
		4	11061	299
		5	11119	301
		6	10341	279
	Kincaid	1	34565	934
		2	37063	1002
	Meredosia	05	15227	411
	Vermilion	2	9735	263
Indiana	Bailly	7	12256	331
		8	17134	463
	Breed	1	20280	548
	Cayuga	1	36581	989
		2	37415	1011
	Clifty Creek	1	19620	530
		2	19289	521
		3	19873	537
		4	19552	528
		5	18851	509
		6	19844	536
	Elmer W. Stout	50	4253	115
		60	5229	141
		70	25883	699
	F.B. Culley	2	4703	127
		3	18603	503
	Frank E. Ratts	1SG1	9131	247
		2SG1	9296	251
	Gibson	1	44288	1197
		2	44956	1215
		3	45033	1217
		4	44200	1195
	H.T. Pritchard	6	6325	171
	Michigan City	12	25553	691
	Petersburg	1	18011	487
		2	35496	959
	R. Gallagher	1	7115	192
		2	7980	216
		3	7159	193
		4	8396	227
	Tanners Creek	U4	27209	735
	Wabash River	1	4385	118
		2	3135	85
		3	4111	111
		5	4023	109
		6	13462	364

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS—Continued

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
	Warrick	4	29577	799
Iowa	Burlington	1	10428	282
	Des Moines	11	2259	61
	George Neal	1	2571	69
	Milton L. Kapp	2	13437	363
	Prairie Creek	4	7965	215
	Riverside	9	3885	105
Kansas	Quindaro	2	4109	111
Kentucky	Coleman	C1	10954	296
		C2	12502	338
		C3	12015	325
	Cooper	1	7254	196
		2	14917	403
	E.W. Brown	1	6923	187
		2	10623	287
		3	25413	687
	Elmer Smith	1	6348	172
		2	14031	379
	Ghent	1	27662	748
	Green River	5	7614	206
	H.L. Spurlock	1	22181	599
	HMP&L Station 2	H1	12989	351
		H2	11986	324
	Paradise	3	57613	1557
	Shawnee	10	9902	268
Maryland	C.P. Crane	1	10058	272
		2	8987	243
	Chalk Point	1	21333	577
		2	23690	640
	Morgantown	1	34332	928
		2	37467	1013
Michigan	J.H. Campbell	1	18773	507
		2	22453	607
Minnesota	High Bridge	6	4158	112
Mississippi	Jack Watson	4	17439	471
		5	35734	966
Missouri	Asbury	1	15764	426
	James River	5	4722	128
	LaBadie	1	39055	1055
		2	36718	992
		3	39249	1061
		4	34994	946
	Montrose	1	7196	194
		2	7984	216
		3	9824	266
	New Madrid	1	27497	743
		2	31625	855
	Sibley	3	15170	410
	Sioux	1	21976	594
		2	23067	623
	Thomas Hill	MB1	9980	270
		MB2	18880	510
New Hampshire	Merrimack	1	9922	268
		2	21421	579
New Jersey	B.L. England	1	8822	238
		2	11412	308
New York	Dunkirk	3	12268	332
		4	13690	370
	Greenidge	6	7342	198
	Milliken	1	10876	294
		2	12083	327
	Northport	1	19289	521
		2	23476	634
		3	25783	697
	Port Jefferson	3	10194	276
		4	12006	324
Ohio	Ashtabula	7	18351	496
	Avon Lake	11	12771	345
		12	33413	903
	Cardinal	1	37568	1015
		2	42008	1135
	Conesville	1	4615	125
		2	5360	145
		3	6029	163
		4	53463	1445
	Eastlake	1	8551	231
		2	9471	256
		3	10984	297
		4	15906	430

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS—Continued

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
		5	37349	1009
	Edgewater	13	5536	150
	Gen. J.M. Gavin	1	86690	2343
		2	88312	2387
	Kyger Creek	1	18773	507
		2	18072	488
		3	17439	471
		4	18218	492
		5	18247	493
	Miami Fort	5–1	417	11
		5–2	417	11
		6	12475	337
		7	42216	1141
	Muskingum River	1	16312	441
		2	15533	420
		3	15293	413
		4	12914	349
		5	44364	1199
	Niles	1	7608	206
		2	9975	270
	Picway	9	5404	146
	R.E. Burger	5	3371	91
		6	3371	91
		7	11818	319
		8	13626	368
	W.H. Sammis	5	26496	716
		6	43773	1183
		7	47380	1280
	Walter C. Beckjord	5	9811	265
		6	25235	682
Pennsylvania	Armstrong	1	14031	379
		2	15024	406
	Brunner Island	1	27030	730
		2	30282	818
		3	52404	1416
	Cheswick	1	38139	1031
	Conemaugh	1	58217	1573
		2	64701	1749
	Hatfield's Ferry	1	36835	995
		2	36338	982
		3	39210	1060
	Martins Creek	1	12327	333
		2	12483	337
	Portland	1	5784	156
		2	9961	269
	Shawville	1	10048	272
		2	10048	272
		3	13846	374
		4	13700	370
	Sunbury	3	8530	230
		4	11149	301
Tennessee	Allen	1	14917	403
		2	16329	441
		3	15258	412
	Cumberland	1	84419	2281
		2	92344	2496
	Gallatin	1	17400	470
		2	16855	455
		3	19493	527
		4	20701	559
	Johnsonville	1	7585	205
		10	7351	199
		2	7828	212
		3	8189	221
		4	7780	210
		5	8023	217
		6	7682	208
		7	8744	236
		8	8471	229
		9	6894	186
West Virginia	Albright	3	11684	316
	Fort Martin	1	40496	1094
		2	40116	1084
	Harrison	1	47341	1279
		2	44936	1214
		3	40408	1092
	Kammer	1	18247	493
		2	18948	512
		3	16932	458

TABLE 1.—PROPOSED PHASE I ALLOWANCE ALLOCATIONS—Continued

State name	Plant name	Boiler	Column A final phase 1 allocation	Column B auction and sales reserve
Wisconsin	Mitchell	1	42823	1157
		2	44312	1198
	M.T. Storm	1	42570	1150
		2	34644	936
		3	41314	1116
	Edgewater	4	24099	651
	Genoa	1	22103	597
	Nelson Dewey	1	5852	158
		2	6504	176
	North Oak Creek	1	5083	137
		2	5005	135
		3	5229	141
		4	6154	166
	Pulliam	8	7312	198
	South Oak Creek	5	9416	254
		6	11723	317
		7	15754	426
		8	15375	415

(b) [Reserved]

§ 73.25 Phase I extension reserve.

The Administrator will initially allocate 3.5 million allowances to the Phase I Extension Reserve account of the Allowance Tracking System. Allowances from this Reserve will be allocated to units under § 72.42 of this chapter. Allowances remaining in the Phase I Extension Reserve account following allocation of all extension allowances under § 72.42 of this chapter will remain in the Reserve.

§ 73.27 Special allowance reserve.

(a) *Establishment of Reserve.* (1) The Administrator will allocate 150,000 allowances annually for calendar years 1995 through 1999 to the Auction Subaccount of the Special Allowance Reserve.

(b) *Distribution of Proceeds.* Monetary proceeds from the auctions and sales of allowances from the Special Allowance Reserve (under subpart E of this part) for use in calendar years 1995 through 1999 will be distributed to the designated representative of the unit according to the following equation:

unit proceeds=(Column B of Table 1 of section 73.10/150,000) × total proceeds

(c) *Reallocation of Allowances.* Allowances remaining in the Special Allowance Reserve following the annual auctions and sales (under subpart E of this part) for use in calendar years 1995 through 1999 will be reallocated to the unit's Allowance Tracking System Account according to the following equation:

unit allowances = (Column B of Table 1 of section 73.10/150,000) × Allowances remaining

(d) *Calculation Rounding.* All proceeds under this section shall be distributed as whole dollars. All calculations for such allowances shall be rounded down for decimals less than .5 and up for decimals of .5 or greater.

(e) *Achieving Exact Totals.* (1) If the sum of the proceeds to be distributed under paragraph (b) of this section exceeds the total proceeds or the allowances to be reallocated under paragraph (c) of this section exceeds the allowances remaining, then the Administrator will withdraw one dollar or allowance from each unit, beginning with the unit receiving the largest number of dollars or allowances, in descending order, until the distribution balances with the proceeds and the reallocated allowances balance with the remaining allowances.

(2) If the sum of the proceeds to be distributed under paragraph (b) of this section is less than the total proceeds or the allowances to be reallocated under paragraph (c) of this section is less than the allowances remaining, then EPA will distribute one dollar or allowance for each unit, beginning with the unit receiving the largest number of dollars or allowances, in descending order, until the distribution balances with the proceeds and the reallocated allowances balance with the remaining allowances.

Subpart C—Allowance Tracking System

§ 73.30 Allowance tracking system accounts.

(a) *Nature and function of unit accounts.* The Administrator will establish accounts for all affected units pursuant to § 73.31 (a) and (b). All allocations of allowances pursuant to subparts B, E, and F of this part and part 72 of this chapter, transfers of allowances made pursuant to subparts C and D, and deductions of allowances made for purposes of offsetting emissions pursuant to § 73.35 (b) and (d) and parts 72, 75, and 77 of this chapter will be reordered in the unit's Allowance Tracking System account.

(b) *Nature and function of general accounts.* Transfers of allowances held for any person other than an affected unit, made pursuant to subparts C, D, E, F, and G of this part will be recorded in that person's Allowance Tracking System account established pursuant to § 73.31(c).

§ 73.31 Establishment of accounts.

(a) *Existing affected units.* The Administrator will establish an Allowance Tracking System account and allocate allowances for each unit that is, or will become, an existing affected unit pursuant to sections 404(a) or 405 of the Act and § 72.6 of this chapter.

(b) *New units.* Upon receipt of a complete certificate of representation for the designated representative for a new unit pursuant to part 72, subpart B of this chapter, the Administrator will establish an Allowance Tracking System account for the unit.

(c) *General accounts.* (1) Any person may apply to open an Allowance Tracking System account for the purpose of holding and transferring allowances. Such application shall be submitted to the Administrator in a format to be specified by the Administrator by means of the General Allowance Account Information Form, or by providing the following information in a similar format:

(i) Name and title of the authorized account representative and alternate

authorized account representative (if any) pursuant to § 73.33;

(ii) Mailing address, telephone number and facsimile transmission number (if any) of the authorized account representative and alternate authorized account representative (if any);

(iii) Organization or company name (if applicable) and type of organization (if applicable);

(iv) A list of all persons subject to a binding agreement for the authorized account representative to represent their ownership interest with respect to the allowances held in the general account and which shall be amended and resubmitted within 30 days following any transaction giving rise to any change of the list of persons subject to the binding agreement;

(v) A certification statement by the authorized account representative and alternate authorized account representative (if any) that reads "I certify that I was selected under the terms of an agreement that is binding on all persons who have an ownership interest with respect to allowances held in the Allowance Tracking System account. I certify that I have all necessary authority to carry out my duties and responsibilities on behalf of the persons with an ownership interest and that they shall be fully bound by my actions, inactions, or submissions under 40 CFR part 73. I shall abide by any fiduciary responsibilities assigned pursuant to the binding agreement. I am authorized to make this submission on behalf of the persons with an ownership interest for whom this submission is made. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false material information, or omitting material information, including the possibility of fine or imprisonment for violations.";

(vi) The signature of the authorized account representative and the alternate authorized account representative (if any); and

(vii) The date of the signature of the authorized account representative and the alternate authorized account representative (if any).

(2) Upon receipt of such complete application, the Administrator will establish an Allowance Tracking System account for the person or persons identified in the application.

(3) No allowance transfers will be recorded for a general account until the Administrator has established the new account.

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established pursuant to this section.

§ 73.32 Allowance account contents.

Each allowance account will include, at a minimum, the following:

(a) The name, address, telephone number and facsimile transmission number, if any, of the authorized account representative; and

(1) In the case of a unit account, a list of all persons identified as owners of record of the unit in § 72.25(a)(3) of this chapter, or

(2) In the case of a general account, a list of all persons subject to the binding agreement for the authorized account representative to represent their ownership interest with respect to allowances, as identified in accordance with § 73.31(c);

(b) A list of transfers of allowances to, and from, the account, including the identity of the transferror and transferee accounts;

(c) In the case of a unit account for an existing affected unit, beginning in 1995, a compliance subaccount;

(d) In the case of a unit account for a new unit, a compliance subaccount;

(e) In the case of a general account, a current year subaccount;

(f) Future year subaccounts for each of the 30 calendar years following the later of 1995 or the current calendar year;

(g) In the case of a unit account, the current total of sulfur dioxide emissions in tons for the current calendar year as reported to date pursuant to part 75 of this chapter.

§ 73.33 Authorized account representative.

(a) Following the establishment of an Allowance Tracking System account, all matters pertaining to the account, including, but not limited to, the deduction and transfer of allowances in the account, shall be undertaken only by the authorized account representative.

(b) *Authorized account representative identification.* The Administrator will assign a unique identifying number to each authorized account representative or alternate authorized account representative identified pursuant to § 73.31(c).

(c) *Notification of parties subject to the binding agreement.* The authorized account representative for a general account shall notify, in writing, all persons who have an ownership interest with respect to the allowances held in the account of any Acid Rain Program submission required by this part or in a procedure under part 78 of this chapter, by the date of submission. Each person who has an ownership interest with respect to the allowances held in the account may expressly waive his or her right to receive such notification.

(d) *General account alternate authorized account representative.* Any application for opening a general account may designate one alternate authorized account representative to act on behalf of the certifying authorized account representative, in the event the authorized account representative is absent or otherwise not available to perform actions and duties under this part. The alternate shall be a natural person and shall be authorized, provided that the conditions and procedures specified in § 73.31(c)(1) are met.

(1) The alternate authorized account representative may be changed at any time by the authorized account representative upon receipt by the Administrator of a new complete application as required in § 73.31(c);

(2) The alternate authorized account representative shall be subject to the provisions of this part applicable to authorized account representatives;

(3) Whenever the term "authorized account representative" is used in this part it shall be construed to include the alternate authorized account representative, unless such a construction would be illogical from the context; and

(4) Any action, representation or failure to act by the alternate authorized account representative when acting in that capacity shall be deemed to be an action of the authorized account representative, with all the rights, duties, and responsibilities pertaining thereto.

(e) *Changes to the general account authorized account representative.* An authorized account representative for a general account may be succeeded by any person who submits an application pursuant to § 73.31(c). The actions of an authorized account representative for a general account shall be binding on any successor.

(f) *Objections to the authorized account representative.* Except for a certification pursuant to paragraph (e) of this section, no objection or other communication submitted to the Administrator concerning any submission to the Administrator by the authorized account representative shall affect the recordation of transfers submitted by the authorized account representative pursuant to subpart D of

this part. Neither the United States, the Administrator, nor any permitting authority will adjudicate any dispute between and among persons concerning any submission to the Administrator by the authorized account representative; any actions of the authorized account representative; or any other matter arising directly or indirectly from the certification, actions or representations of the authorized account representative.

§ 73.34 Recordation in accounts.

(a) *Recordation in compliance subaccounts.* At the beginning of 1995 and, in the case of each year thereafter, after the Administrator has made all deductions from an affected unit's compliance subaccount pursuant to § 73.35(b), the Administrator will record in the compliance subaccount the allowances held in the future year subaccount for the year corresponding to the current calendar year. The future year subaccount for the new 30th year will be established at the same time and include the allowances allocated for the unit for that year pursuant to subpart B of this part.

(b) *Recordation in current year subaccounts.* At the beginning of 1995 and each year thereafter, the Administrator will record in the current year subaccount the allowances held in the future year subaccount for the year corresponding to the current calendar year.

(c) *Recordation in subaccounts.* Allowances in each compliance, current year, and future year subaccounts will reflect:

(1) All allowances allocated or deducted for the unit for the year pursuant to subpart B of this part;

(2) All allowances allocated or deducted pursuant to § 72.41, § 72.42, § 72.43, and § 72.44 of this chapter;

(3) All allowances allocated pursuant to subparts F and G of this part;

(4) All allowances recorded as a result of purchases or returns from the annual auctions or direct sale pursuant to subpart E of this part;

(5) All allowances recorded or deducted as a result of allowance transfers recorded pursuant to subpart D of this part; and

(6) All allowances deducted or returned pursuant to § 73.35(d), §§ 72.91 and 72.92, and part 77 of this chapter.

(d) *Serial numbers for allocated allowances.* Upon the allocation of allowances to an account, including allowances contained in reserves as provided in subpart B of this part, the Administrator will assign each allowance a unique identification number that will include digits identifying the allowance's compliance use date.

§ 73.35 Compliance.

(a) *Allowance transfer deadline.* No allowance shall be deducted for purposes of compliance with an affected unit's sulfur dioxide Acid Rain emissions limitation requirements pursuant to title IV of the Act and paragraph (b) of this section unless:

(1) The compliance use date of the allowance is no later than the year in which the unit's SO_2 emissions occurred; and

(2) Such allowance is recorded in the compliance subaccount, or its transfer to the unit's compliance subaccount is submitted correctly pursuant to subpart D for recordation in the compliance subaccount for the unit by not later than the allowance transfer deadline of January 30 of the calendar year following the year for which compliance is being established in accordance with the requirements of subpart D of this part.

(b) *Deductions for compliance.* (1) Except as provided in paragraph (d) of this section, following the recordation of transfers submitted correctly pursuant to subpart D for recordation in the compliance subaccount pursuant to paragraph (a) of this section and subpart D of this part, the Administrator will deduct allowances from each affected unit's compliance subaccount in accordance with the allowance deduction formula in § 72.95 of this chapter and any correction made under § 72.96 of this chapter.

(2) The Administrator will make deductions until either the number of allowances deducted is equal to the amount calculated in accordance with § 72.95 of this chapter, as modified under § 72.96 of this chapter or until no more allowances remain in the compliance subaccount.

(c)(1) *Identification of allowances by serial number.* By no later than sixty days after the end of the calendar year, the authorized account representative for each unit account may identify by serial number the allowances to be deducted from the compliance subaccount for purposes of compliance with the unit's sulfur dioxide emissions limitation requirements. Such identification shall be made pursuant to part 72 of this chapter.

(2) *First-in, first-out.* In the absence of an identification or in the case of a partial identification of allowances by serial number, as provided for in paragraph (b)(1) or (d) of this section, the Administrator will deduct allowances on a first-in, first-out (FIFO) accounting basis beginning with those allowances with the earliest compliance use date originally allocated for the unit and recorded in its compliance subaccount. Following the deduction of all originally allocated allowances from the compliance subaccount, the Administrator will deduct those allowances that were transferred and recorded in the unit's compliance subaccount pursuant to subpart D of this part, beginning with those with the earliest date of recordation.

(d) *Deductions for excess emissions.* Pursuant to § 77.4 of this chapter, and following the process of recordation set forth in § 73.34(a) of this part, the Administrator will deduct allowances for each unit with excess emissions for the preceding calendar year in an amount equal to the unit's excess emissions tonnage.

(e) *Deductions for units sharing a common emission stack.* In the case of units sharing a common emission stack and have emissions that are not individually monitored pursuant to part 75 of this chapter, the authorized account representative may identify the percentage of allowances to be deducted from each unit's compliance subaccount. Such identification shall be made pursuant to part 72, subpart I of this chapter. In the absence of an identification, the Administrator will deduct an equal percentage of allowances from each unit's compliance subaccount.

§ 73.36 Banking.

(a) *Unit accounts.* Any allowance in a compliance subaccount not deducted pursuant to § 73.35 will remain in the compliance subaccount.

(b) *General accounts.* In the case of a general account, any allowances in the current year subaccount at the end of the current calendar year will remain in the current year subaccount.

§ 73.37 Account error and dispute resolution.

(a) *Claim of error.* The authorized account representative may notify the Administrator of any claim that the Administrator made an error in recording transfer information that was submitted correctly pursuant to subpart D of this part, provided that such claim of error notification is submitted to the Administrator by no later than 15 business days following the date mark of the notification by the Administrator pursuant to actions taken under § 73.37(d) or § 73.53. Such claim of error notification shall be in writing and shall include:

(1) A description of the error alleged to have been made by the Administrator;

(2) A proposed correction of the alleged error;

(3) Any supporting documentation or other information concerning the alleged error and proposed correction; and

(4) Certification by the signature of and the date of the signature of the authorized account representative.

The Administrator will not act on claim of error notifications received after the stated deadlines (except as provided under paragraph (f) of this section, or that do not contend that the Administrator made an error in recordation.

(b) *EPA action.* The Administrator, at the Administrator's sole discretion based on documentation provided, will determine what changes, if any, will be made to the accounts subject to the alleged error. Not later than 20 business days after receipt of a claim of error notification pursuant to paragraph (a) of this section, the Administrator will submit to the authorized account representative a written response stating:

(1) The determination made and any action taken by, the Administrator; and

(2) The reasons for such action.

(c) *Administrative Appeals Procedure.* Following the Administrator's action pursuant to paragraph (b) of this section, the authorized account representative may appeal the Administrator's action through the administrative appeals procedure pursuant to part 78 of this chapter.

(d) *EPA corrections.* The Administrator may, without prior notice of a claim of error and in the Administrator's sole discretion, correct any errors in any account on his or her own motion. The Administrator will notify the authorized account representative by no later than 20 business days following any such corrections.

(e) *Excess Emissions Requirements.* The filing of a claim of error notification pursuant to paragraph (a) of this section, or the pendency of the Administrator's action pursuant to paragraph (b) of this section, shall not affect a unit's obligations under part 77 of this chapter.

(f) *Waiver of Deadline.* The Administrator may, in his or her discretion, accept claim of error submissions made following the deadlines imposed in this section upon a demonstration by the authorized account representative of good cause for the delay. The finding of whether good cause exists shall be in the sole discretion of the Administrator. Appeals of a decision by the Administrator under this paragraph will be addressed pursuant to the administrative appeals process in part 78 of this chapter.

§ 73.38 Closing of accounts.

(a) *General Account.* The authorized account representative of a general account may instruct the Administrator to close the general account by submitting an allowance transfer, pursuant to § 73.50 and § 73.52, requesting the transfer of all allowances held in the account to one or more other accounts in the Allowance Tracking System, and by submitting in writing, with the signature of the authorized account representative, a request to delete the general account from the Allowance Tracking System.

(b) *Inactive accounts.* If a general account shows no activity for a period of a year or more and does not contain any allowances in its subaccounts, the Administrator will notify the account's authorized account representative that the account will be closed and eliminated from the Allowance Tracking System following 20 business days from the date the notice is sent. The account will be closed following the 20-day period, unless the Administrator receives and records a request for the transfer of allowances into the account pursuant to § 73.52 before the end of the 20-day period, or the authorized account representative submits, in writing, demonstration of good cause as to why the inactive account should not be closed. The finding of whether good cause exists shall be in the sole discretion of the Administrator.

Subpart D—Allowance Transfers

§ 73.50 Scope and submission of transfers.

(a) *Scope of transfers.* Except as provided in § 73.51 and § 73.52, the Administrator will record transfers of an allowance to and from Allowance Tracking System accounts, including, but not limited to, transfers of an allowance to and from contemporaneous future year subaccounts, and transfers of an allowance to and from compliance subaccounts and current year subaccounts, and transfers of all allowances allocated for a unit for each calendar year, in perpetuity.

(b) *Submission of transfers.* (1) Authorized account representatives seeking recordation of an allowance transfer shall request such transfer by submitting to the Administrator, in a format to be specified by the Administrator, an Allowance Transfer Form. To be considered correctly submitted the request for transfer shall include:

(i) The numbers identifying both the transferror and transferee accounts;

(ii) A specification by serial number of each allowance to be transferred, or correct indication on the allowance transfer where a request involves the transfer of the unit's allowances in perpetuity;

(ii) Signatures of the authorized account representatives of both the transferror and transferee accounts;

(iv) The dates of the signatures of the authorized account representatives;

(v) The numbers identifying the authorized account representatives for both the transferror and transferee account; and

(vi) Where the transferee account has not been established, information as required pursuant to § 73.31 (b) or (c).

(2) Transfers of allowances to or from compliance subaccounts submitted for recordation following the allowance transfer deadline will not be recorded until after completion of the process of recordation set forth in § 73.34(a).

§ 73.51 Prohibition.

Except as provided in § 73.34(a), the Administrator will not record a transfer of allowances from a future year subaccount to a subaccount for an earlier year.

§ 73.52 EPA recordation.

(a) *General recordation.* Except as provided in § 73.50, § 73.51, and this paragraph (a), the Administrator will record an allowance transfer by no later than five business days following receipt of an allowance transfer request pursuant to § 73.50, by moving each allowance from the transferror account to the transferee account as specified by the request pursuant to § 73.50, provided that:

(1) The information submitted pursuant to § 73.50 is complete;

(2) The transferror account includes each allowance identified by serial number in the allowance transfer request submitted pursuant to § 73.50, except when a request for transfer of the unit's allowances in perpetuity is indicated correctly on the allowance transfer submission;

(3) If the allowances identified by serial number specified pursuant to § 73.50(b)(1)(ii) are subject to the limitation on transfer imposed pursuant to § 72.44(h)(i), of this chapter, the transfer is in accordance with such limitation; and

(4) The transfer meets all applicable requirements of this subpart.

(b) Where an allowance transfer submitted for recordation fails to meet the requirements of this subpart, the Administrator will not record such transfer.

§ 73.53 Notification.

(a) *Notification of recordation.* The Administrator will notify each party to an allowance transfer within five business days following the recordation of the transfer. Notice will be given in writing or in a format to be specified by the Administrator, to the authorized account representatives of both the transferror and transferee accounts.

(b) *Notification of non-recordation.* By no later than five business days following receipt of an allowance transfer request by the Administrator, the Administrator will notify, in writing or in a format to be specified by the Administrator, the authorized account representatives of the accounts subject to the allowance transfer request submitted for recordation of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of an allowance transfer request for recordation following notification of non-recordation.

Subpart E—[Amended]

4. Section 73.72 Direct sales.

* * * * *

(c) *Price.* Allowances in the direct sale will be sold at $1,500 per allowance, adjusted by the Consumer Price Index (CPI). The following formula will be used each year to calculate the price:

$$\$1{,}500 \times \left(1 + \frac{\text{CPI (year)} - \text{CPI (1990)}}{\text{CPI (1990)}} \right)$$

* * * * *

5. Part 73 is amended by adding subpart F to read as follows:

Subpart F—Energy Conservation and Renewable Energy Reserve

73.80 Operation of allowance reserve program for conservation and renewable energy.
73.81 Qualified conservation measures and renewable energy generation.
73.82 Application for allowances from reserve program.
73.83 Secretary of Energy's action on net income neutrality applications.
73.84 Administrator's action on applications.
73.85 Administrator review of the reserve program.
73.86 State regulatory autonomy.

Appendix A to Subpart F—List of Qualified Energy Conservation Measures

Subpart F—Energy Conservation and Renewable Energy Reserve

§ 73.80 Operation of allowance reserve program for conservation and renewable energy.

(a) *General.* The Administrator will allocate allowances from the Conservation and Renewable Energy Reserve (the "Reserve") established under subpart B based on verified kilowatt hours saved through the use of one or more qualified energy conservation measures or based on kilowatt hours generated by qualified renewable energy generation. Allowances will be allocated to applicants that meet the requirements of this subpart according to the formulas specified in § 73.82(d), and in the order in which applications are received, except where provided for in § 73.84 and § 73.85, until a total of 300,000 allowances have been allocated.

(b) *Period of applicability.* Allowances will be allocated under this subpart for qualified energy conservation measures or renewable energy generation sources that are operational on or after January 1, 1993, and before the date on which any unit owned or operated by the applicant becomes a Phase I unit or a Phase II unit.

(c) *Termination of the Reserve.* The Administrator will reallocate any allowances remaining in the Reserve after January 2, 2010 to the affected units from whom allowances were withheld by the Administrator, in accordance with section 404(g), for purposes of establishing the Reserve. Each unit's allocation under this paragraph will be calculated as follows:

$$\frac{\text{Remaining allowances in the Reserve} \times \text{Unit's allowances withheld}}{\text{Total amount in Reserve}}$$

(Allowances will be rounded to the nearest allowance)

§ 73.81 Qualified conservation measures and renewable energy generation.

(a) *Qualified energy conservation measures.* A qualified energy conservation measure is a demand-side measure not operational until the period of applicability, implemented in the residence or facility of a customer to whom the utility sells electricity, that:

(1) Is specified in appendix A(1) of this subpart; or

(2) In the case of a device or material that is not included in appendix A(1) of this subpart,

(i) Is a cost-effective demand-side measure consistent with an applicable least-cost plan or least-cost planning process that increases the efficiency of the customer's use of electricity (as measured in accordance with § 73.82(c)) without increasing the use by the customer of any fuel other than qualified renewable energy, industrial waste heat, or, pursuant to paragraph (b)(5) of this section, industrial waste gases;

(ii) Is implemented pursuant to a conservation program approved by the utility regulatory authority, which certifies that it meets the requirements of paragraph (a)(2)(i) of this section and is not excluded by paragraph (b) of this section; and

(iii) Is reported by the applicant in its application to the Reserve.

(b) *Non-qualified energy conservation measures.* The following energy conservation measures shall not qualify for Allowance Reserve allocations:

(1) Demand-side measures that were operational before January 1, 1992;

(2) Supply-side measures;

(3) Conservation programs that are exclusively informational or educational in nature;

(4) Loan management measures that lead to economic reduction of electric energy demand during a utility's peak generating periods, unless kilowatt hour savings can be verified by the utility pursuant to § 73.82(c); or

(5) Utilization of industrial waste gases, unless the applicant has certified that there is no net increase in sulfur dioxide emissions from such utilization.

(c) *Qualified renewable energy generation.* Qualified renewable energy generation is electrical energy generation, not operational until the period of applicability, that:

(1) Is specified in appendix A(3) of this subpart; or

(2) In the case of renewable energy generation that is not included in appendix A(3) of this subpart is:

(i) Consistent with a least cost plan or a least cost planning process and derived from biomass (*i.e.*, combustible energy-producing materials from biological sources which include wood,

plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste), solar, geothermal, or wind resources;

(ii) Implemented pursuant to approval by the utility regulatory authority, which certifies that it meets the requirements of paragraphs (c)(2)(i) and (c)(2)(ii) of this section and is not excluded by paragraph (d) of this section; and

(iii) Is reported by the applicant in its application to the Reserve.

(d) *Non-qualified renewable energy generation.* The following renewable energy generation shall not qualify for Allowance Reserve allocations:

(1) Renewable energy generation that was operational before January 1, 1992;

(2) Measures that reduce electricity demand for a utility's customers without providing electric generation directly for sale to customers; and

(3) Measures that appear on the list of qualified energy conservation measures in Appendix A(1) of this subpart.

§ 73.82 Application for allowances form reserve program.

(a) *Application Requirements.* Each application for Conservation and Renewable Energy Reserve allowances, shall:

(1) Certify that the applicant is a utility;

(2) Demonstrate that the applicant, any subsidiary of the applicant, or any subsidiary of the applicant's holding company, is an owner or operator, in whole or in part, of at least one Phase I or Phase II unit by including in the application the name and Allowance Tracking System account number of a Phase I or Phase II unit which it owns or operates and for which it is listed as an owner or operator on the certificate of representation submitted by the designated representative for the unit pursuant to § 72.20 of this chapter;

(3) Through certification, demonstrate that the applicant is paying in whole or in part for one or more qualified energy conservation measures or qualified renewable energy generation (that became operational during the period of applicability) either directly or through payment to another person that purchases the qualified energy conservation measure or qualified renewable energy generation;

(4) Demonstrate that the applicant is subject to a least cost plan or a least cost planning process that:

(i) provides an opportunity for public notice and comment or other public participation processes;

(ii) evaluates the full range of existing and incremental resources in order to meet expected future demand at lowest system cost;

(iii) treats demand-side resources and supply-side resources on a consistent and integrated basis;

(iv) takes into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk;

(v) may take into account other factors, including the social and environmental costs and benefits of resource investments; and

(vi) is being implemented by the applicant to the maximum extent practicable.

(5) Demonstrate that the qualified energy conservation measure adopted or qualified renewable energy generated, or both, are consistent with the least cost plan or least cost planning process;

(6) If the applicant is subject to the rate-making jurisdiction of a State or local utility regulatory authority, its least cost plan or least cost planning process has been approved or accepted by the utility regulatory authority in the State or locality in which the qualified conservation measure(s) are adopted or in which the qualified renewable energy generation is utilized, and such State or local utility regulatory authority certifies that the least-cost plan or least-cost planning process meets the requirements of paragraph (a)(4) of this section;

(7) If the applicant is not subject to the rate-making jurisdiction of a State or local regulatory authority, its least cost plan or least cost planning process has been approved or has been accepted by the utility regulatory authority with rate-making jurisdiction over the applicant, and such utility regulatory authority certifies that the least cost plan or least cost planning process meets the requirements of paragraph (a)(4) of this section;

(8) If the applicant is an independent power production facility that sells qualified renewable energy generation to another utility, the applicant has enclosed documentation that such qualified renewable energy generation was purchased pursuant to the purchasing utility's least cost plan or least cost planning process, which has been approved or accepted by the purchasing utility's utility regulatory authority.

(9)(i) If the applicant is an investor-owner utility subject to the ratemaking jurisdiction of a State utility regulatory authority and is submitting an application on the basis of one or more qualified energy conservation measures, such State utility regulatory authority has established a procedure for determining rates and charges ensuring net income neutrality, as defined in § 72.2 of this chapter, including a provision that the utility's net income is compensated in full (considering factors such as risk) for lost sales attributable to the utility's conservation programs, which may include:

(A) General ratemaking for formulas that decouple utility profits from actual utility sales;

(B) Specific rate adjustment formulas that allow a utility to recover in its retail rates the full costs of conservation measures plus any associated net revenues lost as a result of reduced sales resulting from conservation initiatives; or

(C) Conservation incentive mechanisms designed to provide positive financial rewards to a utility to encourage implementation of cost-effective measures;

(ii) Provided that the existence of any one of the categories of ratemaking or rate adjustment formulas or conservation incentive mechanisms specified in paragraph (a)(9)(i) of this section shall not necessarily constitute fulfillment of the net income neutrality requirement unless, pursuant to § 73.83, the Secretary of Energy has certified the establishment of such net income neutrality;

(10) Demonstrate that the applicant has implemented the qualified energy conservation measures or used the qualified renewable energy generation specified in the application during the period of applicability;

(11) Demonstrate the extent to which installation of the qualified conservation measure(s) has achieved actual energy savings, by stating, on the basis of the performance of the measure(s) following installation:

(i) The amount of kilowatt hour savings resulting from the measure(s) in the given year(s);

(ii) Pursuant to paragraph (c) of this section, the methodology used to calculate the kilowatt hour savings; and

(iii) The name, address, and phone number of the person who performed the calculation of kilowatt hour savings;

(12) Report the type and amount of yearly qualified renewable energy generation, by stating (and submitting documentation, including copies of plant operation records, supporting such statements) the kilowatt hours of qualified renewable energy generated during a previous calendar year or years; and

(13) Report the extent to which qualified renewable energy generation was produced in combination with other energy sources (hereafter "hybrid generation") by stating (and submitting documentation, including copies of plant operation records, supporting such statements) the heat input and heat

rate of the non-qualified renewable generation, the total annual kilowatt hours generated, and the kilowatt hours that can be attributed to qualified renewable energy generation;

(14) Demonstrate the extent to which the implementation of qualified energy conservation measures or the use of qualified renewable energy generation has resulted in avoided tons of sulfur dioxide emissions by the utility during the period of applicability, pursuant to paragraph (d) of this section.

(b) *Application to the Secretary of Energy.* For purposes of paragraph (a)(9) of this section, the applicant shall fulfill the following requirements:

(1) If a utility applying for allowances from the Reserve has not received certification of net income neutrality from the Secretary of Energy or such certification is no longer applicable, the applicant shall submit to the Secretary of Energy:

(i) A copy of the relevant State utility regulatory authority's final order or decision setting forth the approved ratemaking mechanisms that ensure that a utility's net income will be at least as high upon implementation of energy conservation measures as such net income would have been if the energy conservation measures has not been implemented;

(ii) A description of how the State utility regulatory authority's order or decision meets the definition of net income neutrality as defined in § 72.2; and

(iii) Any additional information necessary for Secretary of Energy to certify that the State regulatory authority has established rates and charges that ensure net income neutrality.

(2) If a utility applying for allowances from the Reserve has already received certification of net income neutrality from the Secretary of Energy in connection with a previous application for allowances, and the ratemaking methods or procedures that ensure net income neutrality have not been altered, the applicant shall certify that the ratemaking methods and procedures that led to the original certification are still in place.

(c) *Verification of energy savings methodology.* For the purposes of paragraph (a)(11) of this section:

(1) Applicants subject to the ratemaking jurisdiction of a State utility regulatory authority shall use the energy conservation verification methodology approved by such authority in support of energy conservation applications under this subpart and part 72 of this chapter, provided that

(i) The authority in question uses this methodology to determine the applicant's entitlement to performance-based rate adjustments, which permit a utility's rates to be adjusted for additional kilowatt hours saved due to the utility's energy conservation programs;

(ii) Such performance based rate adjustments are subject to modification either prospectively or retrospectively to reflect periodic evaluations of energy savings secured by the applicant; and

(iii) The applicant has provided the Administrator with a description of the State utility regulatory authority's verification methodology and documentation that the requirements of this paragraph (e) have been met.

(2) All other applicants, including applicants whose rates are not subject to the ratemaking jurisdiction of a State utility regulatory authority shall demonstrate to the satisfaction of the Administrator through submission of documentation that savings have been achieved and may use the EPA Conservation Verification Protocol.

(3) All records of verification of energy savings shall be kept on file by the applicant for a period of 3 years. The Administrator may extend this period for cause at any time prior to the end of 3 years by notifying the applicant in writing.

(4) The Administrator reserves the right to conduct independent reviews, analyses, or audits to ascertain that the verification is valid and correct. If the Administrator determines that the verification is not valid or correct, the Administrator may revise the allocation of allowances to an applicant or require the surrender of allowances from the applicant's Allowance Tracking System account.

(d) *Calculation of allowances to be allocated.*

(1) In the case of an application submitted on the basis of qualified energy conservation measures, the sulfur dioxide emissions tonnage deemed avoided for any calendar year shall be equal to the product of:

$$\frac{(A)\times(B)}{2000\ \text{lbs./ton}}$$

(Rounded to the nearest ton)

Where:

(A)=the kilowatt hours that were not, but would otherwise have been, supplied by the utility during such year in the absence of such qualified energy conservation measures.

(B)=0.004 lbs. of sulfur dioxide per kilowatt hour.

(2) In the case of an application submitted on the basis of qualified renewable energy generation, the sulfur dioxide emissions tonnage deemed avoided for any calendar year shall be equal to the product of:

$$\frac{(A)\times(B)}{2000\ \text{lbs./ton}}$$

(Rounded to the nearest ton)

Where:

(A)=the actual kilowatt hours of qualified renewable energy generated or purchased by the applicant (based on the qualified renewable energy generation portion for hybrid generation).

(B)=0.004 lbs. of sulfur dioxide per kilowatt hour.

(e) *Certification by Applicant's Certifying Official.*

(1) Certification of all application requirements, including the net income neutrality requirements, shall be made by a certifying official of the applicant upon such official's verification of all information and documentation submitted.

(2) The applicant shall submit a certification statement signed by the applicant's certifying official that reads "I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false material information, or omitting material information, including the possibility of fine or imprisonment for violations."

(f) *Certification by State Utility Regulatory Authority.* Applicants subject to the ratemaking jurisdiction of a State utility regulatory authority shall include in their applications a certification by the State utility regulatory authority's certifying official that it has reviewed the application, including supporting documentation, and finds it to be accurate, complete, and consistent with all applicable requirements of this subpart.

(g) *Time period to apply.* (1) Beginning no earlier than July 1, 1993, and no earlier than July 1 of each subsequent year, applicants may apply to the Administrator for allowances from the Reserve for emissions avoided in a previous year or years by use of qualified energy conservation measures or qualified renewable energy generation that became operational during the period of applicability; and

(2) Beginning no earlier than January 1, 1993, any applicant may apply to the Secretary of Energy for the Secretary's certification of net income neutrality where the application is based on the use of one or more qualified energy conservation measures.

(3) Applications will be received by the Administrator and the Secretary of Energy until January 2, 2010, pursuant to § 73.80(c), or until no allowances remain in the Reserve.

(h) *Submittal location.* Applicants shall submit one copy of the completed Reserve application, not including the net income neutrality application, via registered mail to the Administrator at an address to be specified in later guidance. Applicants shall submit 10 copies of the net income neutrality application via registered mail to the Department of Energy at the following address: Department of Energy, Office of Conservation and Renewable Energy, Mail Stop CE–10, Room 6c–036, 1000 Independence Avenue, SW., Washington, DC 20585, Attn: Net Income Neutrality Certification.

§ 73.83 Secretary of Energy's action on net income neutrality applications.

(a) *First come, first served.* The Secretary of Energy will process and certify net income neutrality applications on a "first-come, first served" basis, according to the order, by date and time, in which they are received from either the applicant or, in the case of an application submitted to the Administrator and then forwarded to the Secretary, from the Administrator.

(b) *Deficient applications.* If the Secretary of Energy determines that the net income neutrality certification application does not meet the requirements of § 73.82 (a)(9) and (b), the Secretary will notify the applicant and the Administrator in writing of the deficiency. The applicant may then supply additional information or a new revised application as necessary for the Secretary to make a determination that the applicant meets the requirements of § 73.28(a)(9) and (b). Additional information or revised applications will be processed according to the date of receipt of such information or revisions.

(c) *Notification of approval.* The Secretary of Energy will review the net income neutrality application to determine whether it meets the requirements of § 73.82 (a)(9) and (b) and will certify this finding in writing to the applicant and to the Administrator within 60 calendar days of receipt of the net income neutrality application or a revised application, except that the Secretary may specify a later date for certification.

§ 73.84 Administrator's action on applications.

(a) *First come, first served.* The Administrator will process and approve Allowance Reserve applications, in whole or in part, on a "first-come, first-served" basis as established by the order of date of receipt, provided that the Administrator shall not allocate more than a total of 30,000 allowances in connection with applications based on any one of the four categories of qualified renewable energy generation enumerated in § 73.81(c)(2)(i) and Appendix A(3.1–3.4).

(b) *Deficient applications.* An application is deficient and will be returned by the Administrator if it fails to meet the requirements set forth in this subpart, including those set forth in § 73.82. A revised application that is submitted after being returned for failure to meet the requirements of this subpart will be processed according to the date of receipt of the revised application.

(c) *Notification of approval.* Applications that the Administrator determines to be complete and correct will be conditionally approved, subject to notification to EPA of a net income neutrality certification from the Department of Energy, within 120 calendar days of receipt. Allowances from the Reserve will be awarded subject to the Department of Energy certification, or, if a DOE certification has already been issued to the applicant, allocated to applicants from such applications depending on the availability of allowances in the Reserve. In the event the initial application approval is conditioned upon the Secretary of Energy's certification, final approval will be granted upon notification of certification by the Secretary of Energy pursuant to § 73.83. The Administrator will notify applicants of final approval in writing.

(d) *Allocation of allowances.* Beginning in 1995, the Administrator will allocate allowances from the Reserve for each approved application into the applicant's account or accounts in the Allowance Tracking System. If the applicant does not have an account in the Allowance Tracking System, or wishes to open a new account for the allowances from the Reserve, an application pursuant to § 73.31(c) must accompany the application for Reserve allowances.

(e) *Partial fulfillment of requests.* (1) In the event that the allowances available in the Reserve are less than the number that could otherwise be allocated to an approved applicant's account under the application as approved, the applicant will receive the allowances remaining in the Reserve.

(2) In the event that a subaccount is established by EPA, pursuant to § 73.85, and the applicant is making a request for allowances not included in the subaccount, the Allowance Reserve allocations for the approved applicant will be made, in addition to any that may be allocated pursuant to paragraph (f)(3) of this section, from any allowances remaining in the Reserve that are not contained in the subaccount.

(f) *Oversubscription of the Reserve.*

(1) In the event that the Reserve becomes oversubscribed by more than one applicant on a single day, the allowances remaining in the Reserve will be distributed on a pro rata basis to applicants meeting the requirements of § 73.82.

(2) If Reserve applications are received by the Administrator after all allowances from the Reserve have been allocated, the Administrator will so notify the applicant within 5 business days after receipt of the application.

(3) In the event that applications meeting the requirements pursuant to § 73.82 are received by the Administrator prior to February 1, 1998, and

(i) All remaining allowances in the Reserve have been placed in a subaccount pursuant to § 73.85; and

(ii) The applicant is not eligible for an allocation of allowances from the subaccount; the application will be placed on a waiting list in order of receipt.

(iii) The Administrator will notify the applicant of such action within 5 business days after receipt of the application.

(4) If any allowances are returned to the Reserve after February 1, 1998 pursuant to § 73.85(c), the Administrator will review the wait-listed applications in order of receipt and allocate any remaining allowances to the approved applicants in the order of their receipt until no more allowances remain in the Reserve.

(g) *Applications for allowances based on the same avoided emissions from the same energy conservation measures or renewable energy generation.*

(1) The Administrator will not award allowances to more than one applicant for the same avoided emissions from the same energy conservation measure or the same qualified renewable energy generation, and will process and act on such duplicative applications on a "first-come, first-serve" basis as determined by the order of date of receipt.

(2) Any allowances awarded pursuant to two or more applications received on the same date based on the same avoided emissions from the same energy conservation measure or the same renewable electric generation will be divided equally between all such applicants unless the Administrator is otherwise directed by all such applicants.

§ 73.85 Administrator review of the reserve program.

(a) *Administrator review of the Reserve and creation of a subaccount.* In the event that an allocation of allowances from the Reserve pursuant to a pending application would bring the total number of allowances allocated to a number greater than 240,000, the Administrator will review the distribution of all allowances allocated as follows:

(1) If at least 60,000 allowances have been allocated from the Reserve for *each* of

(i) Qualified energy conservation measures, and

(ii) Qualified renewable energy generation, allocations of allowances will continue pursuant to § 73.82, until no more allowances remain in the Reserve.

(2) If fewer than 60,000 allowances have been allocated for either qualified energy conservation measures or qualified renewable energy generation, the Administrator will establish a subaccount for the allocation of allowances for applications based on the category for which fewer than 60,000 allowances have been allocated. The subaccount will contain allowances equal to 60,000 less the number of allowances previously allocated for such category.

(b) *Allocation of allowances from the subaccount.* The Administrator will allocate allowances from the subaccount established pursuant to paragraph (a) of this section to approved and DOE certified applicants that fulfill the requirements of this subpart, including § 73.82 and § 73.83, on a "first-come, first-served basis", pursuant to § 73.84(a), until the subaccount is depleted or closed pursuant to paragraph (c) of this section.

(c) *Closure of the subaccount.* Unless all allowances in the subaccount have been previously allocated, the Administrator will terminate the subaccount not later than February 1, 1998 and return any allowances remaining in the subaccount to the general account of the Reserve. After all Reserve allocations have been made to applicants with approved and DOE certified applications subject to § 73.84(f)(3), the Administrator will allocate any remaining allowances to any applicants that meet the requirements of this subpart, including § 73.82 and § 73.83, on a "first-come, first-served" basis, pursuant to § 73.84.

§ 73.86 State regulatory autonomy.

Nothing in this Subpart shall preclude a state or state regulatory authority from providing additional incentives to utilities to encourage investment in any conservation measures or renewable energy generation.

Appendix A to Subpart F—List of Qualified Energy Conservation Measures, Qualified Renewable Generation, and Measures Applicable for Reduced Utilization

1. Demand-side Measures Applicable for the Conservation and Renewable Energy Reserve Program or Reduced Utilization

The following listed measures are approved as "qualified energy conservation measures" for purposes of the Conservation and Renewable Energy Reserve Program or reduced utilization qualified energy conservation plans under § 72.43 of this chapter. Measures not appearing on the list may also be qualified conservation measures if they meet the requirements specified in § 73.81(a) of this part.

1.1 Residential

1.1.1 Space Conditioning

- Electric furnace improvements (intermittent ignition, automatic vent dampers, and heating element change-outs)
- Air conditioner (central and room) upgrades/replacements
- Heat pump (ground source, solar assisted, and conventional) upgrades/replacements
- Cycling of air conditioners and heat pumps
- Natural ventilation
- Heat recovery ventilation
- Clock thermostats
- Setback thermostats
- Geothermal steam direct use
- Improved equipment controls
- Solar assisted space conditioning (ventilation, air-conditioning, and desiccant cooling)
- Passive solar designs
- Air conditioner and heat pump clean and tune-up
- Heat pipes
- Whole house fans
- High efficiency fans and motors
- Hydronic pump insulation
- Register relocation
- Register size and blade configuration
- Return air location
- Duct sizing
- Duct insulation
- Duct sealing
- Duct cleaning
- Shade tree planting

1.1.2 Water Heating

- Electric water heater upgrades/replacements
- Electric water heater tank wraps/blankets
- Low-flow showerheads and fittings
- Solar heating and pre-heat units
- Geothermal heating and pre-heat units
- Heat traps
- Water heater heat pumps
- Recirculation pumps
- Setback thermostats
- Water heater cycling control
- Solar heating for swimming pools
- Pipe wrap insulation

1.1.3 Lighting

- Lamp replacement
- Dimmers
- Motion detectors and occupancy sensors
- Photovoltaic lighting
- Fixture replacement
- Outdoor lighting controls

1.1.4 Building Envelope

- Attic, basement, ceiling, and wall insulation
- Passive solar building systems
- Exterior roof insulation
- Exterior wall insulation
- Exterior wall insulation bordering unheated space (e.g., a garage)
- Knee wall insulation in attic
- Floor insulation
- Perimeter insulation
- Storm windows/doors
- Caulking/weatherstripping
- Multi-glazed inserts for sliding glass doors
- Sliding door replacements
- Installation of French doors
- Hollow core door replacement
- Radiant barriers
- Window vent conversions
- Window replacement
- Window shade screens
- Low-e windows
- Window reduction
- Attic ventilation
- Whole house fan
- Passive solar design

1.1.5 Other Appliances

- Refrigerator replacements
- Freezer replacements
- Oven/range replacements
- Dishwasher replacements
- Clothes washer replacements
- Clothes dryer replacements
- Customer located power generation based on photovoltaic, solar thermal, biomass, wind or geothermal resources
- Swimming pool pump replacements
- Gasket replacements
- Maintenance/coil cleaning

1.2 Commercial

1.2.1 Heating/Ventilation/Air Conditioning (HVAC)

- Heat pump replacement
- Fan motor efficiency
- Resizing of chillers
- Heat pipe retrofits in air conditioning units
- Dehumidifiers
- Steam trap insulation
- Radiator thermostatic valves
- Variable speed drive on fan motor
- Solar assisted HVAC including ventilation, chillers, heat pumps, and desiccants
- HVAC piping insulation
- HVAC ductwork insulation
- Boiler insulation
- Automatic night setback
- Automatic economizer cooling
- Outside air control

- Hot and cold deck automatic reset
- Reheat system primary air optimization
- Process heat recovery
- Deadband thermostat
- Timeclocks on circulating pumps
- Chiller system
- Increase condensing unit efficiency
- Separate make-up air for exhaust hoods
- Variable air volume system
- Direct tower cooling (chiller strainer cycle)
- Multiple chiller control
- Radiant heating
- Evaporative roof surface cooling
- Cooling tower flow control
- Ceiling fans
- Evaporative cooling
- Direct expansion cooling system
- Heat recovery ventilation (water and air-source)
- Set-back controls for heating/cooling
- Make-up air control
- Manual fan switches
- Energy saving exhaust hood
- Night flushing
- Spot radiant heating
- Terminal regulated air volume control scheme
- Variable speed motors for HVAC system
- Waterside economizers
- Airside economizer
- Gray water systems
- Well water for cooling

1.2.2 Building envelope
- Insulation
- Wall insulation
- Floor/slab insulation
- Roof insulation
- Window and door upgrades, replacements, and films (to reduce solar heat gains)
- Passive solar design
- Earth berming
- Shading devices and tree planting
- High reflectivity roof coating
- Evaporative cooling
- Infiltration reduction
- Weatherstripping
- Caulking
- Low-e windows
- Multi-glazed windows
- Replace glazing with insulated walls
- Thermal break window frames
- Tinted glazing
- Vapor barrier
- Vestibule entry

1.2.3 Lighting
- Electronic ballast replacements
- Delamping
- Reflectors
- Occupancy sensors
- Daylighting with controls
- Photovoltaic lighting
- Efficient exterior lighting
- Manual selective switching
- Efficient exit signs
- Daylighting construction
- Cathode cutout ballasts
- High intensity discharge luminaries
- Outdoor light timeclock and photocell

1.2.4 Refrigeration
- Refrigerator replacement
- Freezer replacement
- Optimize heat gains to refrigerated space
- Optimize defrost control
- Refrigeration pressure optimization control
- High efficiency compressors
- Anti-condensate heater control
- Floating head pressure
- Hot gas defrost
- Parallel unequal compressors
- Variable speed compressors
- Water cooler controls
- Waste heat utilization
- Air doors on refrigeration equipment

1.2.5 Water Heating
- Electric water heating upgrades/replacements
- Electric water heater wraps/blankets
- Pipe insulation
- Solar heating and/or pre-heat units
- Geothermal heating and/or pre-heat units
- Circulating pump control
- Point-of-use water heater
- Heat recovery domestic water heater (DWH) system
- Chemical dishwashing system
- End-use reduction using low-flow fittings

1.2.6 Other end-uses and miscellaneous
- Energy management control systems for building operations
- Customer located power based on photovoltaic, solar thermal, biomass, wind, and geothermal resources
- Energy efficient office equipment
- Customer-owned transformer upgrades and proper sizing

1.3 Industial

1.3.1 Motors
- Retire inefficient motors and replace with energy efficient motors, including the use of electronic adjustable speed or variable frequency drives
- Rebuild motors to operate more efficiently through greater contamination protection and improved magnetic materials
- Install self-starters
- Replace improperly sized motors

1.3.2 Lighting
- Electronic ballast replacement/improvement
- Electromagnetic ballast upgrade
- Installation of reflectors
- Substitution of lamps with built-in automatic cathode cut-out switches
- Modify ballast circuits with additional impedance devices
- Metal halide and high pressure sodium lamp retrofits
- High pressure sodium retrofits
- Daylighting with controls
- Occupancy sensors
- Delamping
- Photovoltaic lighting
- Two step and dimmable high intensity discharge ballast

1.3.3 Heating/Ventilation/Air Conditioning (HVAC)
- Heat pump replacement/upgrade
- Furnace upgrade/replacement
- Fan motor efficiency
- Resizing of chillers
- Heat pipe retrofits on air conditioners
- Variable speed drive on fan motor
- Solar assisted HVAC including ventilation, chillers, heat pumps and desiccants

1.3.4 Industrial Processes
- Upgrades in heat transfer equipment
- Insulation and burner upgrades for industrial furnaces/ovens/boilers to reduce electricity loads on motors and fans
- Insulation and redesign of piping
- Upgrades/retrofits in condenser/evaporation equipment
- Process air and water filtration for improved efficiency
- Upgrades of catalytic combustors
- Solar process heat
- Customer located power based on photovoltaic, solar thermal, biomass, wind, and geothermal resources
- Power factor controllers
- Utilization of waste gas fuels
- Steam line and steam trap repairs/upgrades
- Compressed air system improvements/repairs
- Industrial process heat pump
- Optimization of equipment lubrication or maintenance
- Resizing of process equipment for optimal energy efficiency
- Use of unique thermodynamic power cycles

1.3.5 Building Envelope
- Insulation of ceiling, walls, and ducts
- Window and door replacement/upgrade, including thermal energy barriers
- Caulking/weatherstripping

1.3.6 Water Heating
- Electric water heater upgrades/replacements
- Electric water heater wraps/blankets
- Pipe insulation
- Low-flow showerheads and fittings
- Solar heating and pre-heat units
- Geothermal heating and pre-heat units

1.3.7 Other End-uses and miscellaneous
- Refrigeration system retrofit/replacement
- Energy management control systems and end use metering
- Customer-owned transformer retrofits/replacements and proper sizing

1.4 Agricultural

1.4.1 Space Conditioning
- Building envelope measures
- Efficient HVAC equipment
- Heat pipe retrofit on air conditioners
- System and control measures
- Solar assisted HVAC including ventilation, chillers, heat pumps, and desiccants
- Air-source and geothermal heat pumps replacement/upgrades

1.4.2 Water heating
- Upgrades/replacements
- Water heater wraps/blankets
- Pipe insulation
- Low-flow showerheads and fittings
- Solart heating and/or pre-hear units
- Geothermal heating and/or pre-heat units

1.4.3 Lighting
- Electronic ballast replacements
- Delamping
- Reflectors
- Occupancy sensors
- Daylighting with controls
- Photovoltaic lighting
- Outdoor lighting controls

1.4.4 Pumping/Irrigation
- Pump upgrades/retrofits
- Computerized pump control systems
- Irrigation load management strategies
- Irrigation pumping plants
- Computer irrigation control
- Surge irrigation
- Computerized scheduling of irrigation

• Drip irrigation systems
1.4.5 Motors
• Retire inefficient motors and replace with energy efficient motors, including the use of electronic adjustable speed and variable frequency drives
• Rebuild motors to operate more efficiently through greater contamination protection and improved magnetic materials
• Install self-starters
• Replace improperly sized motors
11.4.6 Other end uses
• Ventilation fans
• Cooling and refrigeration system upgrades
• Grain drying using unheated air
• Grain drying using low temperature electric
• Customer-owned transformer retrofits/replacements and proper sizing
• Programmable controllers for electrical farm equipment
• Controlled livestock ventilation
• Water heating for production agriculture
• Milk cooler heat exchangers
• Direct expansion/ice bank milk cooling
• Low energy precision application systems
• Heat pump crop drying
1.5 Government Services Sector
1.5.1 Streetlighting
• Replace incandescent and mercury vapor lamps with high pressure sodium and metal halide
1.5.2 Other
• Energy efficiency improvements in motors, pumps, and controls for water supply and waste water treatment
• District heating and cooling measures derived for cogeneration that result in electricity savings

2. Supply-side Measures Applicable for Reduced Utilization

Supply-side measures that may be approved for purposes of reduced utilization plans under § 72.43 include the following:
2.1 Generation efficiency
• Heat rate improvement programs
• Availability improvement programs
• Coal cleaning measures that improve boiler efficiency
• Turbine improvements
• Boiler improvements
• Control improvements, including artificial intelligence and expert systems
• Distributed control—local (real-time) versus central (delayed)
• Equipment monitoring
• Performance monitoring
• Preventive maintenance
• Additional or improved heat recovery
• Sliding/variable pressure operations
• Adjustable speed drives
• Improved personnel training to improve man/machine interface
2.2 Transmission and distribution efficiency
• High efficiency transformer switchouts using amorphous core and silicon steel technologies
• Low-loss windings
• Innovative cable insulation
• Reactive power dispatch optimization
• Power factor control
• Primary feeder reconfiguration
• Primary distribution voltage upgrades
• High efficiency substation transformers
• Controllable series capacitors
• Real-time distribution data acquisition analysis and control systems
• Conservation voltage regulation

3. Renewable Energy Generation Measures Applicable for the Conservation and Renewable Energy Reserve Program

The following listed measures are approved as "qualified renewable energy generation" for purposes of the Conservation and Renewable Energy Reserve Program. Measures not appearing on the list may also be qualified renewable energy generation measures if they meet the requirements specified in § 73.81.
3.1 Biomass resources
• Combustible energy-producing materials from biological sources which include: wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste.
3.2 Solar resources
• Solar thermal systems and the non-fossil fuel portion of solar thermal hybrid systems
• Grid and non-grid connected photovoltaic systems, including systems added for voltage or capacity augmentation of a distribution grid.
3.4 Geothermal resources
• Hydrothermal or geopressurized resources used for dry steam, flash steam, or binary cycle generation of electricity.
3.5 Wind resources
• Grid-connected and non-grid-connected wind farms
• Individual wind-driven electrical generating turbines
(The information requirements in this subpart have been approved by the Office of Management and Budget under the control number 2060–0221.)

6. Title 40 is amended by adding part 75 to read as follows:

PART 75—CONTINUOUS EMISSION MONITORING

Subpart A—General

Sec.
75.1 Purpose and scope.
75.2 Applicability.
75.3 General Acid Rain Program provisions.
75.4 Compliance dates.
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75.6 Incorporation by reference.
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Subpart B—Monitoring Provisions

75.10 General operating requirements.
75.11 Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors).
75.12 Specific provisions for monitoring NO_x emissions (NO_x and diluent gas monitors).
75.13 Specific provisions for monitoring CO_2 emissions.
75.14 Specific provisions for monitoring opacity.
75.15 Specific provisions for monitoring SO_2 emissions removal by qualifying Phase I technology.
75.16 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for SO_2 emissions and heat input determinations.
75.17 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for NO_x emission rate.
75.18 Specific provisions for monitoring emissions from common and by-pass stacks for opacity.

Subpart C—Operation and Maintenance Requirements

75.20 Certification and recertification procedures.
75.21 Quality assurance and quality control requirements.
75.22 Reference test methods.
75.23 Alternatives to ASTM methods.
75.24 Out-of-control periods.

Subpart D—Missing Data Substitution Procedures

75.30 General provisions.
75.31 Initial missing data procedures.
75.32 Determination of monitor data availability for standard missing data procedures.
75.33 Standard missing data procedures.
75.34 Units with add-on emission controls.

Subpart E—Alternative Monitoring Systems

75.40 General demonstration requirements.
75.41 Precision criteria.
75.42 Reliability criteria.
75.43 Accessibility criteria.
75.44 Timeliness criteria.
75.45 Daily quality assurance criteria.
75.46 Missing data substitution criteria.
75.47 Criteria for a class of affected units.
75.48 Petition for an alternative monitoring system.

Subpart F—Recordkeeping Requirements

75.50 General recordkeeping provisions.
75.51 General recordkeeping provisions for specific situations.
75.52 Certification, quality assurance and quality control record provisions.
75.53 Monitoring plan.

Subpart G—Reporting Requirements

75.60 General provisions.
75.61 Notification of certification and recertification test dates.
75.62 Monitoring plan.
75.63 Certification or recertification applications.
75.64 Quarterly reports.
75.65 Opacity reports.
75.66 Petitions to the Administrator.
75.67 Retired units petitions.
Appendix A to Part 75—Specifications and Test Procedures
Appendix B to Part 75—Quality Assurance and Quality Control Procedures
Appendix C to Part 75—Missing Data Statistical Estimation Procedures
Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired Units and Oil-Fired Units
Appendix E to Part 75—Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units
Appendix F to Part 75—Conversion Procedures

Appendix G to Part 75—Determination of CO_2 Emissions
Appendix H to Part 75—Revised Traceability Protocol No. 1
Appendix I to Part 75—Optional F-factor/Fuel Flow Method [reserved]

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

Subpart A—General

§ 75.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to Sections 412 and 821 of the Clean Air Act, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 [November 15, 1990] [the Act].

(b) *Scope.* The regulations established under this part include general requirements for the installation, certification, operation, and maintenance of continuous emission or opacity monitoring systems and specific requirements for the monitoring of SO_2 emissions, volumetric flow, NO_x emissions, opacity, CO_2 emissions and SO_2 emissions removal by qualifying Phase I technologies. Specifications for the installation and performance of continuous emission monitoring systems, certification tests and procedures, and quality assurance tests and procedures are included in Appendices A and B to this part. Criteria for alternative monitoring systems and provisions to account for missing data from certified continuous emission monitoring systems or approved alternative monitoring systems are also included in the regulation.

Statistical estimation procedures for missing data are included in appendix C to this part. Optional protocols for estimating SO_2 mass emissions from gas-fired or oil-fired units and NO_x emissions from gas-fired peaking or oil-fired peaking units are included in appendices D and E, respectively, to this part. Requirements for recording and recordkeeping of monitoring data and for quarterly electronic reporting also are specified. Procedures for conversion of monitoring data into units of the standard are included in appendix F to this part. Procedures for the monitoring and calculation of CO_2 emissions are included in appendix C of this part.

§ 75.2 Applicability.

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

(b) The provisions of this part do not apply to:

(1) A new unit for which a written exemption has been issued under § 72.7 of this chapter (any new unit that serves one or more generators with total nameplate capacity of 25 MWe or less and burns only fuels with a sulfur content of 0.05 percent or less by weight may apply to the Administrator for an exemption); or

(2) An existing utility unit which serves a generator with nameplate capacity not greater than 25 MWe; or

(3) an existing simple combustion turbine; or

(4) An affected unit for which a written exemption has been issued under § 72.8 and an exception granted under § 75.67.

§ 75.3 General Acid Rain Program provisions.

The provisions of part 72, including the following, shall apply to this part:

(a) § 72.2 (Definitions);
(b) § 72.3 (Measurements, Abbreviations, and Acronyms);
(c) § 72.4 (Federal Authority);
(d) § 72.5 (State Authority);
(e) § 72.6 (Applicability);
(f) § 72.7 (New Unit Exemption);
(g) § 72.8 (Retired Units Exemption);
(h) § 72.9 (Standard Requirements);
(i) § 72.10 (Availability of Information); and
(j) § 72.11 (Computation of Time).

In addition, the procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the acid rain permit which governs the unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the acid rain permit. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed not later than the following dates (except as provided in paragraphs (d) and (e) of this section):

(1) For Phase I unit, November 15, 1993.

(2) For a substitution or a compensating unit that is designated under an approved substitution plan or reduced utilization plan pursuant to § 72.41 or § 72.43 of this chapter, the later of the following dates:

(i) November 15, 1993; or

(ii) not later than 90 days after the issuance date (or date of approval of permit revision) of the acid rain permit which governs the unit and contains the approved substitution or reduced utilization plan.

(3) For a Phase II unit, January 1, 1995.

(b) In accordance with § 75.20, the owner or operator of each new affected unit shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed on or before the later of the following dates:

(1) January 1, 1995; or

(2) Not later than 90 days after the date the unit commences commercial operation, not to exceed the date the unit is declared commercial in accordance with DOE Form EIA–860 instructions (i.e., the date the unit is turned over to the dispatcher).

(c) In accordance with § 75.20, the owner or operator of an existing unit that did not serve a generator with a nameplate capacity greater than 25 MWe on November 15, 1990, but serves such a generator after November 15, 1990, shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed on or before the later of the following dates:

(1) January 1, 1995; or

(2) Not later than 90 days after the date the unit begins to serve a generator with a nameplate capacity greater than 25 MWe.

(d) In accordance with § 75.20, the owner or operator of an existing unit that is shut down and is not yet operating by the applicable dates listed in paragraph (a) of this section, shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed not later than 90 days after the date that the unit recommences commercial operation of the affected unit, not to exceed the date the unit is declared commercial in accordance with DOE Form EIA–860 instructions (i.e., the date the unit is turned over to the dispatcher).

(e) In accordance with § 75.20, the owner or operator of a unit with a qualifying Phase I technology which requires the use of an inlet SO_2-diluent continuous emission monitoring system for the purpose of monitoring SO_2 emissions removal from January 1, 1997

through December 31, 1999 shall ensure that all certification tests for the inlet and outlet SO_2-diluent continuous emission monitoring systems are completed no later than January 1, 1997.

§75.5 Prohibitions.

(a) A violation of any applicable regulation in this part by the owners or operators or the designated representative of an affected source or an affected unit is a violation of the Act.

(b) No owner or operator of an affected unit shall operate the unit without complying with the requirements of §§ 75.2 through 75.67 and appendices A through G of this part.

(c) No owner or operator of an affected unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained the Administrator's prior written approval in accordance with §§ 75.23, 75.48 and 75.66.

(d) No owner or operator of an affected unit shall operate the unit so as to discharge, or allow to be discharged, emissions of SO_2, NO_x, or CO_2 to the atmosphere without accounting for all such emissions in accordance with the provisions of §§ 75.10 through 75.18.

(e) No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2, NO_x, or CO_2 emissions discharged to the atmosphere, except for periods when maintenance is performed pursuant to § 75.21 and appendix B of this part.

§75.6 Incorporation by reference.

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they existed on the date of approval, and a notice of any change in these materials will be published in the Federal Register. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Office of the Federal Register, 800 N. Capitol Street, NW., Washington, DC, at the Public Information Reference Unit of the U.S. EPA, 401 M Street, SW., Washington, DC and at the Library (MD–35), U.S. EPA, Research Triangle Park, North Carolina.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; and the University Microfilms International 300 North Zeeb Road, Ann Arbor, Michigan 48106.

(1) ASTM D129–91, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), for appendices A and D of this part.

(2) ASTM D240–87 (Reapproved 1991), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, for appendices A, D, E and F of this part.

(3) ASTM D287–82 (Reapproved 1987), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), for appendix D of this part.

(4) ASTM D388–92, Standard Classification of Coals by Rank, incorporation by reference for appendix F of this part.

(5) ASTM D941–88, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer, for appendix D of this part.

(6) ASTM D1072–90, Standard Test Method for Total Sulfur in Fuel Gases, for appendix D of this part.

(7) ASTM D1217–91, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, for appendix D of this part.

(8) ASTM D1250–80 (Reapproved 1990), Standard Guide for Petroleum Measurement Tables, for appendix D of this part.

(9) ASTM D1298–85 (Reapproved 1990), Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, for appendix D of this part.

(10) ASTM D1480–91, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, for appendix D of this part.

(11) ASTM D1481–91, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, for appendix D of this part.

(12) ASTM D1552–90, Standard Test Method for Sulfur in Petroleum Products (High Temperature Method), for appendices A and D of the part.

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

(14) ASTM D1945–91, Standard Test Method for Analysis of Natural Gas by Gas Chromatography, for appendices F and G of this part.

(15) ASTM D1946–90, Standard Practice for Analysis of Reformed Gas by Gas Chromatography, for appendices F and G of this part.

(16) ASTM D2013–86, Standard Method of Preparing Coal Samples for Analysis, for appendix F of this part.

(17) ASTM D2015–91, Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter, for appendices, A, D, E and F of this part.

(18) ASTM D2234–89, Standard Test Methods for Collection of a Gross Sample of Coal, for appendix F of this part.

(19) ASTM D2382–88, Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), for appendices D, E and F of this part.

(20) ASTM D2502–87, Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements, for appendix G of this part.

(21) ASTM D2503–82 (Reapproved 1987), Standard Test Method for Molecular Weight (Relative Molecular Mass) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, for appendix G of this part.

(22) ASTM D2622–92, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry, for appendices A and D of this part.

(23) ASTM D3174–89, Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal, for appendix G of this part.

(24) ASTM D3176–89, Standard Practice for Ultimate Analysis of Coal and Coke, for appendices A and F of this part.

(25) ASTM D3177–89, Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke, for appendix A of this part.

(26) ASTM D3178–89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, for appendix G of this part.

(27) ASTM D3238–90, Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n–d–M Method, for appendix G of this part.

(28) ASTM D4052–91, Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter, for appendix D of this part.

(29) ASTM D4057–88, Standard Practice for Manual Sampling of

Petroleum and Petroleum Products, for appendix D of this part.

(30) ASTM D4177–82 (Reapproved 1990), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, for appendix D of this part.

(31) ASTM D4239–85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, for appendix A of this part.

(32) ASTM D4294–90, Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy, for appendices A and D of this part.

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

(1) ASME MFC–3M–1989 with September 1990 Errata, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, for § 75.20 and appendices D and E of this part.

(2) ASME MFC–4M–1986 (Reaffirmed 1990), Measurement of Gas Flow by Turbine Meters, for § 75.20 and appendix E of this part.

(3) ASME MFC–5M–1985, Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, for § 75.20 and appendices D and E of this part.

(4) ASME MFC–6M–1987 with June 1987 Errata, Measurement of Fluid Flow in Pipes Using Vortex Flow Meters, for § 75.20 and appendices D and E of this part.

(5) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, for § 75.20 and appendix E of this part.

(6) ASME MFC–9M–1988 with December 1989 Errata, Measurement of Liquid Flow in Closed Conduits by Weighing Method, for § 75.20 and appendices D and E of this part.

(7) ASME Power Test Code 4.1–1964 (Reaffirmed 1991), Steam Generating Units, for appendix E of this part.

(8) ASME Performance Test Code 17–1973 (Reaffirmed 1991), Reciprocating Internal Combustion Engines, for appendix E of this part.

(9) ASME Performance Test Code 22–1985, Gas Turbine Power Plants, for appendix E of this part.

§ 75.7 EPA Study.

The Agency will initiate rulemaking to adjust the equations in the bias test by an amount sufficient to compensate for reference monitor variance based on a study, which EPA shall complete by October 31, 1993, unless the Administrator determines that adjustments are technically unnecessary or infeasible to properly determine bias.

§ 75.8 [Reserved]

Subpart B—Monitoring Provisions

§ 75.10 General operating requirements.

(a) *Primary Measurement Requirement.* The owner or operator shall measure opacity, and all SO_2, NO_x, and CO_2 emissions for each affected unit as follows:

(1) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a SO_2 continuous emission monitoring system (consisting of an SO_2 pollutant concentration monitor and a flow monitor) with the automated data acquisition and handling system for measuring and recording SO_2 concentration (in ppm), volumetric gas flow (in scfh), and SO_2 mass emissions (in lb/hr) discharged to the atmosphere, except as provided in §§ 75.11 and 75.16 and subpart E;

(2) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a NO_x continuous emission monitoring system (consisting of a NO_x pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor) with the automated data acquisition and handling system for measuring and recording NO_x concentration (in ppm) and NO_x emission rate (in lb/mmbtu) discharged to the atmosphere, except as provided in §§ 75.12 and 75.17 and subpart E;

(3) The owner or operator shall determine CO_2 emissions by using one of the following options:

(i) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a CO_2 continuous emission monitoring system (consisting of a CO_2 pollutant concentration monitor and a flow monitor) with the automated data acquisition and handling system for measuring and recording CO_2 concentration (in ppm or percent, volumetric gas flow (in scfh), and CO_2 mass emissions (in tons/hr) discharged to the atmosphere;

(ii) The owner or operator shall determine CO_2 emissions based on the measured carbon content of the fuel and the procedures in Appendix G of this part to estimate CO_2 emissions (in ton/day) discharged to the atmosphere; or

(iii) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, an O_2 concentration monitor in order to determine CO_2 emissions using the procedures in appendix F of this part to measure CO_2 emissions (in tons/hr) and to estimate CO_2 emissions (in ton/day) discharged to the atmosphere; and

(4) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements in this part, a continuous opacity monitoring system with the automated data acquisition and handling system for measuring and recording the opacity of emissions (in percent opacity) discharged to the atmosphere, except as provided in §§ 75.14 and 75.18.

(b) *Primary Equipment Performance Requirements.* The owner or operator shall ensure that each continuous emission monitoring system required by this part meets the equipment, installation, and performance specifications in Appendix A to this part; and is maintained according to the quality assurance and quality control procedures in Appendix B to this part; and shall record SO_2 and NO_x emissions in the appropriate units of measurement (i.e., lb/hr for SO_2 and lb/mmBtu for NO_x).

(c) *Heat Input Measurement Requirement.* The owner or operator shall determine and record the heat input to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in Appendix F to this part.

(d) *Primary Equipment Hourly Operating Requirements.* The owner or operator shall ensure that all continuous emission or opacity monitoring systems required by this part are in operation at all times that the affected unit combusts any fuel and that the following requirements are met:

(1) The owner or operator shall ensure that each continuous emission monitoring system and component thereof is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner or operator shall reduce all SO_2 concentrations, volumetric flow, SO_2 mass emissions, SO_2 emission rate in lb/mmBtu (if applicable), CO_2 concentration, O_2 concentration, CO_2 mass emissions (if applicable), NO_x concentration, and NO_x emission rate data to 1-hr averages. The owner or operator shall compute these averages from four or more data points equally spaced over each 1-hr period, except during periods when calibration, quality assurance, or maintenance activities pursuant to § 75.21 and appendix B of this part are being performed. During these periods, a valid hour shall consist of at least two data points separated by a minimum of 15 minutes. For combined monitoring systems (NO_x-diluent and SO_2-diluent), the hourly average emission rate is valid

only if the hourly average concentration from each of the component monitors is valid.

(2) The owner or operator shall ensure that each continuous opacity monitoring system is capable of completing a minimum of one cycle of sampling and analyzing for each successive 10-sec period and one cycle of data recording for each successive 6-min period. The owner or operator shall reduce all opacity data to 6-min averages calculated from 36 or more data points equally spaced over each 6-min period, except where the applicable State implementation plan (pursuant to part 51, Appendix M of this chapter) or operating permit requires a different averaging period, in which case the State requirement shall satisfy this Acid Rain Program requirement.

(3) Failure of an SO_2 pollutant concentration monitor, flow monitor, or NO_x continuous emission monitoring system to acquire the minimum number of data points comprising a valid hour, as specified in paragraph (d) of this section shall result in the loss of such component data for the entire hour. The owner or operator shall estimate and record emission or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in subpart D of this part.

(e) Optional Backup Monitor Requirements. If the owner or operator chooses to certify two or more continuous emission monitors or NO_x continuous emission monitoring systems that are each capable of monitoring a specific affected unit, or group of units using a common stack, then the owner or operator shall designate one such monitor or monitoring system as the primary monitor or monitoring system, and shall record this information in the monitoring plan, as provided for in § 75.53. The owner or operator shall designate the other certified monitor(s) or monitoring system(s) as the backup monitor(s) or monitoring system(s) in the monitoring plan. When the certified primary monitor or certified primary monitoring system is operating and not out-of-control as defined in § 75.24, only data from the certified primary monitor or certified primary monitoring system shall be reported as valid, quality-assured data. Thus, data from the certified backup monitor or certified backup monitoring system may be reported as valid, quality-assured data only when the backup is operating and not out-of-control as defined in § 75.24 and when the certified primary monitor or certified primary monitoring system is not operating (or is operating but out-of-control). A particular monitor may be designated both as a certified primary monitor for one unit and as a certified backup monitor for another unit.

(f) Minimum Measurement Capability Requirement. The owner or operator shall ensure that each continuous emission or opacity monitoring system and component thereof is capable of accurately measuring, recording, and reporting data, and shall not incur a full scale exceedance.

(g) Minimum Recording and Reporting Requirements. The owner or operator shall record and the designated representative shall report the hourly, daily, quarterly, and annual information collected under the requirements of this part as specified in subparts F and G of this part.

§ 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 for each affected coal-fired unit, except as provided in § 75.16 and in subpart E of this part.

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

(1) Install, operate, and maintain a continuous moisture monitor for measuring and recording the moisture content of the flue gases; or

(2) Determine the moisture content of the flue gases continuously (or on an hourly basis) and correct the measured hourly volumetric flow rates for moisture when calculating SO_2 mass emissions (in lb/hr) using the procedures in appendix F of this part.

(c) *Unit with no appropriate location for a flow monitor.* Where no location exists that satisfies the minimum physical siting criteria in appendix A to this part for installation of a flow monitor in either the stack or the ducts serving an affected unit or installation of a flow monitor in either the stack or ducts is demonstrated to the satisfaction of the Administrator to be technically infeasible, the owner or operator must either:

(1) Petition the Administrator for an alternative flow monitor location or alternative method for monitoring volumetric flow; or

(2) Construct a new stack or modify existing ductwork to accommodate the installation of a flow monitor, and petition the Administrator for an extension to the required certification date given in § 75.4 of this part. Phase I affected units may be granted an extension to January 1, 1995, for the submission of the certification application for the purpose of constructing a new stack or making substantial modifications to ductwork for installation of a flow monitor.

(d) *Gas-fired units and oil-fired units.* The owner or operator of an affected gas-fired or oil-fired unit shall measure and record SO_2 emissions using one of the following methods:

(1) Meet the general operating requirements in § 75.10 of this part for an SO_2 continuous emission monitoring system. When the owner or operator uses an SO_2 continuous emission monitoring system to monitor SO_2 mass emissions from an affected unit, the owner or operator shall comply with applicable monitoring provisions in paragraph (a) of this section; or

(2) Provide other information satisfactory to the Administrator using the procedure specified in appendix D to this part for estimating hourly SO_2 mass emissions.

(e) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions for coal-fired units specified in paragraph (a) of this section.

§ 75.12 Specific provisions for monitoring NO_x emissions (NO_x and diluent gas monitors).

(a) *Coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units.* The owner or operator shall meet the general operating requirements in § 75.10 of this part for a NO_x continuous emission monitoring system for each affected coal-fired unit, gas-fired nonpeaking unit, or oil-fired nonpeaking unit, except as provided in paragraph (c) of this section, § 75.17, and in subpart E of this part. The diluent gas monitor in the NO_x continuous emission monitoring system may measure either O_2 or CO_2 concentration in the flue gases.

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

(c) *Gas-fired peaking units or oil-fired peaking units.* The owner or operator of an affected gas-fired peaking unit or oil-fired peaking unit shall comply with the following:

(1) If a unit's operations in the previous three calendar years are no more than a capacity fact or of 20 percent in each calendar year and no

more than an average capacity factor of 10 percent, then the owner or operator shall measure and record NO_x emissions using one of the following methods:

(i) Meet the general operating requirements in § 75.10 of this part for a NO_x continuous emission monitoring system; or

(ii) Provide information satisfactory to the Administrator using the procedure specified in appendix E of this part for estimating hourly NO_x emission rate.

(2) If a unit's operations in the previous three calendar years exceed a capacity factor of 20 percent in any calendar year or exceed an average capacity factor of 10 percent, the owner or operator shall install, certify, and operate a NO_x continuous emission monitoring system by December 31 of the following calendar year.

(3) When the owner or operator of an affected gas-fired peaking unit or oil-fired peaking unit uses a NO_x continuous emission monitoring system to monitor the NO_x emission rate from the unit, the owner or operator shall comply with the applicable monitoring provisions in paragraph (a) of this section.

(d) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other material in addition to oil or gas shall comply with the monitoring provisions specified in paragraph (a) of this section.

§ 75.13 Specific provisions for monitoring CO_2 emissions.

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

(b) *Determination of CO_2 emissions using Appendix G of this part.* If the owner or operator chooses to use the appendix G method, then the owner or operator may provide information satisfactory to the Administrator for estimating daily CO_2 mass emissions based on the measured carbon content of the fuel and the amount of fuel combusted. For units with wet flue gas desulfurization systems or other add-on emissions controls generating CO_2, the owner or operator shall use the procedures in appendix G to this part to estimate both combustion-related emissions based on the measured carbon content of the fuel and the amount of fuel combusted and sorbent-related emissions based on the amount of sorbent injected. The owner or operator shall calculate daily, quarterly, and annual CO_2 mass emissions (in tons) in accordance with the procedures in appendix G to this part.

(c) *Determination of CO_2 mass emissions using appendix F of this part.* If the owner or operator chooses to use the appendix F method, then the owner or operator may estimate hourly CO_2 mass emissions based on continuous O_2 concentration monitoring, fuel F and F_c factors, and where O_2 concentration is measured on a dry basis, hourly corrections for the moisture content of the flue gases, using the methods and procedures specified in appendix F to this part. For units using a common stack the owner or operator may use the provisions of § 75.16 of this part, except that the phrase "SO_2 continuous emission monitoring system" is replaced with "CO_2 continuous emission monitoring system," the term "SO_2 concentration" is replaced with "CO_2 concentration", and the phrase "SO_2 mass emissions" is replaced with "CO_2 mass emissions."

§ 75.14 Specific provisions for monitoring opacity.

(a) *Coal-fired units and oil-fired units.* The owner or operator shall meet the general operating provisions in § 75.10 of this part for a continuous opacity monitoring system for each affected coal-fired or oil-fired unit, except as provided in paragraphs (b), (c), and (d) of this section and in § 75.18. Each continuous opacity monitoring system shall meet the design, installation, equipment, and performance specifications in Performance Specification 1 in appendix B to part 60 of this chapter. Any continuous opacity monitoring system previously certified to meet Performance Specification 1 shall be deemed certified for the purposes of this part.

(b) *Unit with wet flue gas pollution control system.* If the owner or operator can demonstrate that condensed water is present in the exhaust flue gas stream and would impede the accuracy of opacity measurements, then the owner or operator of an affected unit equipped with a wet flue gas pollution control system for SO_2 emissions or particulates is exempt from the opacity monitoring requirements of this part.

(c) *Gas-fired units.* The owner or operator of an affected gas-fired unit is exempt from the opacity monitoring requirements of this part. Whenever a unit previously categorized as a gas-fired unit is recategorized as another type of unit by changing its fuel mix, the owner or operator shall install, operate, and certify a continuous opacity monitoring system as required by paragraph (a) of this section by December 31 of the following calendar year.

(d) *Diesel-fired units and dual-fuel reciprocating engines units.* The owner or operator of an affected diesel-fired unit or a dual-fuel reciprocating engine unit is exempt from the opacity monitoring requirements of this part.

§ 75.15 Specific provisions for monitoring SO_2 emissions removal by qualifying Phase I technology.

(a) *Additional monitoring provisions.* In addition to the SO_2 monitoring requirements in § 75.11 or § 75.16, for the purposes of adequately monitoring SO_2 emissions removal by qualifying Phase I technology operated pursuant to § 72.42 of this chapter, the owner or operator shall, except where specified below, use both an inlet SO_x-diluent continuous emission monitoring and an outlet SO_2-diluent continuous emission monitoring system, consisting of an SO_2 pollutant concentration monitor and a diluent CO_2 or O_2 monitor. (The outlet SO_2-diluent continuous emission monitoring system may consist of the same SO_2 pollutant concentration monitor that is required under § 75.11 or § 75.16 for the measurement of SO_2 emissions discharged to the atmosphere and the diluent monitor used as part of the NO_x continuous emission monitoring system that is required under § 75.12 or § 75.17 for the measurement of NO_x emissions discharged into the atmosphere.) During the period when required to measure emissions removal efficiency, from January 1, 1997 through December 31, 1991, the owner or operator shall meet the general operating requirements in § 75.10 of this part for both the inlet and the outlet SO_2-diluent continuous emission monitoring systems, and in addition, the owner or operator shall comply with the monitoring provisions in this section. On January 1, 2000, the owner or operator may cease operating and/or reporting on the inlet SO_2-diluent continuous emission monitoring system results for the purposes of the Acid Rain Program.

(1) *Pre-combustion technology.* The owner or operator of an affected unit for which a precombustion technology has been employed for the purpose of

meeting qualifying Phase I technology requirements shall use Reference Method 19 in appendix A to part 60 of this chapter to estimate, daily, the percentage SO_2 removal efficiency from such technology.

(2) *Combustion technology.* The owner or operator of an affected unit for which a combustion technology has been installed and operated for the purpose of meeting qualifying Phase I technology requirements shall use the coal sampling and analysis procedures in appendix F to this part and Equation 5 in paragraph (b) of this section to estimate the percentage SO_2 removal efficiency from such technology.

(3) *Post-combustion technology.* The owner or operator of an affected unit for which a post-combustion technology has been installed and operated for the purpose of meeting qualifying Phase I technology requirements shall install, certify, operate, and maintain both an inlet and an outlet SO_2-diluent continuous emission monitoring system.

(i) Both inlet and outlet SO_2-diluent continuous emission monitoring systems shall consist of an SO_2 pollutant concentration monitor and a diluent gas monitor for measuring the O_2 or CO_2 concentrations in the flue gas and shall measure and record average hourly SO_2 emission rates (in lb/mmBtu).

(ii) The SO_2-diluent continuous emission monitoring systems for measuring and recording the SO_2 emissions removal by a qualifying Phase I technology shall meet all the requirements of this part during the period when required to measure emissions removal, from January 1, 1997 through December 31, 1999, and shall meet the certification deadline specified in § 75.4.

(iii) The SO_2 pollutant concentration monitors and the diluent gas monitors at the inlet the outlet of the SO_2 emission controls shall meet all requirements specified in appendices A and B to this part.

(b) *Demonstration of SO^2 emissions removal efficiency.* The owner or operator shall demonstrate the average annual percentage SO_2 emissions removal efficiency of the installed technology or combination of technologies during the period when required to measure emissions removal, from January 1, 1997 through December 31, 1999, according to the following procedures:

(1) Calculate the average annual SO_2 emissions removal efficiency using Equations 1–7 as follows:

$$\%R = 100[1.0-(1.0-\%R_f/100)\,(1.0-\%R_g/100)\,(1.0-\%R_c/100)] \quad (Eq.1)$$

where,

%R = Overall percentage SO_2 emissions removal efficiency.

$\%R_f$ = Percentage SO_2 emissions removal efficiency from fuel pretreatment, calculated from Equation 19–22 in Reference Method 19 in Appendix A to part 60 of this chapter.

$\%R_c$ = Percentage SO_2 emissions removal of combustion emission controls, calculated from Equation 5.

$\%R_g$ = Percentage SO_2 removal efficiency of post-combustion emission controls, calculated from Equation 2.

$$\%R_g = 100\left[1.0-\frac{E_o}{E_i}\right]$$

(Eq.2)

where,

E_o=Average hourly SO_2 emission rate in lb/mmBtu, measured at the outlet of the post-combustion emission controls during the calendar year, calculated from Equation 3.

E_i=Average hourly SO_2 emission rate in lb/mmBtu, measured at the inlet to the post-combustion emission controls during the calendar year, calculated from Equation 4.

$$E_o = \frac{\sum_{j=1}^{n} E_{hoj}}{n}$$

(Eq. 3)

where,

E_{hoj}=Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the outlet to the post-combustion emission controls.

n=Total unit operating hours during which the SO_2 continuous emission monitoring system at the outlet of the emission controls collected quality-assured data.

$$E_i = \frac{\sum_{j=1}^{m} E_{hij}}{m}$$

(Eq. 4)

where,

E_{hij}=Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the inlet to the post-combustion emission controls.

m=Total unit operating hours during which the SO_2 continuous emission monitoring system at the inlet to the emission controls collected quality-assured data.

$$\%R_c = 100\left[1.0-\frac{E_{co}}{E_{ci}}\right]$$

(Eq. 5)

where,

E_{co}=Average hourly SO_2 emission rate in lb/mmBtu, measured at the outlet of the combustion emission controls during the calendar year, calculated from Equation 6.

E_{ci}=Average hourly SO_2 emission rate in lb/mmBtu, determined by coal sampling and analysis according to the methods and procedures in Appendix G, Section 2.5.4 of this part, calculated from Equation 7.

$$E_{co} = \frac{\sum_{j=1}^{q} E_{ocj}}{q}$$

(Eq. 6)

where,

E_{ocj}=Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the outlet to the combustion controls.

q=Total unit operating hours for which the outlet SO_2 continuous emission monitoring system collected quality-assured data during the calendar year.

$$E_{ci} = \frac{\sum_{j=1}^{p} E_{icj}}{p}$$

(Eq. 7)

where,

E_{icj}=Each average hourly SO_2 emission rate in lb/mmBtu, determined by the coal sampling and analysis methods and procedures in Appendix G, Section 2.5.4 of this part and calculated using Appendix A, Method 19 of part 60 of this chapter, performed once a day.

p=Total unit operation hours during which coal sampling and analysis is performed to determine SO_2 emissions at the inlet to the combustion controls.

(2) The owner or operator shall include all periods when fuel is being combusted in determining total unit operating hours for the purpose of calculating the average SO_2 emissions removal efficiency during the calendar year.

(3) The owner or operator shall use only quality-assured SO_2 emissions data in the calculation of SO_2 emissions removal efficiency.

(4) Compliance with the 90-percent SO_2 emissions removal efficiency requirement under this part is

determined annually beginning January 1, 1997 through December 31, 1999.

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

(a) *Phase I common stack procedures.* During Phase I of the Acid Rain Program, the following procedures shall be used when more than one unit utilize a common stack:

(1) *Unit utilizing common stack with other Phase I units(s).* When a Phase I affected unit uses a common stack with one or more other Phase I affected units, but no other units, the owner or operator shall either:

(i) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct to the common stack from each affected unit; or

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the common stack; and

(A) Combine emissions for the affected units for compliance purposes; or

(B) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the Phase I affected units. The Administrator may approve such demonstrated substitute methods for apportioning SO_2 mass emissions measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(2) *Unit utilizing common stack with non-Phase I unit(s).* When one or more Phase I affected units uses a common stack with one or more Phase II or nonaffected units, the owner or operator shall either:

(i) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct to the common stack from each Phase I unit; or

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the common stack; and

(A) Designate the Phase II units as substitution units according to the procedure in part 72 of this chapter and the nonaffected units as opt-in units in accordance with the regulations implementing section 410 of the Act and combine emissions for compliance purposes; or

(B) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct from each Phase II or 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 Phase II and/or nonaffected units; and combine emissions for the Phase I affected units for compliance purposes; or

(C) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the units using the common stack. The Administrator may approve such demonstrated substitute methods for apportioning SO_2 concentration measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(b) *Phase II common stack procedures.* During Phase II of the Acid Rain Program, the following procedures shall be used when more than one unit use a common stack:

(1) *Unit utilizing common stack with other affected units(s).* When a Phase I or Phase II affected unit utilizes a common stack with one or more other Phase I or Phase II affected units, but no nonaffected units, the owner or operator shall either:

(i) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct to the common stack from each affected unit; or

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the common stack; and

(A) Combine emissions for the affected units for compliance purposes; or

(B) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the Phase I and Phase II affected units. The Administrator may approve such demonstrated substitute methods for apportioning SO_2 mass emissions measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(2) *Unit utilizing common stack with nonaffected unit(s).* When one or more Phase I or Phase II affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(i) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the duct to the common stack from Phase I and Phase II unit; or

(ii) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in the common stack; and

(A) Designate the nonaffected units as opt-in units in accordance with the regulations implementing section 410 of the Act and combine emissions for compliance purposes; or

(B) Install, certify, operate, and maintain an SO_2 continuous emission 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; and combine emissions for the Phase I and Phase II affected units for compliance purposes; or

(C) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the units using the common stack. The Administrator may approve such demonstrated substitute methods for apportioning SO_2 concentration measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(c) *Unit with by-pass stack.* When any portion of the flue gases from an affected unit can be routed so as to avoid the installed SO_2 continuous emission monitoring system, the owner or operator shall install, certify, operate, and maintain an SO_2 continuous emission monitoring system on the by-pass flue, duct, or stack gas stream.

(d) *Unit with multiple stacks.* When the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks (that may include flue gases from other affected or nonaffected units), the owner or operator shall either:

(1) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in each duct feeding into the stacks and determine SO_2 mass emissions from each affected unit as the sum of the SO_2 mass emissions measured in the ducts; or

(2) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system in each stack and develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning measured SO_2 mass emissions to each affected unit. The Administrator may approve such demonstrated substitute methods for

apportioning measured SO_2 mass emissions from multiple stacks whenever the demonstration ensures complete and accurate accounting of all emissions regulated by this part.

(e) *Heat Input.* The owner or operator of an affected unit using a common stack with a diluent monitor and a flow monitor may choose to determine the heat input for the affected unit, wherever flow and diluent monitor measurements are used to determine the heat input, using the procedures specified in paragraphs (a) through (d) of this section, except that the terms "SO_2 mass emissions" or "emissions" are replaced with the term "heat input" and the phrase "SO_2 continuous emission monitoring system" is replaced with the phrase "a diluent monitor and a flow monitor".

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

(a) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in the duct to the common stack from each affected unit; or

(2) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in the common stack and follow the appropriate procedure in paragraphs (a)(2) (i) through (iii) of this section, depending on whether or not the units are required to comply with a NO_x emission limitation (in lb/mmBtu, annual average basis) pursuant to section 407(b) of the Act (referred to hereafter as "NO_x emission limitation").

(i) When each of the affected units has a NO_x emission limitation, the designated representative shall submit a compliance plan to the Administrator that indicates:

(A) Each unit will comply with the most stringent NO_x emission limitation of any unit utilizing the common stack; or

(B) Each unit will comply with the applicable NO_x emission limitation by averaging its emissions with the other unit(s) utilizing the common stack.

(ii) When none of the affected units has a NO_x emission limitation, the owner or operator and the designated representative have no additional obligations pursuant to section 407 of the Act and may record and report a combined NO_x emission rate (in lb/mmBtu) for the affected units utilizing the common stack.

(iii) When at least one of the affected units has a NO_x emission limitation and at least one of the affected units does not have a NO_x emission limitation, the owner or operator shall either:

(a) Install, certify, operate, and maintain NO_x and diluent monitors in the ducts from the affected units; or

(B) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined NO_x emission rate (in lb/mmBtu) measured in the common stack on each of the units. The Administrator may approve such demonstrated substitute methods for apportioning NO_x emission rate measured in a common stack whenever the demonstration ensures complete and accurate estimation of all emissions regulated under this part.

(b) *Unit utilizing common stack with nonaffected units(s).* When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in the duct from each affected unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined NO_x emission rate (in lb/mmBtu) measured in the common stack for each of the units. The Administrator may approve such demonstrated substitute methods for apportioning NO_x emission rate measured in a common stack whenever the demonstration ensures complete and accurate estimation of all emissions regulated under this part.

(c) *Unit with by-pass stack.* When any portion of the flue gases from an affected unit can be routed so as to by-pass the installed NO_x continuous emission monitoring system, the owner or operator shall install, certify, operate, and maintain a NO_x continuous emission monitoring system on the by-pass flue, duct, or stack gas stream.

(d) *Unit with multiple stacks.* When the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks (that may include flue gases from other affected or nonaffected units), the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in each duct feeding into the stacks and determine the NO_x emission rate for the unit as the Btu-weighted sum of the NO_x emission rates measured in the ducts using the heat input estimation procedures in appendix F to this part; or

(2) Install, certify, operate, and maintain a NO_x continuous emission monitoring system in each stack and develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning measured NO_x emission rates to each affected unit. The Administrator may approve such demonstrated substitute methods for apportioning measured NO_x emission rates from multiple stacks whenever the demonstration ensures complete and accurate accounting of all emissions regulated by this part.

§75.18 Specific provisions for monitoring emissions from common and by-pass stacks for opacity.

(a) *Unit using common stack.* When an affected unit utilizes a common stack with other affected units or nonaffected units, the owner or operator shall comply with the applicable monitoring provision in this paragraph, as determined by existing Federal, State, or local opacity regulations.

(1) Where another regulation requires the installation of a continuous opacity monitoring system upon each affected unit, the owner or operator shall install, certify, operate, and maintain a continuous opacity monitoring system meeting Performance Specification 1 in appendix B to part 60 of this chapter (referred to hereafter as a "certified continuous opacity monitoring system") upon each unit.

(2) Where another regulation does not require the installation of a continuous opacity monitoring system upon each affected unit, and where the affected source is not subject to any existing Federal, State, or local opacity regulations, the owner or operator shall install, certify, operate, and maintain a certified continuous opacity monitoring system upon each common stack for the combined effluent.

(b) *Unit with by-pass stack.* Where any portion of the flue gases from an affected unit can be routed so as to by-pass the installed continuous opacity monitoring system, the owner or operator shall install, certify, operate, and maintain a continuous opacity monitoring system on the by-pass flue, duct, or stack gas stream.

Subpart C—Operation and Maintenance Requirements

§75.20 Certification and recertification procedures.

(a) *Initial certification approval process.* The owner or operator shall ensure that each continuous emission or opacity monitoring system required by this part, the automated data acquisition and handling system, and, where

applicable, the CO_2 continuous emission monitoring system meets the certification requirements of this section by the deadlines specified in § 75.4 of this part and prior to use in the Acid Rain Program.

(1) *Notificaiton of certification test dates or certification retesting dates.* The owner or operator or designated representative shall submit a written notice of the dates of certification testing at least 45 calendar days prior to the first day of certification testing, as specified in §§ 75.60 and 75.61.

(i) Except as provided in paragraph (a)(1)(ii) of this section, the owner or operator or designated representative shall also submit notification (or provide notification by telephone) at least 7 business days in advance of any proposed adjustments to the certification test dates.

(ii) The owner or operator may elect to repeat a certification test immediately, without advance notification, whenever the owner or operator has determined during the certification testing that a continuous emission or opacity monitoring system or component thereof has failed the test.

(2) *Certification Application.* The designated representative shall apply for certification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The designated representative shall submit the certification application in accordance with § 75.60 and each complete certification application shall include the information specified in § 75.63 of this part.

(3) *Provisional approval of certification applications.* Upon the successful completion of the required certification procedures for each continuous emission or opacity monitoring system or component thereof and subsequent submittal of a complete certification application in accordance with § 75.63, each continuous emission or opacity monitoring system or component thereof shall be deemed provisionally certified for use under the Acid Rain Program for a period not to exceed 120 days following receipt by the Administrator of the complete certification application. Data measured and recorded by a provisionally certified continuous emission or opacity monitoring system or component thereof, in accordance with the requirements of appendix B of this part, will be considered valid quality-assured data (retroactive to the date and time of completion of the certification tests), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application.

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

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

(ii) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of insufficiency. The 120-day review period shall not begin prior to receipt of a complete application.

(iii) *Disapproval notice.* If the certification application is complete but shows that any continuous emission or opacity monitoring system or component thereof does not meet the performance requirements of this part, the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification is invalidated by the Administrator, and the data measured and recorded by each uncertified continuous emission or opacity monitoring system or component thereof shall not be considered valid quality-assured data from the date and time of completion of the invalid certification tests until the date and time that the owner or operator completes subsequently approved initial certification tests. The owner or operator shall follow the loss of certification procedures in paragraph (a)(5) of this section to replace all of the invalid data for each continuous emission or opacity monitoring system or component which was disapproved.

(iv) *Audit decertifications.* Whenever an audit of a continuous emission or opacity monitoring system or component thereof or of the certification application reveals that any continuous emission or opacity monitoring system or component does not meet the performance requirements of this part (after the initial 120-day certification application review period), the Administrator may issue a notice of disapproval of the certification status of such system or component. By issuing the notice of disapproval, the certification status is invalidated, prospectively, by the Administrator, and the data measured and recorded by each continuous emission or opacity monitoring system from the date of the notification of the invalid certification status until the date and time that the owner or operator completes subsequently approved initial certification tests shall not be considered valid quality-assured data. The owner or operator shall follow the loss of certification procedures in paragraph (a)(5) of this section to replace, prospectively, all of the invalid data for each continuous emission or opacity monitoring system or component which was disapproved.

(5) *Loss of Certification Procedures.* When the Administrator issues a notice of disapproval of a certification application or a notice of disapproval of certification status, then for the period of invalid data (as specified in paragraph (a)(4) of this section), the owner or operator shall:

(i) Use the maximum potential concentration of SO_2 or NO_x, or the maximum potential velocity, as defined in section 2.1 of appendix A of this part, or the minimum O_2 concentration or maximum CO_2 concentration used to determine the maximum potential concentration of SO_2 in section 2.1.1.1 of appendix A of this part to report SO_2 concentration, NO_x concentration, calculate and report volumetric flow rate, or O_2 or CO_2 concentration data until such time, date, and hour as the continuous emission monitoring system or component thereof can be adjusted, repaired, or replaced and certification tests successfully completed (a subsequently approved initial certification); and

(ii) Ensure that the owner or operator or designated representative submits a notification of certification test dates and a new certification application according to the procedures in paragraphs (a)(1)(ii) and (a)(2) of this section, where the notification shall be provided no later than 2 business days prior to retesting for certification.

(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, including the automated data acquisition and

handling 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, the owner or operator shall recertify the continuous emission monitoring system, continuous opacity monitoring system, or component according to the procedures in this paragraph. Replacement of the analytical method, including the analyzer; change in location or orientation of the sampling probe or site; rebuilding of equipment; and analytical modifications to computer algorithms in software systems require recertification. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system that significantly affects the ability of the CEM or COM or component thereof to measure or record SO_2, NO_x, CO_2, or opacity emissions, the owner or operator shall recertify the CEM or COM or component according to the procedures in this paragraph. Recertification is not required in cases where all of the following conditions have been met: a continuous emission monitoring system has previously been certified with the same sampling location; all components of the continuous emissions monitoring system have previously been certified; and component monitors that have changed location (i.e., certified portable monitors) 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.

However, 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 or for reporting requirements under subpart G of this part.

(1) *Notification of recertification test dates.* For a recertification test, the owner or operator or designated representative shall submit the notification in accordance with the provisions in paragraph (a)(1) of this section except when recertification testing results from an emergency situation, in which case, the owner or operator or designated representative may submit notice (or provide notification by telephone) no later than 2 business days following the emergency, identifying when the testing has been or will be completed.

(2) *Recertification application.* The designated representative shall apply for recertification of a continuous emission or opacity monitoring system used under the Acid Rain Program according to the procedures in paragraph (a)(2) of this section.

(3) *Approval/disapproval of request for recertification.* The Administrator will grant provisional approval according to the procedure in paragraph (a)(3) of this section and will issue a written notice of approval or disapproval according to the procedures in paragraphs (a)(4) and (a)(5) of this section, the period for provisional certification shall not exceed 60 days following receipt of the complete recertification application by the Administrator, because the Administrator will issue a written notice of approval or disapproval within 60 days of receipt.

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

(1) For each SO_2 pollutant concentration monitor and NO_x continuous emission monitoring system:

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

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

(iii) A relative accuracy test audit;

(iv) A bias test; and

(v) A cycle time/response time test.

(2) For each flow monitor:

(i) A 7-day calibration error test;

(ii) Relative accuracy test audits at three flue gas velocities;

(iii) A bias test (at normal operating load); and

(3) The relative accuracy test audits for the SO_2 pollution concentration monitor and the flow monitor shall be performed contemporaneously.

(4) A CO_2 diluent gas monitor certified for use in a NO_x continuous emission monitoring system shall be deemed certified for the purposes of § 75.10(a)(3).

(5) For each CO_2 pollutant concentration monitor which is not certified as part of a NO_x continuous emission monitoring system and for each SO_2-diluent continuous emission monitoring system:

(i) A 7-day calibration error test, where, for the SO_2-diluent system, this test is performed separately on each component monitor;

(ii) A linearity check, where, for the SO_2 diluent system, this check is performed separately on each component monitor;

(iii) A relatively accuracy test audit; and

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

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

(ii) A continuous opacity monitoring system tested and certified previously under State or other federal requirements to meet the requirements of Performance Specification 1 shall be deemed certified for the purposes of this part.

(7) For the automated data acquisition and handling system, tests designed to verify:

(i) Proper computation of hourly averages for pollutant concentrations, flow rate, pollutant emission rates, and pollutant mass emissions; and

(ii) Proper computation and application of the missing data substitution procedures in subpart D of this part and the bias adjustment factors in Section 7 of appendix A to this part.

(8) When the optional SO_2 mass emissions estimation procedure in appendix D to this part or the optional NO_x emissions estimation protocol in appendix E 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 among the following ASME 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", or ASME MFC–9M–1988 with December 1989 Errata, "Measurement of Liquid Flow in Closed Conduits by Weighing Method", as required by appendices D and E of this part (all methods incorporated by reference under § 75.6 of this part).

(9) The owner or operator shall provide, or cause to be provided, adequate facilities for certification or recertification testing that include:

(i) Sampling ports adequate for test methods applicable to such facility, including:

(A) Volumetric flow rates, pollutant concentration, and pollutant emission rates can be accurately determined by applicable test methods and procedures; and

(B) A stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(ii) Basic facilities (i.e. electricity) for sampling and testing equipment.

(d) *Certification/recertification procedures for optional backup or portable continuous emission monitoring systems.* The owner or operator of an optional backup or an optional portable continuous emission monitoring system shall comply with all the requirements for initial certification and recertification according to the procedures specified in paragraphs (a) and (c) of this section for each backup or portable continuous emission monitoring system, except as follows: the owner or operator of a backup or portable continuous emission monitoring system may omit the 7-day calibration error test for certification or recertification of an SO_2 pollutant concentration monitor, flow monitor, NO_x pollutant concentration monitor, or diluent gas monitor, provided the backup or portable system is not used for reporting on affected unit(s) for more than 720 hours in any calendar year. Prior to each use for recording and reporting emissions, the owner or operator shall ensure that the certified backup or portable continuous emission monitoring system passes a linearity check (for pollutant concentration monitors) or a calibration error test (for flow monitors). The owner or operator shall comply with all the requirements for recertification of the backup or portable continuous emission monitoring system according to the procedures specified in paragraph (b) of this section (except that the 7-day calibration error test may be omitted) once every other year. However, when a backup or portable system is used for reporting more than 720 hours in one calendar year, it becomes a primary continuous emission monitoring system; then the owner or operator must ensure that the monitor or continuous emission monitoring system, previously considered as backup or portable, has passed all required certification tests, including the 7-day calibration error test, before valid data may be reported for more than 720 hours from any affected unit in a calendar year. Nevertheless, a portable monitor that qualifies as a reference monitor pursuant to the requirements of 40 CFR part 60, appendix A, need not be recertified prior to its use pursuant to paragraph (d) of this section.

(e) *Certification/recertification procedures for either peaking unit or by-pass stack/duct continuous emission monitoring systems.* The owner or operator of either a peaking unit or by-pass stack/duct continuous emission monitoring system shall comply with all the requirements for certification or recertification according to the procedures specified in paragraphs (a), (b), and (c) of this section, except as follows: the owner or operator need only perform one Nine-run relative accuracy test audit for certification or recertification of a flow monitor installed on the by-pass stack/duct or on the stack/duct used only by affected peaking unit(s). The relative accuracy test audit shall be performed during normal operation of the peaking unit(s) or the by-pass stack/duct.

(f) *Certification/recertification procedures for alternative monitoring systems.* The designated representative representing the owner or operator of each alternative monitoring system approved by the Administrator as equivalent to or better than a continuous emission monitoring system according to the criteria in subpart E of this part shall apply for certification to the Administrator prior to use of the system under the Acid Rain Program, and shall apply for recertification to the Administrator following a replacement, modification, or change according to the procedures in paragraph (c) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification or recertification according to the procedures specified in paragraphs (a) and (b) of this section.

(1) The Administrator will publish each request for initial certification of an alternative monitoring system in the **Federal Register** and, following a public comment period of 60 days, will issue a notice of approval or disapproval.

(2) No alternative monitoring system shall be authorized by the Administrator in a permit issued pursuant to part 72 of this chapter unless approved by the Administrator in accordance with this part.

(g) *Certification procedures for approved exceptions to CEMS.* The owner or operator of a gas-fired unit, oil-fired unit, or diesel-fired unit shall ensure that any measurement method used in lieu of a CEMS meets the general operating requirements of this part and of appendices D and E to this part, and the designated representative shall submit a certification application by the deadlines specified in § 75.4 of this part and prior to use in the Acid Rain Program.

§ 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 under the Acid Rain Program according to the quality assurance and quality control procedures in appendix B of this part.

(b) *Continuous opacity monitoring systems.* The owner or operator of an affected unit shall operate, calibrate, and maintain each continuous opacity monitoring system used under the Acid Rain Program according to the procedures specified for State Implementation Plans, pursuant to part 51, appendix M of this chapter.

(c) *Calibration gases.* The owner or operator shall ensure that all calibration gases used to quality assure the operation of the instrumentation required by this part shall meet the definition in § 72.2 of this chapter.

§ 75.22 Reference test methods.

(a) The owner or operator shall use the following methods included in appendix A to part 60 of this chapter to conduct monitoring system tests for certification or recertification of continuous emission monitoring systems and quality assurance and quality control procedures.

(1) Methods 1, or 1A are the reference methods for selection of sampling site and sample traverses.

(2) Methods 2, 2A, 2C, or 2D are the reference methods for determination of volumetric flow.

(3) Methods 3, 3A, or 3B are the reference methods for the determination of the dry molecular weight O_2 and CO_2 concentrations in the emissions.

(4) Method 4 is the reference method for the determination of moisture in the stack.

(5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E, as applicable, are the reference methods for determining SO_2 and NO_x pollutant concentrations. (Methods 6A and 6B may also be used to determine SO_2 emission rate in lb/mmBtu.)

(6) Method 20 is the reference method for determining NO_x and diluent emissions from stationary gas turbines.

§ 75.23 Alternatives to ASTM methods.

(a) The designated representative of a unit may petition the Administrator for an alternative to any ASTM method prescribed in this part.

(b) The designated representative shall include the following information in the petition for use of an alternative method:

(1) A description of why the prescribed ASTM method is not being used or cannot be used;

(2) A description and diagram(s) of all equipment and procedures in the proposed alternative method;

(3) Data demonstrating that the proposed alternative method produces data of equal or greater precision and accuracy to that from the prescribed ASTM method(s).

§ 75.24 Out-of-control periods.

(a) If an out-of-control period occurs to a monitor or continuous emission monitoring system, the owner or operator shall take corrective action and repeat the tests applicable to the "out-of-control parameter" as described in appendix B of this part.

(1) For daily calibration error tests, an out-of-control period occurs when the calibration error of a pollutant concentration monitor exceeds 5.0 percent based upon the span value, the calibration error of a diluent gas monitor exceeds 1.0 percent O_2 or CO_2, or the calibration error of a flow monitor exceeds 6.0 percent based upon the span value, which is twice the applicable specification in Appendix A to this part.

(2) For quarterly linearity checks, an out-of-control period occurs when the error in linearity at any of three gas concentrations (low, mid-range, and high) exceeds the applicable specification in appendix A to this part.

(3) For relative accuracy test audits, an out-of-control period occurs when the relative accuracy exceeds the applicable specification in Appendix A to this part.

(b) When a monitor or continuous emission monitoring system is out-of-control, any data recorded by the monitor or monitoring system are not quality-assured and shall not be used in calculating monitor data availabilities pursuant to § 75.32 of this part.

(c) When a monitor or continuous emission monitoring system is out-of-control, the owner or operator shall take one of the following actions until the monitor or monitoring system has successfully met the relevant criteria in appendices A and B of this part as demonstrated by subsequent tests:

(1) Apply the procedures for missing data substitution to emissions from affected unit(s); or

(2) Use a certified backup or certified portable monitor or monitoring system or a reference method for measuring and recording emissions from the affected unit(s); or

(3) Adjust the gas discharge paths from the affected unit(s) with emissions normally observed by the out-of-control monitor or monitoring system so that all exhaust gases are monitored by a certified monitor or monitoring system meeting the requirements of appendices A and B of this part.

(d) When the bias test indicates a monitor or monitoring system is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test or calculate and use the bias adjustment factor as specified in section 2.3.3 of appendix B to this part and in accordance with § 75.7.

(e) The owner or operator shall determine if a continuous opacity monitoring system is out-of-control and shall take appropriate corrective actions according to the procedures specified for State Implementation Plans, pursuant to 40 CFR part 51, appendix M. When repeated out-of-control periods occur to a continuous opacity monitoring system, causing the monitor data availability of the system to fall below 90.0 percent, the owner or operator shall either:

(1) Use a certified backup continuous opacity monitoring system for measuring and recording opacity from the affected unit(s); or

(2) Use the procedures in Method 9 in appendix A to part 60 of this chapter to measure the opacity of emissions discharged to the atmosphere from the affected unit(s).

Subpart D—Missing Data Substitution Procedures

§ 75.30 General provisions.

(a) Except as provided in § 75.34 of this subpart, the owner or operator shall provide substitute data for each affected unit according to the missing data procedures in this subpart whenever the unit combusts any fuel and:

(1) A valid hour of SO_2 concentration data (in ppm) has not been measured and recorded for an affected unit by a certified SO_2 pollutant concentration monitor, or by an approved alternative monitoring method under subpart E of this part; or

(2) A valid hour of flow data (in scfh) has not been measured and recorded for an affected unit from a certified flow monitor, or by an approved alternative monitoring system under subpart E of this part; or

(3) A valid hour of NO_x emission rate data (in lb/mmBtu) has not been measured and recorded for an affected unit by a certified NO_x continuous emission monitoring system, or by an approved alternative monitoring system under subpart E of this part.

(b) However, the owner or operator shall have no need to provide substitute data according to the missing data procedures in this subpart if the owner or operator uses SO_2 concentration, flow, or NO_x emission rate data recorded from a certified backup or certified portable continuous emission monitor or a reference method when the certified primary monitor is down or out-of-control, provided that the backup or portable monitor has been certified according to the procedures in § 75.20 of this part prior to the missing data period, and provided that the backup or portable monitor passes a linearity check (for pollutant concentration monitors) or a calibration error test (for flow monitors) prior to each period of use of the certified backup monitor or certified portable monitor for recording and reporting emissions. Such use of certified portable monitor, certified backup monitor, or reference method is optional and at the discretion of the owner or operator.

(c) When the certified primary monitor is down or out-of-control, then data recorded for an affected unit from a certified backup or certified portable continuous emission monitor are used, as if such data were from the certified primary monitor, to calculate monitor data availability in § 75.32, and to provide the quality-assured data used in

the missing data procedures in §§ 75.31 and 75.33, such as the "hour after" value.

§ 75.31 Initial missing data procedures.

(a) During the first 720 quality-assured monitor operating hours following initial certification (i.e., beginning from the date and time of completion of successful certification tests), of the SO_2 pollutant concentration monitor and during the first 2,160 quality-assured monitor operating hours following initial certification of the flow monitor and NO_x continuous emission monitoring system(s), the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section.

(b) *SO_2 concentration data.* For each hour of missing SO_2 concentration data, the owner or operator shall calculate the substitute data as follows:

(1) Whenever prior quality assured data exist, the owner or operator shall substitute, by means of the data acquisition and handling system, the average of the hourly SO_2 concentrations recorded for an affected unit by a certified monitor for the unit operating hour immediately before and the unit operating hour immediately after the missing data period for each hour of missing data (henceforth referred to as "the hour before and after").

(2) Whenever no prior quality-assured SO_2 concentration data exist, the owner or operator shall substitute the maximum potential concentration for SO_2, as specified in section 2.1 of appendix A, for each hour of missing data.

(c) *Volumetric flow and NO_x emission rate data.* For each hour of missing volumetric flow or NO_x emission rate data;

(1) Whenever prior quality-assured data exist in the load range corresponding to the operating load at the time the missing data period occurred, the owner or operator shall substitute, by means of the automated data acquisition and handling system, the average hourly flow rate (or NO_x emission rate) recorded for the affected unit by a certified flow monitor (or a certified NO_x continuous emission monitoring system). The flow rate (or NO_x emission rate) shall be calculated from the corresponding load range as determined using the procedure in appendix C of this part.

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

(3) Whenever no prior quality-assured flow or NO_x emission rate data exist for any load range, the owner or operator shall use the maximum potential velocity to calculate and substitute the maximum flow rate or shall substitute the maximum potential NO_x emission rate, as specified in section 2.1 of appendix A, for each hour of missing data.

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

(a) Following initial certification, upon completion of the first 720 quality-assured monitor operating hours of the SO_2 pollutant concentration monitor or the first 2,160 quality-assured monitor operating hours of the flow monitor or NO_x continuous emission monitoring system, the owner or operator shall calculate and record, by means of the automated data acquisition and handling system, the percent monitor data availability for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x continuous emission monitoring system as follows:

(1) Prior to completion of 8,760 unit operating hours following initial certification, the owner or operator shall, for the purpose of applying the standard missing data procedures of § 75.33, use Equation 8 to calculate, hourly, percent monitor data availability.

$$\text{Percent monitor data availability} = \frac{\text{Total unit operating hours for which quality-assured data were recorded since certification}}{\text{Total unit operating hours since certification}} \times 100 \quad \text{(Eq. 8)}$$

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

(2) Upon completion of 8,760 unit operating hours following initial certification and thereafter, the owner or operator shall, for the purpose of applying the standard missing data procedures of § 75.33, use Equation 9 to calculate, hourly, percent monitor data availability.

(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 backup monitor, a certified portable monitor, and a reference method for that unit, and from an approved alternative monitoring system under subpart E of this part when calculating percent monitor data availability using Equation 8 or 9.

(b) Although the monitor data availability need not be recorded during the missing data period, then the owner or operator shall record the percent monitor data availability at the end of each missing data period, (and thereafter, continue to record monitor data availability hourly, pursuant to § 75.50).

§ 75.33 Standard missing data procedures.

(a) Following initial certification and upon completion of the first 720 quality-assured monitor operating hours of the SO_2 pollutant concentration monitor or the first 2,160 quality-assured monitor operating hours of the flow monitor or NO_x continuous emission monitoring

system, the owner or operator shall provide substitute data required under this subpart according to the procedures in paragraphs (b) and (c) of this section and depicted in Table 1 (SO_x) and Table 2 (NO_x, flow).

TABLE 1.—MISSING DATA PROCEDURE FOR SO_2 CEMS

Trigger conditions		Calculation routines	
Availability (percent)	Duration (N) of outage (hours)	Method	Lookback period
95 or more	N≤24	Average	HB/HA.
	N>24	Max. of average	HB/HA.
		Max. of 90th percentile	720 operating hours *.
90 or more, but below 95	N≤8	Average	HB/HA.
	N>8	Max. of average	HB/HA.
		Max. of 95th percentile	720 operating hours *.
Below 90	N >0	Maximum value [1]	720 operating hours *.

HB/HA=hour before and hour after the outage.
*=Quality-assured, monitor operating hours.
[1] Where unit with add-on emission controls can demonstrate that the controls are operating properly, as provided in §75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 720 operating hours.

TABLE 2.—MISSING DATA PROCEDURE FOR NO_x AND FLOW CEMS

Trigger conditions		Calculation routines		
Availability (percent)	Duration (N) of outage (hours)	Method	Lookback period	Load ranges
95 or more	N ≤ 24	Average	2160 operating hours*	Yes.
	N > 24	Max of average	HB/HA	No.
		Max of 90th percentile	2160 operating hours*	Yes.
90 or more, but below 95	N ≤ 8	Average	2160 operating hours*	Yes.
	N > 8	Max of Average	HB/HA	No.
		Max of 95th percentile	2160 operating hours*	Yes.
Below 90	N > 0	Maximum Value[1]	2160 operating hours*	Yes.

HB/HA = hour before and hour after the outage.
* = Quality-assured, monitor operating hours.
[1] Where unit with add-on emission controls can demonstrate that the controls are operating properly, as provided in §75.34, the unit may, upon approval, use the maximum controlled emission rate from the previous 720 operating hours.

(b) *SO_2 concentration data.* For each hour of missing SO_2 concentration data,

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

(i) For a missing data period less than or equal to 24 hours, substitute the average of the hourly SO_2 concentrations recorded by an SO_2 pollutant concentration monitor for the hour before and the hour after the missing data period.

(ii) For a missing data period greater than 24 hours, substitute the greater of:

(A) The 90th percentile hourly SO_2 concentration recorded by an SO_2 pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or

(B) The average of the hourly SO_2 concentrations recorded by an SO_2 pollutant concentration monitor for the hour before and the hour after the missing data period.

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

(i) For a missing data period of less than or equal to 8 hours, substitute the average of the hourly SO_2 concentrations recorded by an SO_2 pollutant concentration monitor for the hour before and the hour after the missing data period.

(ii) For a missing data period of more than 8 hours, substitute the greater of:

(A) the 95th percentile hourly SO_2 concentration recorded by an SO_2 pollutant concentration monitor during the previous 720 quality-assured monitor operating hours; or

(B) The average of the hourly SO_2 concentrations recorded by an SO_2 pollutant concentration monitor for the hour before and the hour after the missing data period.

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

(c) *Volumetric flow and NO_x emission rate data.* For each hour of missing volumetric flow or NO_x emission rate data,

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

(i) For a missing data period less than or equal to 24 hours, substitute the average hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system during the previous 2,160 quality-assured monitor operating hours at the corresponding unit load range recorded for each missing hour, as determined using the procedure in Appendix C to this part.

(ii) For a missing data period greater than 24 hours, substitute the greater of:

(A) The 90th percentile hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system at the corresponding

unit load range recorded for each missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in appendix C to this part; or

(B) The average of the hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system for the hour before and the hour after the missing data period.

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

(i) For a missing data period of less than or equal to 8 hours, substitute the average hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system at the corresponding unit load range recorded for the missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in appendix C to this part.

(ii) For a missing data period greater than 8 hours, substitute the greater of:

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

(B) The average of the hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system for the hour before and the hour after the missing data period.

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

(i) For a missing data period of less than or equal to 8 hours, substitute the average hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system at the corresponding unit load range recorded for the missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in appendix C to this part.

(ii) For a missing data period greater than 8 hours, substitute the greater of:

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

(B) The average of the hourly flow or NO_x emission rate recorded by a flow monitor or NO_x continuous emission monitoring system for the hour before and the hour after the missing data period.

(3) Whenever the monitor data availability is less than 90.0 percent, the owner or operator shall calculate substitute data by means of the automated data acquisition and handling system for each hour of each missing data period by substituting the maximum hourly flow or NO_x emission rate recorded by the flow monitor or NO_x continuous emission monitoring system at the corresponding unit load range recorded for the missing hour during the previous 2,160 quality-assured monitor operating hours, as determined using the procedure in Section 2 of Appendix C to this part.

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

§ 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 may choose one of the following options:

(1) The owner or operator may use the missing data routine as specified for all affected units in §§ 75.31 through 75.33. In addition, the owner or operator may petition the Administrator 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. The owner or operator 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 percent and parametric monitors can establish that the add-on emission controls were operating properly during the time period under petition.

(2) The owner or operator 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 this section and of appendix C to this part.

(b) For an affected unit equipped with add-on SO_2 emission controls, the owner or operator 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) of this part for providing substitute data for missing SO_2 concentration data unless a parametric monitoring procedure has been approved by the Administrator.

(1) Where the monitoring 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.

(2) Where the monitor data availability for an outlet SO_2 pollutant concentration monitor is less than 90.0 percent, the owner or operator shall calculate substitute data using the procedures in § 75.33(b)(3) or § 75.34(a) of this part, even if the Administrator has approved a parametric monitoring procedure.

(c) For an affected unit with NO_x add-on emission controls, the owner or operator 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 of this part for providing substitute data for missing NO_x emission rate data prior to receiving the Administrator's approval for a parametric monitoring procedure.

(1) Where monitor data availability for a NO_x continuous emission monitoring system is 90.0 percent or more, the owner or operator may calculate substitute data using an approved parametric monitoring procedure.

(2) Where monitor data availability for a NO_x continuous emission monitoring system is less than 90.0 percent, the owner or operator shall calculate substitute data using the procedure in § 75.33(c)(3) or petition in accordance with § 75.34(a)(1) of this part, even if the

Administrator has approved a parametric monitoring procedure.

(d) The owner or operator shall provide information as described in subparts F and G of this part to verify the proper operation of the SO_2 or NO_x emission controls during all periods of missing data. Whenever such data are not provided or proper operation of the SO_2 or NO_x emission controls has not been maintained, the owner or operator shall substitute the maximum potential concentration for NO_x, as defined in section 2.1 of Appendix A, and the minimum O_2 concentration or maximum O_2 concentration used to determine the maximum potential concentration of SO_2 in section 2.1.1.1 of appendix A in calculations of NO_x emission rate or the maximum hourly SO_2 concentration recorded by the inlet monitor during the previous 720 quality assured monitor operating hours for each hour of missing data until parametric data demonstrating proper operation of the SO_2 or NO_x emission controls are available.

Subpart E—Alternative Monitoring Systems

§75.40 General demonstration requirements.

(a) The owner or operator of an affected unit, or the owner or operator of an affected unit and representing a class of affected units which meet the criteria specified in § 75.47, required to install a continuous emission monitoring system may apply to the Administrator for approval of an alternative monitoring system (or system component) to determine average hourly emission data for SO_2, NO_x, and/or volumetric flow by demonstrating that the alternative monitoring system has the same or better precision, reliability, accessibility, and timeliness as that provided by the continuous emission monitoring system.

(b) The requirements of this subpart shall be met by the alternative monitoring system when compared to a contemporaneously operating, fully certified continuous emission monitoring system or a contemporaneously operating reference method, where the appropriate reference methods are listed in § 75.22.

§75.41 Precision criteria.

(a) *Data collection and analysis.* To demonstrate precision equal to or better than the continuous emission monitoring system, the owner or operator shall conduct an F-test, a correlation analysis, and a t-test for bias as described in this section. The t-test shall be performed only on sample data at the normal operating level and primary fuel supply, whereas the F-test and the correlation analysis must be performed on each of the data sets required under paragraphs (a)(4) and (a)(5) of this section. The owner or operator shall collect and analyze data according to the following requirements:

(1) Data from the alternative monitoring system and the continuous emission monitoring system shall be collected and paired in a manner that ensures each pair of values applies to hourly average emissions during the same hour.

(2) An alternative monitoring system that directly measures emissions shall have probes or other measuring devices in locations that are in proximity to the continuous emission monitoring system and shall provide data on the same parameters as those measured by the continuous emission monitoring system. Data from the alternative monitoring system shall meet the statistical tests for precision in paragraph (c) of this section and the t-test for bias in appendix A of this part.

(3) An alternative monitoring system that indirectly quantifies emission values by measuring inputs, operating characteristics, or outputs and then applying a regression or another quantitative technique to estimate emissions, shall meet the statistical tests for precision in paragraph (c) of this section and the t-test for bias in Appendix A of this part.

(4) For flow monitor alternatives, the alternative monitoring system must provide sample data for each of three different exhaust gas velocities while the unit or units, if more than one unit exhausts into the stack or duct, is burning its primary fuel at:

(i) A frequently used low operating level, selected within the range between the minimum safe and stable operating level and 50 percent of the maximum operating level,

(ii) A frequently used high operating level, selected within the range between 80 percent of the maximum operating level and the maximum operating level, and

(iii) The normal operating level, or an evenly spaced intermediary level between low and high levels used if the normal operating level is within a specified range, (10.0 percent of the maximum operating level) of either (a)(4) (i) or (ii) of this section.

(5) For pollutant concentration monitor alternatives, the alternative monitoring system shall provide sample data for the primary fuel supply and for all alternative fuel supplies that have significantly different sulfur content.

(6) For the normal unit operating level and primary fuel supply, paired hourly sample data shall be provided for at least 90.0 percent of the hours during 720 unit operating hours. For each of the remaining two operating levels for flow monitor alternatives, and for each alternative fuel supply for pollutant concentration monitor alternatives, paired hourly sample data shall be provided for at least 24 successive unit operating hours.

(7) The owner or operator shall not use missing data substitution procedures to provide sample data.

(8) If the collected data meet the requirements of the F-test, the correlation test, and the t-test at one or more, but not all, of the operating levels or fuel supplies, the owner or operator may elect to continue collecting the paired data for up to 1,440 additional operating hours and repeat the statistical tests using the data for the entire 30- to 90-day period.

(9) The owner or operator shall provide two separate time series data plots for the data at each operating level or fuel supply described in paragraphs (a)(4) and (a)(5) of this section. Each data plot shall have a horizontal axis that represents the clock hour and calendar date of the readings and shall contain a separate data point for every hour for the duration of the performance evaluation. The data plots shall show the following:

(i) Percentage difference versus time where the vertical axis represents the percentage difference between each paired hourly reading generated by the continuous emission monitoring system and the alternative emission monitoring system as calculated using the following equation:

$$\Delta e = \frac{e_p - e_v}{e_v} \times 100\%$$

(Eq.10)

where,

Δe=Percentage difference between the readings generated by the alternative monitoring system and the continuous emission monitoring system.

e_p=Measured value from the alternative monitoring system.

e_v=Measured value from the continuous emission monitoring system.

(ii) Alternative monitoring system readings and continuous emissions monitoring system readings versus time where the vertical axis represents

hourly pollutant concentrations or volumetric flow, as appropriate, and two different symbols are used to represent the readings from the alternative monitoring system and the continuous emission monitoring system, respectively.

(b) *Data screening and calculation adjustments.* In preparation for conducting the statistical tests, described in paragraph (c) of this section, the owner or operator may screen the data for lognormality and time dependency autocorrelation. If either is detected, the owner or operator shall make the following calculation adjustments:

(1) *Lognormality.* The owner or operator shall conduct any screening and adjustment for lognormality according to the following procedures.

(i) Apply the log transformation to each measured value of either the certified continuous emissions monitoring system or certified flow monitor, using the following equation:

$l_v = \ln e_v$

where,

e_v=Hourly value generated by the certified continuous emissions monitoring system or certified flow monitoring system

l_v=Hourly lognormalized data values for the certified monitoring system

and to each measured value, e_p, of the proposed alternative monitoring system, using the following equation to obtain the lognormalized data values, l_p:

$l_p = \ln e_p$

where,

e_p=Hourly value generated by the proposed alternative monitoring system.

l_p=Hourly lognormalized data values for the proposed alternative monitoring system.

(ii) Separately test each set of transformed data, l_v and l_p, for normality, using the following:

(A) Shapiro-Wilk test;

(B) Histogram of the transformed data; and

(C) Quantile-Quantile plot of the transformed data.

(iii) The transformed data in a data set will be considered normally distributed if all of the following conditions are satisfied:

(A) The Shapiro-Wilk test statistic, W, is greater than or equal to 0.75 or is not statistically significant at α=0.05.

(B) The histogram of the data is unimodal and symmetric.

(C) The Quantile-Quantile plot is a diagonal straight line.

(iv) If both of the transformed data sets, l_v and l_p, meet the conditions for normality, specified in paragraphs (b)(1)(iii) (A) through (C) of this section, the owner or operator may use the transformed data, l_v and l_p, in place of the original measured data values in the statistical tests for alternative monitoring systems as described in paragraph (c) of this section and in appendix A of this part.

(v) If the transformed data are used in the statistical tests in paragraph (c) of this section and in appendix A of this part, the owner or operator shall provide the following:

(A) Copy of the original measured values and the corresponding transformed data in printed and electronic format.

(B) Printed copy of the test results and plots described in paragraphs (b)(1) (i) through (iii) of this section.

(2) *Time dependency (autocorrelation).* The screening and adjustment for time dependency are conducted according to the following procedures:

(i) Calculate the degree of autocorrelation of the data on their LAG1 values, where the degree of autocorrelation is represented by the Pearson autocorrelation coefficient, ρ, computed from an AR(1) autoregression model, such that where,

$$\rho = \frac{COV(x_i', x_i'')}{S_{x_i'} S_{x_i''}}$$

(Eq. 13)

X'_i=The original data value at i.

X''_i=The LAG1 data value at hour i.

$COV(X'_i, X''_i)$=The autocovariance of X'_i and defined by,

$$COV(x_i', x_i'') = \frac{\sum_{i=1}^{n} (x_i' - \overline{x}')(x_i'' - \overline{x}'')}{(n-1)}$$

(Eq. 14)

n=The total number of observations in which both the original value, X'_i, and the lagged value, X''_i, are available in the data set.

S'_{x_i}=The standard deviation of the original data values, X'_i defined by,

$$S_{x_i'} = \sqrt{\frac{\sum_{i=1}^{n} (x_i' - \overline{x}')^2}{n-1}}$$

(Eq. 15)

S''_{x_i}=The standard deviation of the LAG1 data values, X''_i, defined by

$$S_{x_i''} = \sqrt{\frac{\sum_{i=1}^{n} (x_i'' - \overline{x}'')^2}{n-1}}$$

(Eq. 16)

$\overline{X}'$=The mean of the original data values, X'_i defined by

$$\overline{x}' = \frac{\sum_{i=1}^{n} x_i'}{n}$$

(Eq. 17)

$\overline{X}''$=The mean of the LAG1 data values, X''_i, defined by

$$\overline{x}'' = \frac{\sum_{i=1}^{n} x_i''}{n}$$

(Eq. 18)

(ii) The data in a data set will be considered autocorrelated if the autocorrelation coefficient, ρ, is significant at the 5 percent significance level. To determine if this condition is satisfied, calculate Z using the following equation:

$$Z = 0.5\left[\ln\left(\frac{1+\rho}{1-\rho}\right)\right]\sqrt{n-3}$$

(Eq. 19)

If $Z > 1.96$, then the autocorrelation coefficient, ρ, is significant at the 5 percent significance level ($\alpha = 0.05$).

(iii) If the data in a data set satisfy the conditions for autocorrelation, specified in paragraph (b)(2)(ii) of this section, the variance of the data, S^2, may be adjusted using the following equation:

$S^2_{adj} = VIF \times S^2$

(Eq. 20)

where,

S^2=The original, unadjusted variance of the data set.

VIF=The variance inflation factor, defined by

$$VIF = \frac{1}{\left[1 - \frac{2\rho}{(n-1)(1-\rho)} + \frac{2\rho(1-\rho^n)}{n(n-1)(1-\rho)^2}\right]}$$

(Eq. 21)

S^2_{adj}=The autocorrelation-adjusted variance for the data set.

(iv) The procedures described in paragraphs (b)(2)(i)–(iii) of this section may be separately applied to the following data sets in order to derive distinct autocorrelation coefficients and variance inflation factors for each data set:

(A) The set of measured hourly values, e_v, generated by the certified continuous emissions monitoring system or certified flow monitoring system.

(B) The set of hourly values, e_p, generated by the proposed alternative monitoring system,

(C) The set of hourly differences, $e_v - e_p$, between the hourly values, e_v, generated by the certified continuous emissions monitoring system or certified flow monitoring system and the hourly values, e_p, generated by the proposed alternative monitoring system.

(v) For any data set, listed in paragraph (b)(2)(iv) of this section, that satisfies the conditions for autocorrelation specified in paragraph (b)(2)(ii) of this section, the owner or operator may adjust the variance of that data set, using Equation 20 of this section.

(A) The adjusted variance may be used in place of the corresponding original variance in the F-test Equation 23 of this section.

(B) In place of the standard error of the mean,

$$\frac{S_d}{\sqrt{n}},$$

in the bias test Equation A–9 of Appendix A the following adjusted standard error of the mean may be used:

$$\left(\frac{S_d}{\sqrt{n}}\right)_{adj} = \left[\sqrt{\left(\frac{1+\rho}{1-\rho}\right) - \left(\frac{2\rho(1-\rho^n)}{n(1-\rho)^2}\right)}\right] \times \sqrt{VIF} \times \left(\frac{S_d}{\sqrt{n}}\right) \qquad \text{(Eq. 22)}$$

where,

$\left(\frac{S_d}{\sqrt{n}}\right)_{adj}$ = The autocorrelation-adjusted standard error of the mean.

(vi) For each data set in which a variance adjustment is used, the owner or operator shall provide the following:

(A) All values in the data set in printed and electronic format.

(B) Values of the autocorrelation coefficient, its level of significance, the variance inflation factor, and the unadjusted original and adjusted values found in Equations 20 and 22 of this section.

(C) Equation and related statistics of the AR(1) autoregression model of the data set.

(D) Printed documentation of the intermediate calculations used to derive the autocorrelation coefficient and the Variance Inflation Factor.

(c) *Statistical Tests.* The owner or operator shall perform the F-test and correlation analysis as described in this paragraph and the t-test for bias described in Appendix A of this part to demonstrate the precision of the alternative monitoring system.

(1) *F-test.* The owner or operator shall conduct the F-test according to the following procedures.

(i) Calculate the variance of the certified continuous emission monitoring system or certified flow monitor as applicable, S_v^2, and the proposed method, S_p^2, using the following equation.

$$S^2 = \frac{\sum_{i=1}^{n} (e_i - e_m)^2}{n-1}$$

(Eq. 23)

where,

e_i = Measured values of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method.

e_m = Mean of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method values.

n = Total number of paired samples.

(ii) Determine if the variance of the proposed method is significantly different from that of the certified continuous emission monitoring system or certified flow monitor, as applicable, by calculating the F-value using the following equation.

$$F = \frac{S_p^2}{S_v^2}$$

(Eq. 24)

Compare the experimental F-value with the critical value of F at the 95-percent confidence level with n-1 degrees of freedom. The critical value is obtained from a table for F-distribution. If the calculated F-value is greater than the critical value, the proposed method is unacceptable.

(2) *Correlation analysis.* The owner or operator shall conduct the correlation analysis according to the following procedures.

(i) Plot each of the paired emissions readings as a separate point on a graph where the vertical axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the alternative monitoring system and the horizontal axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the continuous emission monitoring system. On the graph, draw a horizontal line representing the mean value, e_p, for the

alternative monitoring system and a vertical line representing the mean value, e_v, for the continuous emission monitoring system where,

$$\overline{e_p} = \frac{\sum e_p}{n}$$

(Eq. 25)

$$\overline{e_v} = \frac{\sum e_v}{n}$$

(Eq. 26)

where,

e_p=Hourly value generated by the alternative monitoring system.

e_v=Hourly value generated by the continuous emission monitoring system.

n=Total number of hours for which data were generated for the tests.

A separate graph shall be produced for the data generated at each of the operating levels or fuel supplies described in paragraphs (a)(4) and (a)(5) of this section.

(ii) Use the following equation to calculate the coefficient of correlation, r, between the emissions data from the alternative monitoring system and the continuous emission monitoring system using all hourly data for which paired values were available from both monitoring systems.

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

(Eq. 27)

(iii) If the calculated r-value is less than 0.8, the proposed method is unacceptable.

§ 75.42 Reliability criteria.

To demonstrate reliability equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system is capable of providing valid 1-hr averages for 95.0 percent or more of unit operating hours over a 1-yr period and that the system meets the applicable requirements of Appendix B of this part.

§ 75.43 Accessibility criteria.

To demonstrate accessibility equal to or better than the continuous emission monitoring system, the owner or operator shall provide reports and onsite records of emission data to demonstrate that the alternative monitoring system provides data meeting the requirements of subparts F and G of this part.

§ 75.44 Timeliness criteria.

To demonstrate timeliness equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system can meet the requirements of subparts F and G of this part; can provide a continuous, quality-assured, permanent record of certified emissions data on an hourly basis; and can issue a record of data for the previous day within 24 hours.

§ 75.45 Daily quality assurance criteria.

The owner or operator shall either demonstrate that daily tests equivalent to those specified in Appendix B of this part can be performed on the alternative monitoring system or demonstrate and document that such tests are unnecessary for providing quality-assured data.

§ 75.46 Missing data substitution criteria.

The owner or operator shall demonstrate that all missing data can be accounted for in a manner consistent with the applicable missing data procedures in subpart D of this part.

§ 75.47 Criteria for a class of affected units.

(a) The owner or operator of an affected unit may represent a class of affected units for the purpose of applying to the Administrator for a class-approved alternative monitoring system.

(b) The owner or operator of an affected unit representing a class of affected units shall provide the following information:

(1) A description of the affected unit and how it appropriately represents the class of affected units;

(2) A description of the class of affected units, including data describing all the affected units which will comprise the class; and

(3) A demonstration that the magnitude of emissions of all units which will comprise the class of affected units are *de minimis*.

(c) If the Administrator determines that the emissions from all affected units which will comprise the class of units are *de minimis*, then the Administrator shall publish notice in the **Federal Register**, providing a 30-day period for public comment, prior to granting a class-approved alternative monitoring system.

§ 75.48 Petition for an alternative monitoring system.

(a) The designated representative shall submit the following information in the application for certification or recertification of an alternative monitoring system.

(1) Source identification information.

(2) A description of the alternative monitoring system.

(3) Data, calculations, and results of the statistical tests, specified in § 75.41(c) of this part, including:

(i) Date and hour.

(ii) Hourly test data for the alternative monitoring system at each required operating level and fuel type.

(iii) Hourly test data for the continuous emissions monitoring system at each required operating level and fuel type.

(iv) Arithmetic mean of the alternative monitoring system measurement values, as specified in Equation 24 in § 75.41(c) of this part, of the continuous emission monitoring system values, as specified on Equation 25 in § 75.41(c) of this part, and of their differences.

(v) Standard deviation of the difference, as specified in Equation A–8 in Appendix A to this part.

(vi) Confidence coefficient, as specified in Equation A–9 in Appendix A to this part.

(vii) The bias test results as specified in § 7.6.4 in Appendix A to this part.

(viii) Variance of the measured values for the alternative monitoring system and of the measured values for the continuous emissions monitoring system, as specified in Equation 22 in § 75.41(c) of this part.

(ix) F-statistic, as specified in Equation 23 in § 75.41(c) of this part.

(x) Critical value of F at the 95-percent confidence level with n-1 degrees of freedom.

(xi) Coefficient of correlation, r, as specified in Equation 26 in § 75.41(c) of this part.

(4) Data plots, specified in §§ 75.41(a)(9) and 75.41(c)(2)(i) of this part.

(5) Results of monitor reliability analysis.

(6) Results of monitor accessibility analysis.

(7) Results of monitor timeliness analysis.

(8) A detailed description of the process used to collect data, including location and method of ensuring an accurate assessment of operating hourly conditions on a real-time basis.

(9) A detailed description of the operation, maintenance, and quality assurance procedures for the alternative monitoring system as required in Appendix B of this part.

(10) A description of methods used to calculate heat input or diluent gas concentration, if applicable.

(11) Results of tests and measurements (including the results of all reference method field test sheets, charts, laboratory analyses; example calculations, or other data as appropriate) necessary to substantiate that the alternative monitoring system is equivalent in performance to an appropriate, certified operating continuous emission monitoring system.

Subpart F—Recordkeeping Requirements

§75.50 General recordkeeping provisions.

(a) *Recordkeeping requirements for affected sources.* The owner or operator of any affected source subject to the requirements of this part shall maintain for each affected unit [or for each group of affected or nonaffected units utilizing a common stack and common monitoring systems pursuant to § 75.16–§ 75.18 of this part (referred to hereafter as "each affected unit")] a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. This file shall contain the following information:

(1) The data and information required in paragraphs (b) through (f) of this section;

(2) The component data and information used to calculate values required in paragraphs (b) through (f) of this section;

(3) The current monitoring plan as specified in § 75.53 of this part; and

(4) The quality control plan as described in Appendix B to this part.

(b) *Operating parameter record provisions.* The owner or operator shall record hourly the following information on unit operating time, heat input, and load for each affected unit, including individual affected units utilizing a common stack except as provided in paragraph (b)(6) of this section for gas-fired units.

(1) Date and hour;

(2) Unit operating time (rounded to nearest hour);

(3) Total integrated hourly gross unit load (rounded to nearest MW_{ge}) (or steam load in lb/hr at stated temperature and pressure, rounded to the nearest lb/hr, if elected in the monitoring plan);

(4) Operating load range corresponding to total integrated gross load of 1–10, except for units using a common stack, which may use the number of unit load ranges up to 20, specified in the monitoring plan for the common stack;

(5) Total heat input (mmBtu, rounded to the nearest tenth); and

(6) For gas-fired units, the owner or operator may record total heat input (mmBtu, rounded to the nearest tenth) daily.

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

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

(i) Monitor-channel identification code as provided for in § 75.53;

(ii) Date and hour;

(iii) Average hourly SO_2 concentration (ppm, rounded to the nearest tenth),

(iv) Average hourly SO_2 concentration (ppm, rounded to the nearest tenth) adjusted for bias, if bias adjustment factor is required as provided for in § 75.24(d) of this part;

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

(vi) Method of determination for average hourly SO_2 concentration using Codes 1–12 in Table 3 of this section.

(2) For flow as measured and reported from the certified primary monitor, certified back-up or certified portable monitor or other approved method of emissions determination:

(i) Monitor-channel identification code as provided for in § 75.53;

(ii) Date and hour;

(iii) Average hourly volumetric flow rate (in scfh, rounded to the nearest thousand);

(iv) Average hourly volumetric flow rate (in scfh, rounded to the nearest thousand) adjusted for bias, if bias adjustment factor required as provided for in § 75.24(d) of this part;

(v) Average hourly moisture content of flue gases (volume fraction) where SO_2 concentration is measured on dry basis;

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

(vii) Method of determination for average hourly flow rate using Codes 1–12 in Table 3.

(3) For SO_2 mass emissions as measured and reported from the certified primary monitoring system, certified back-up or certified portable monitoring systems, or other approved method of emissions determination:

(i) Date and hour;

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

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

(iv) Unique three-digit code identifying emissions formula used to derive hourly SO_2 mass emissions from SO_2 concentration and flow data in paragraphs (c)(1) and (c)(2) of this section as provided for in § 75.53.

TABLE 3.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION

Code	Hourly emissions/flow measurement or estimation method
1	Certified primary emission/flow monitoring system.
2	Certified back-up or certified portable emission/flow monitoring system.
3	Approved alternative monitoring system.
4	Reference Method: SO_2: Method 6, 6A, 6B, or 6C. Flow: Method 2, 2A, 2C, or 2D. NO_x: Method 7, 7A, 7C, 7D, or 7E.
5	For units with add-on SO_2 and/or NO_x emission controls: SO_2 concentration or NO_x emission rate estimate from Agency preapproved parametric monitoring method.
6	Average of the hourly SO_2 concentrations, flow, or NO_x emission rate for the hour before and the hour following a missing data period.
7	Average hourly SO_2 concentration, flow rate, or NO_x emission rate using initial missing data procedures.
8	90th percentile hourly SO_2 concentration, flow rate, or NO_x emission rate.
9	95th percentile hourly SO_2 concentration, flow rate, or NO_x emission rate.
10	Maximum hourly SO_2 concentration, flow rate, or NO_x emission rate.
11	Average hourly flow rate or NO_x emission rate in corresponding load range.

TABLE 3.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION—Continued

Code	Hourly emissions/flow measurement or estimation method
12	Maximum potential concentration of SO_2 maximum potential flow rate, or NO_x emission rate corresponding to maximum potential concentration of NO_x and minimum O_2 or maximum CO_2 concentration, as determined using section 2.1 of Appendix A of this part.
13	Other data (specify method).

(d) *NO_x emission record provisions.* The owner or operator shall record hourly the information required by this paragraph for each affected unit, except for a gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the option protocol in Appendix E to this part for estimating NO_x emission rate. For each NO_x emission rate as measured and reported from the certified primary monitor, certified back-up or certified portable monitor, or other approved method of emissions determination:

(1) Monitor-channel identification code as provided for in § 75.53;

(2) Date and hour;

(3) Average hourly NO_x concentration (ppm, rounded to the nearest tenth);

(4) Average hourly diluent gas concentration (percent O_2 or percent CO_2, rounded to the nearest tenth);

(5) Average hourly NO_x emission rate (lb/mmBtu, rounded to nearest hundredth);

(6) Average hourly NO_x emission rate (lb/mmBtu, rounded to nearest hundredth) adjusted for bias, if bias adjustment factor is required as provided for in § 75.24(d) of this part;

(7) Percent monitoring system data availability, (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32 of this part;

(8) Method of determination for average hourly NO_x emission rate using Codes 1–12 in Table 3; and

(9) Unique three-digit code identifying emissions formula used to derive average hourly NO_x emission rate, as provided for in § 75.53.

(e) *CO_2 emission record provisions.* The owner or operator shall record or calculate CO_2 emissions for each affected unit using one of the following methods specified in this section:

(1) If the owner or operator chooses to use a CO_2 continuous emission monitoring system (or an O_2 continuous emission monitor and flow monitor as specified in Appendix F), then the owner or operator shall record hourly the following information for CO_2 mass emissions, as measured and reported from the certified primary monitor, certified back-up or certified portable monitor, or other approved method of emissions determination:

(i) Monitor-channel identification code as provided for in § 75.53;

(ii) Date and hour;

(iii) Average hourly CO_2 (or O_2) concentration (in percent, rounded to the nearest tenth);

(iv) Average hourly volumetric flow rate (scfh, rounded to the nearest scf);

(v) Average hourly CO_2 mass emissions (tons/hr, rounded to the nearest tenth);

(vi) Percent monitor data availability (recorded to the nearest tenth of a percent); calculated pursuant to § 75.32 of this part;

(vii) Method of determination for average hourly CO_2 mass emissions using Codes 1–12 in Table 3; and

(viii) Unique three-digit emissions formula used to derive average hourly CO_2 mass emissions, as provided for in § 75.53.

(2) As an alternative to § 75.50(e)(1), the owner or operator may use the procedures in § 75.13 and in Appendix G to this part, and shall record daily the following information for CO_2 mass emissions:

(i) Date;

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

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

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

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

(f) *Opacity record provisions.* The owner or operator shall record every six minutes (or other averaging period specified by the State or local air pollution control agency) the information required by this paragraph for each affected unit, except as provided for in § 75.14 (b), (c), and (d). The owner or operator shall also keep records of all incidents of opacity monitor downtime during unit operation, including reason(s) for the monitor outage(s) and any corrective action(s) taken for opacity, as measured and reported by the continuous opacity monitoring system:

(1) Monitor-channel identification code;

(2) Date, hour, and minute;

(3) Average opacity of emissions (in percent opacity);

(4) If the average opacity of emissions exceeds the applicable standard, then a code indicating such an exceedance has occurred; and

(5) Percent monitor data availability, recorded to the nearest tenth of a percent, calculated pursuant to § 75.32 of this part.

§ 75.51 General recordkeeping provisions for specific situations.

(a) *Specific SO_2 emission record provisions for units with qualifying Phase I technology.* In addition to the SO_2 emissions information required in § 75.50(c) of this part, from January 1, 1997, through December 31, 1999, the owner or operator shall record the applicable information in this paragraph for each affected unit on which SO_2 emission controls have been installed and operated for the purpose of meeting qualifying Phase I technology requirements pursuant to § 72.42 of this chapter and § 75.15.

(1) For units with post-combustion emission controls:

(i) Monitor-channel identification codes for each inlet and outlet SO_2-diluent continuous emission monitoring system;

(ii) Date and hour;

(iii) Average hourly inlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth);

(iv) Average hourly inlet SO_2 concentration (ppm, rounded to the nearest tenth) adjusted for bias, if bias adjustment factor required (see § 75.24(d) of this part);

(v) Average hourly outlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth);

(vi) Average hourly outlet SO_2 concentration (ppm, rounded to the nearest tenth) adjusted for bias, if bias adjustment factor required (see § 75.24(d) of this part);

(vii) Percent data availability for both inlet and outlet SO_2-diluent continuous emission monitoring systems (recorded to the nearest tenth of a percent), calculated pursuant to Equation 8 of § 75.32 (for the first 8,760 unit operating hours following initial certification) and Equation 9 of § 75.32, thereafter; and

(viii) Emissions formula used to derive average hourly SO_2 mass emissions for each affected unit or group of units using a common stack.

(2) For units with combustion and/or pre-combustion emission controls:

(i) Monitor-channel identification codes for each outlet SO_2 continuous emission monitoring system;

(ii) Date and hour;

(iii) Average hourly outlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth);

(iv) For units with combustion controls, average daily inlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth), determined by coal sampling and analysis procedures in Appendix F to this part; and

(v) For units with pre-combustion controls (i.e., fuel pretreatment), fuel analysis demonstrating the weight, sulfur content, and gross calorific value of the product and raw fuel lots.

(b) *Specific parametric data record provisions for calculating substitute emissions data for units with add-on emission controls.* In addition to the SO_2 and NO_x emission data to be recorded under § 75.50, the owner or operator of an affected unit with add-on emission controls where the owner or operator is using the approved site-specific parametric monitoring procedures for calculation of substitute data in accordance with § 75.34, then the owner or operator shall also record for each hour during each missing data period the applicable information in this paragraph (b):

(1) For units with add-on SO_2 emission controls, for each hour of missing SO_2 concentration or volumetric flow data:

(i) The information required in §75.50(b) of this part for SO_2 concentration and volumetric flow if either one of these monitors is still operating;

(ii) Date and hour;

(iii) Number of operating scrubber modules;

(iv) Feedrate of makeup slurry to each operating scrubber module (gal/min);

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

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

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

(vii) The slurry feed rate (gal/min) to the atomizer nozzle; and

(ix) Method of determination of SO_2 concentration and volumetric flow, using Codes 1–12 in Table 3 of § 75.50 of this part.

(2) For units with add-on NO_x emission controls, for each hour of missing NO_x emission rate data:

(i) Date and hour;

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

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

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

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

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

(c) *Specific SO_2 Emission Record Provisions for Gas-Fired or Oil-Fired Units Using Optional Protocol in Appendix D to This Part.* In lieu of recording the information in § 75.50(c) of this section, the owner or operator shall record the applicable information in this paragraph for each affected gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in Appendix D to this part for estimating SO_2 mass emissions.

(1) When the unit is combusting oil:

(i) Date and hour;

(ii) Average hourly flow rate of oil with the units in which oil flow is recorded, (gal/hr, lb/hr, or bbl/hr, rounded to the nearest tenth);

(iii) Sulfur content of daily oil sample, rounded to nearest tenth of a percent;

(iv) Method of oil sampling (flow proportional, continuous drip, or manual);

(v) Mass of oil combusted each hour (lb/hr, rounded to the nearest tenth); and

(vi) Average hourly SO_2 mass emissions (lb/hr, rounded to the nearest tenth).

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

(3) When the unit is combusting natural gas,

(i) Date and hour; and

(ii) Daily heat input from natural gas according to procedures in Appendix F to this part (mmBtu, rounded to the nearest tenth).

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

(A) Sulfur content of daily gas sample, (rounded to the nearest 0.1 grains/100 scf) and the volume of gas combusted per day, in 100 scf; or

(B) SO_2 emission rate from NADB (in lb/mmBtu).

(d) *Specific NO_x Emission Record Provisions for Gas-Fired Peaking Units or Oil-Fired Peaking Units Using Optional Protocol in Appendix E of This Part.* In lieu of recording the information in paragraph § 75.50(d), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in Appendix E to this part for estimating NO_x emission rate.

(1) When the unit is combusting oil,

(i) Date and hour;

(ii) Average daily fuel flow of oil with the units in which oil flow is recorded (gal/day or bbl/day);

(iii) NO_x emission rate F-factor for oil combusted according to procedure in Appendix E to this part; and

(iv) Average daily NO_x emission rate (lb/mmBtu, rounded to nearest tenth).

(2) When the unit is combusting natural gas,

(i) Date and hour;

(ii) Average daily fuel flow of natural gas (million cubic ft);

(iii) NO_x emission rate F-factor for gas combusted according to procedure in Appendix E to this part; and

(iv) Average daily NO_x emission rate (lb/mmBtu, rounded to nearest tenth).

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

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

(1) For each SO_2 or NO_x pollutant concentration monitor, flow monitor, CO_2 monitor, or diluent gas monitor, the owner or operator shall record the following for all daily and 7-day calibration error tests, including any follow-up tests after corrective action:

(i) Monitor channel identification code;

(ii) Instrument span;

(iii) Date and hour;

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

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

(vi) Percent calibration error (rounded to nearest tenth of a percent);

(vii) Number of out-of-control hours, if any, following test; and

(viii) Description of any adjustments, corrective actions, or maintenance following test.

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

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

(ii) Number of out-of-control hours, if any, following test; and

(iii) Description of any adjustments, corrective actions, or maintenance following test.

(3) For each SO_2 or NO_x pollutant concentration monitor, CO_2 monitor, or diluent gas monitor, the owner or operator shall record the following for the initial and all subsequent linearity check(s), including any follow-up tests after corrective action:

(i) Monitor channel identification code;

(ii) Instrument span;

(iii) Date and hour;

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

(v) Observed value (average monitor response at each reference gas concentration, in ppm or other appropriate units);

(vi) Percent error at each of three reference gas concentrations (rounded to nearest tenth of a percent);

(vii) Number of out-of-control hours, if any, following test; and

(viii) Description of any adjustments, corrective action, or maintenance following test.

(4) For each flow monitor, where applicable, the owner or operator shall record the following for all quarterly leak checks, including any follow-up tests after corrective action:

(i) Code indicating whether monitor passes or fails the quarterly leak check;

(ii) Number of out-of-control hours, if any, following test; and

(iii) Description of any adjustments, corrective actions, or maintenance following test.

(5) For each SO_2 pollutant concentration monitor, flow monitor, CO_2 pollutant concentration monitor; NO_x continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, and approved alternative monitoring system, the owner or operator shall record the following information for the initial and all subsequent relative accuracy tests and test audits:

(i) Date and hour;

(ii) Reference method(s) used;

(iii) Individual test run data from the relative accuracy test audit for the SO_2 concentration monitor, flow monitor, CO_2 pollutant concentration monitor, NO_x continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, or approved alternative monitoring systems, including:

(A) Date, hour, and minute of beginning of test run,

(B) Date, hour, and minute of end of test run,

(C) Monitor-channel identification code,

(D) Run number,

(E) Run data for monitor;

(F) Run data for reference method; and

(G) Flag value (0 or 1) indicating whether run has been used in calculating relative accuracy and bias values.

(iv) Calculations and tabulated results, as follows:

(A) Arithmetic mean of the monitoring system measurement values, reference method values, and of their differences, as specified in Equation A–7 in appendix A to this part.

(B) Standard deviation, as specified in Equation A–8 in appendix A to this part.

(C) Confidence coefficient, as specified in Equation A–9 in appendix A to this part.

(D) Relative accuracy test results, as specified in Equation A–10 in appendix A to this part. (For the 3-level flow monitor test only, relative accuracy test results should be recorded at each of three gas velocities. Each of these three gas velocities shall be expressed as a total integrated gross unit load, rounded to the nearest MWe.)

(E) Bias test results as specified in section 7.6.4 in appendix A to this part.

(F) Bias adjustment factor from Equations A–11 and A–12 in appendix A to this part for any monitoring system or component that failed the bias test and 1.0 for any monitoring system or component that passed the bias test. (For flow monitors only, bias adjustment factors should be recorded at each of three gas velocities).

(G) Number of out-of-control hours, if any, following test.

(H) Description of any adjustment, corrective action, or maintenance following test.

(6) F-factor value(s) used to convert NO_x pollutant concentration and diluent gas (O_2 or CO_2) concentration measurements into NO_x emission rates (in lb/mmBtu), heat input or CO_2 emissions.

(7) Results of all trial runs and certification tests and quality assurance activities and measurements (including all reference method field test sheets, charts, records of combined system responses, laboratory analyses, and example calculations) necessary to substantiate compliance with all relevant appendices in this part.

§ 75.53 Monitoring plan.

(a) General provisions. The owner or operator of an affected unit shall prepare and maintain a monitoring plan. Except as provided in paragraphs (c) and (d) of this section, a monitoring plan shall contain sufficient information on the continuous emission or opacity monitoring systems and the use of data derived from these systems to demonstrate that all unit SO_2 emissions, NO_x emissions, CO_2 emissions when monitored continuously, and opacity are monitored and reported by continuous emission or opacity monitoring systems.

(b) Whenever the owner or operator makes a replacement, modification, or change, either in the certified continuous emission monitoring system or continuous opacity monitoring system, including the automated data acquisition and handling system or in the flue gas handling system, that requires recertification, then the owner or operator shall update the monitoring plan.

(c) Contents of the monitoring plan. Each monitoring plan shall contain the following:

(1) Precertification information, including the identification of the test strategy and protocol for the relative accuracy test audit and other relevant test information; and

(2) Unit table. A table identifying all units, using ORISPL numbers developed by the Department of Energy and used in the National Allowance Database, for all affected units involved in the monitoring plan with the following information for each unit:

(i) Short name;

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

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

(iv) Type of fuel(s) fired, by boiler, and if more than one fuel, the fuel classification of the boiler;

(v) Type(s) of emission controls for SO_2, NO_x, and particulates installed or to be installed, including specifications of whether such controls are pre-combustion, post-combustion, or integral to the combustion process; and

(vi) Identification of all units using a common stack.

(3) Description of monitor site location. Description of site locations for each monitoring component in the continuous emission or opacity monitoring systems, including schematic diagrams and engineering drawings specified in paragraphs (c)(7) and (c)(8) of this section, and any other documentation that demonstrate each monitor location meets the appropriate siting criteria.

(4) Monitoring component table. Identification and description of each monitoring component (including each monitor and its identifiable components such as analyzer and/or probe) in the

continuous emission monitoring systems (i.e., SO_2 pollutant concentration monitor, flow monitor, moisture monitor; NO_x pollutant concentration monitor and diluent gas monitor) and the continuous opacity monitoring system, including:

(i) Manufacturer model number and serial number;

(ii) Monitor-channel identification code assigned by the utility to each monitor or identifiable monitoring component (such as the analyzer and/or probe). The code shall use a six-digit format, unique to each monitoring component, where the first three digits indicate the number of the component and the second three digits indicate the "channel" the particular parameter that the monitor measures;

(iii) Actual or projected installation date (month and year); and

(iv) A brief description of the component type or method of operation, such as in situ pollutant concentration monitor or thermal flow monitor.

(v) A brief description of the flow monitor that is sufficiently detailed to allow a determination of whether the applicable interference check design specification meets the requirements specified in Appendix A of this part.

(vi) A designation of the component as a primary or backup component, as provided for in § 75.10(g).

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

(i) For hardware components, the manufacturer, model number, and actual or projected installation date;

(ii) For software components, identification of the provider, whether the software is a custom, turn-key, or commercially available product, and a brief description of features;

(iii) A data flow diagram denoting the complete information handling path from output signals of continuous emission monitoring system components to final reports;

(iv) A copy of the test results verifying the accuracy of the automated data acquisition and handling system (once such results are available).

(6) Emissions formula table. A table giving explicit formulas for each reported unit emission parameter, using monitor-channel identification codes to link continuous emission monitoring system observations with reported concentrations, mass emissions, or emission rates, according to the conversions listed in appendix F to this part. The formulas must contain all constants and factors required to derive mass emissions or emission rates from monitor-channel code observations, and each emissions formula is identified with a unique three digit code.

(7) Schematic stack diagrams. A schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitors, and stacks corresponding to the identification numbers provided in paragraphs (c)(2), (c)(4), (c)(5), and (c)(6) of this section. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack.

(8) Stack and duct engineering diagrams. Stack and duct engineering diagrams showing the dimensions, and also showing location of fans, turning vanes, air preheaters, monitors, probes, reference method sampling ports and other equipment which affects the monitoring system location, performance or quality control checks.

(9) Inside crosssectional area (ft^2) at flue exit.

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

(i) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in Appendix D of this part for estimating SO_2 mass emissions or Appendix E of this part for estimating NO_x emission rate (using a fuel flow meter), the designated representative shall include in the monitoring plan a description of the fuel flowmeter and data demonstrating its flow meter accuracy.

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

(A) The NO_x emission rate F-factor for each fuel combusted by the unit; and

(B) All baseline and periodic NO_x emissions test data and results used to determine the NO_x emission rate F-factor for each fuel.

Subpart G—Reporting Requirements

§ 75.60 General provisions.

(a) The designated representative for any affected unit subject to the requirements of this part shall comply with all reporting requirements in this section and with the signatory requirements of § 72.21 of this chapter for all submissions.

(b) Submissions. The designated representative shall submit all reports and petitions (except as provided in § 75.61) as follows:

(1) All certification or recertification notifications, certification or recertification applications, monitoring plans, petitions for alternative monitoring systems, notifications, electronic quarterly reports, and other communications required by this subpart shall be submitted to the Administrator.

(2) Copies of certification or recertification notifications, certification or recertification applications and monitoring plans shall be submitted to the appropriate Regional Office of the U.S. Environmental Protection Agency and appropriate State or local air pollution control agency.

§ 75.61 Notification of certification and recertification test dates.

(a) *Submission.* The owner or operator or designated representative for an affected unit shall submit written notification of certification tests, recertification tests, and revised test dates for continuous emission monitoring systems, as specified in § 75.20 of this part. Certification test notifications shall be submitted not later than 45 days prior to the first day of certification or recertification testing, except as provided in § 75.20(a)(1)(ii) of this part. Recertification test notifications shall be provided as soon as practicable but not later than the second business day following the identified need for recertification.

(1) The owner or operator or designated representative shall notify the Administrator, the appropriate EPA Regional Office, and the applicable State air pollution control agency at least 7 business days in advance of any proposed adjustments to the certification testing dates.

(2) The owner or operator or designated representative shall submit notification of certification tests and recertification tests for continuous opacity monitoring systems, as specified in § 75.20(c)(6) of this part to the State or local air pollution control agency.

(3) If notification substantially similar to that required in this section is required by any other State or local agency, the owner or operator or designated representative may send the Administrator a copy of that notification to satisfy this requirement, provided the ORISPL unit identification number(s) is denoted.

(b) [Reserved]

§ 75.62 Monitoring plan.

(a) *Submission.* The designated representative for an affected unit shall submit the monitoring plan to the

Administrator no later than 45 days prior to the certification test.

(b) *Contents.* Monitoring plans shall contain the information specified in § 75.53 of this part.

§ 75.63 Certification or recertification application.

(a) *Submission.* The designated representative for an affected unit shall submit the request to the Administrator within 30 days after completing the certification test.

(b) *Contents.* Each application for certification or recertification shall contain the following information:

(1) A copy of the monitoring plan (or any modifications to the monitoring plan) for the unit or units if not previously submitted.

(2) The results of the test(s) required by § 75.20 of this part, including the type of test conducted, testing date, and including the results of any failed tests that had been repeated pursuant to the requirements in § 75.20.

(3) Results of the tests for verification of the accuracy of emissions and volumetric flow calculations performed by the automated data acquisition and handling system, including a summary of equations used to convert component data to units of the standard and to calculate substitute data for missing data periods, including sample calculations.

(c) *Electronic format.* Each certification application shall be submitted in a format to be specified by the Administrator.

§ 75.64 Quarterly reports.

(a) *Submission.* The designated representative for an affected unit shall electronically report the data and information in paragraphs (a), (b), and (c) of this section to the Administrator quarterly, beginning with the data from the later of: The last (partial) calendar quarter of 1993 (where the calendar quarter data begins at November 15, 1993); or the calendar quarter corresponding to the relevant deadline for certification in § 75.4 of this part. For any provisionally-certified monitoring system, some or all of the quarterly data may be invalidated, if the Administrator subsequently issues a notice of disapproval within 120 days of receipt of the complete certification application for the monitoring system. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter and shall include for each affected unit (or group of units using a common stack):

(1) The information and hourly data required in §§ 75.50–75.52 of this part, excluding the descriptions of adjustments, corrective action, and maintenance and excluding any information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan, etc.).

(2) Tons (rounded to the nearest tenth) of SO_2 emitted during the quarter and cumulative SO_2 emissions for calendar year.

(3) Average NO_x emission rate (lb/mmBtu, rounded to the nearest hundredth) during the quarter and cumulative NO_x emission rate for calendar year.

(4) Tons of CO_2 emitted during quarter and cumulative CO_2 emissions for calendar year.

(5) Total heat input (mmBtu) and integrated gross unit load (MWge) for quarter and cumulative heat input and integrated gross unit load for calendar year.

(6) If the affected unit is using a qualifying Phase I technology, then the quarterly report shall include the information required in paragraph (e) of this section.

(b) The designated representative shall affirm that the monitor-channel identification codes and formulas in the quarterly electronic reports, submitted to the Administrator pursuant to § 75.53 of this part, represent current operating conditions.

(c) *Compliance certification.* The designated representative shall submit a certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this part including the quality control and quality assurance procedures and specifications of this part and its appendices, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method. In the event of any missing data periods, the certification must describe the measures taken to cure the causes for the missing data periods.

(d) *Electronic format.* Each quarterly report shall be submitted in a format to be specified by the Administrator.

(e) *Phase I qualifying technology reports.* In addition to reporting the information in paragraphs (a), (b), and (c) of this section, the designated representative for an affected unit on which SO_2 emission controls have been installed and operated for the purpose of meeting qualifying Phase I technology requirements pursuant to § 72.42 of this chapter shall also submit reports documenting the measured percent SO_2 emissions removal to the Administrator on a quarterly basis, beginning the first quarter of 1997 and continuing through the fourth quarter of 1999. Each report shall include the following information:

(1) For the first report only, a copy of the start up acceptance test result upon which the designated representative accepted the systems potential to meet the ninety percent reduction requirement.

(2) All measurements and calculations necessary to substantiate that the qualifying technology achieves the overall percent reduction in SO_2 emissions.

§ 75.65 Opacity reports.

The designated representative shall report excess emissions of opacity to the applicable State or local air pollution control agency, in a format specified by the applicable State or local air pollution control agency.

§ 75.66 Petitions to the Administrator.

(a) *Alternative flow monitor location demonstration reports.* In cases where no location exists for installation of a flow monitor in either the stack or the ducts serving an affected unit that satisfies the minimum physical siting criteria in Appendix A to this part or where installation of a flow monitor in either the stack or duct is demonstrated to the satisfaction of the Administrator to be technically infeasible, the designated representative for the affected unit may petition the Administrator for an alternative monitoring location or alternative method for monitoring volumetric flow. The demonstration report shall, at a minimum, contain the following information.

(1) Identification of the affected unit(s).

(2) Description of why the minimum siting criteria cannot be met within the existing ductwork or stack(s). This description shall include diagrams of the existing ductwork or stack, as well as documentation of any attempts to locate a flow monitor.

(3) Description of proposed alternative monitoring location or alternative method for monitoring flow.

(b) *Alternative ASTM method demonstration reports.* The designated representative for an affected unit may apply to the Administrator for an alternative to any ASTM method prescribed in this part. The designated representative shall include the following information in an application:

(1) A description of why the prescribed ASTM method is not being used;

(2) A description and diagram(s) of all equipment and procedures in the proposed alternative method;

(3) Data demonstrating that the proposed alternative method produces data of equal or greater precision and accuracy to that from the prescribed ASTM method(s).

(c) *Alternative monitoring system petitions.* The designated representative for an affected unit may submit a petition to the Administrator for approval and certification of an alternative monitoring system or component according to the procedure in subpart E of this part. Each petition shall contain the information and data specified in subpart E, including the information specified in § 75.48, in a format to be specified by the Administrator.

(d) *Parametric monitoring procedure petitions.* The designated representative for an affected unit may submit a petition to the Administrator, where each petition shall contain the information specified in § 75.51(b) for use of a parametric monitoring method.

(e) *Missing Data Petitions for units with add-on emission controls.* The designated representative for an affected unit may submit a petition to the Administrator, which the Administrator will automatically approve if the petition adequately demonstrates that all the requirements in § 75.34 are satisfied, where each petition shall contain the information listed below for the time period (or data gap) during which the affected unit experienced the monitor outage that would result in the substitution of an uncontrolled maximum value under the standard missing data procedures contained in subpart D of this part:

(1) Data demonstrating that the affected unit's monitor data availability for the time period under petition was less than 90%,

(2) Data demonstrating that the add-on emission controls were operating properly during time period under petition, and

(3) A list of the average hourly values for the previous 720 quality-assured monitor operating hours, highlighting both the maximum recorded value and the value corresponding to the maximum controlled emission rate.

(f) *Any other petitions to the Administrator.* The designated representative for an affected unit shall include sufficient information for the evaluation of any other petition submitted to the Administrator under this part.

§ 75.67 Retired units petitions.

For units that will be permanently retired prior to January 1, 1995, an exemption from the requirements of this part, including the requirement to install and certify a continuous emissions monitoring system, may be obtained from the Administrator if the designated representative submits a complete petition, as required in § 72.8, to the Administrator prior to the deadline in § 75.4 by which the continuous emission or opacity monitoring systems must complete the required certification tests.

Appendix A to Part 75—Specifications and Test Procedures

1. Installation and Measurement Location

1.1 Pollutant Concentration and CO_2 or O_2 Monitors

Following the procedures in section 3.1 of Performance Specification 2 in Appendix B to part 60 of this chapter, install the pollutant concentration monitor or monitoring system at a location where the pollutant concentration and emission rate measurements are directly representative of the total emissions from the affected unit. Select a representative measurement point or path for the monitor probe(s) (or for the path from the transmitter to the receiver) such that the SO_2 pollutant concentration monitor or NO_x continuous emission monitoring system (NO_x pollutant concentration monitor and diluent gas monitor) will pass the relative accuracy test (see section 6).

It is recommended that monitor measurements be made at locations where the exhaust gas temperature is above the dew-point temperature. If the cause of failure to meet the relative accuracy tests is determined to be the measurement location, relocate the monitor probe(s).

1.1.1 Point Pollutant Concentration and CO_2 or O_2 Monitors

Locate the measurement point (1) within the centroidal area of the stack or duct cross section, or (2) no less than 1.0 meter from the stack or duct wall.

1.1.2 Path Pollutant Concentration and CO_2 or O_2 Gas Monitors

Locate the measurement path (1) totally within the inner area bounded by a line 1.0 meter from the stack or duct will, or (2) such that at least 70.0 percent of the path is within the inner 50.0 percent of the stack or duct cross-sectional area, or (3) such that the path is centrally located within any part of the centroidal area.

1.2 Flow Monitors

Install the flow monitor in a location that provides representative volumetric flow over all operating conditions. Such a location is one that provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. Where the moisture content of the flue gas affects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of Appendix A to part 60 of this chapter to establish a proper location for the flow monitor. EPA recommends (but does not require) performing a flow profile study following the procedures in 40 CFR part 60, Appendix A, Text Method, 1, section 2.5 for each of the three operating or load levels indicated in section 6.5.2 of this appendix to determine the acceptability of the potential flow monitor location and to determine the number and location of flow sampling points required to obtain a representative flow value. The procedure in 40 CFR part 60, Appendix A, Test Method 1, section 2.5 may be used even if the flow measurement location is greater than or equal to 2 equivalent stack or duct diameters downstream or greater than or equal to ½ duct diameter upstream from a flow disturbance. If a flow profile study shows that cyclonic (or swirling) or stratified flow conditions exist at the potential flow monitor location that are likely to prevent the monitor from meeting the performance specifications of this part, then EPA recommends either (1) selecting another location where there is no cyclonic (or swirling) or stratified flow condition, or (2) eliminating the cyclonic (or swirling) or stratified flow condition by straightening the flow, e.g., by installing straightening vanes. EPA also recommends selecting flow monitor locations to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

1.2.1 Acceptability of Monitor Location

The installation of a flow monitor is acceptable if (1) the location satisfies the minimum siting criteria of Method 1 in Appendix A to part 60 of this chapter (i.e., the location is greater than or equal to eight stack or duct diameters downstream and two diameters upstream from a flow disturbance; or, if necessary, two stack or duct diameters downstream and one-half stack or duct diameter upstream from a flow disturbance), (2) the results of a flow profile study, if performed, are acceptable (i.e., there are no cyclonic (or swirling) or stratified flow conditions), and (3) the flow monitor satisfies the performance specifications of this part. If the flow monitor is installed in a location that does not satisfy these physical criteria, but nevertheless the monitor achieves the performance specifications of this part, then the Administrator may certify the location as acceptable.

1.2.2 Alternative Monitoring Location

Whenever the flow monitor is installed in a location that is grater than or equal to two stack or duct diameters downstream and greater or equal to one-half diameter upstream from a flow disturbance, and/or in a location that is acceptable based on a flow profile study, but nevertheless the monitor does not achieve the performance specifications of this part, perform another flow profile study (the procedures described in section 2.5 of Method 1 in Appendix A to part 60 of this chapter may be used) to select an alternative flow monitoring installation site.

Whenever the owner or operator successfully demonstrates that modifications

to the exhaust duct or stack (such as installation of straightening vanes, modifications of ductwork, and the like) are necessary for the flow monitor to meet the performance specifications, the Administrator may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

Where no location exists that satisfies the physical siting criteria in section 1.2.1, where the results of flow profile studies performed at two or more alternative flow monitor locations are unacceptable, and where installation of a flow monitor in either the stack or the ducts is demonstrated to be technically infeasible, the owner or operator may petition the Administrator for an alternative method for monitoring flow.

2. Equipment Specifications

2.1 Instrument Span

In implementing sections 2.1.1 through 2.1.4 of this appendix, to the extent practicable, measure at a range such that the majority of readings obtained during normal operation are between 25 and 75 percent of full-scale range of the instrument.

2.1.1 SO_2 Pollutant Concentration Monitors

Determine, as indicated below, a span value for pollutant concentration monitors so that it includes all expected concentrations.

2.1.1.1 Maximum Potential Concentration

The monitor must be capable of accurately measuring up to 125 percent of the maximum potential concentration as calculated using Equation A–1a or A–1b. Calculate the maximum potential concentration by using Equation A–1a or A–1b and the maximum percent sulfur and minimum gross calorific value (GCV) for the highest sulfur fuel to be burned. Base the maximum percent sulfur and minimum GCV on the results of all available fuel sampling and analysis data from the previous 12 months (where such data exists) using ASTM Methods ASTM D3177–89, "Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke," ASTM D4239–85, "Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods," ASTM D4294–90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy," ASTM D1552–90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D129–91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," or ASTM D2622–92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry" for sulfur content of solid or liquid fuels, or ASTM D3176–89, "Standard Practice for Ultimate Analysis of Coal and Coke", ASTM D240–87 (Reapproved 1991), "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter" or ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiebatic Bomb Calorimeter" for GCV (incorporated by reference under § 75.6). Then, multiply the maximum potential concentration by 125 percent, and round up the resultant concentration to the nearest multiple of 100 ppm to determine the span value. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater than or equal to the span value. The span value will be used to determine the concentrations of the calibration gases. The selected monitor range based on 125 percent of the maximum potential concentration will henceforth be referred to as the "high-scale" of the SO_2 pollutant concentration monitor.

$$MPC = 11.32 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{20.9-\%O_{2w}}{20.9}\right) \qquad \text{(Eq. A-1a)}$$

or

$$MPC = 66.93 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{\%CO_{2w}}{100}\right) \qquad \text{(Eq. A-1b)}$$

where,

MPC=Maximum potential concentration (ppm, wet basis). To convert to dry basis, divide the MPC by 0.9.)

%S=Maximum sulfur content of fuel to be fired, wet basis, weight percent, as determined by ASTM D3177–89, ASTM D4239–85, ASTM D4294–90, ASTM D1552–90, ASTM D129–91, or ASTM D2622–92 for solid or liquid fuels (incorporated by reference under § 75.6).

GCV=Minimum gross calorific value of the fuel lot consistent with the sulfur analysis (Btu/lb), as determined using ASTM D3176–89, ASTM D240–87 (Reapproved 1991), or ASTM D2015–91 (incorporated by reference under § 75.6).

$\%O_{2w}$=Minimum oxygen concentration, percent wet basis, under normal operating conditions.

$\%CO_{2w}$=Maximum carbon dioxide concentration, percent wet basis, under normal operating conditions.

11.32×10^6=Oxygen-based conversion factor in (Btu/lb)(ppm)/%.

66.93×10^6=Carbon dioxide-based conversion factor in (Btu/lb)(ppm)/%

Note: All percent values to be inserted in the equations of this section are to be expressed as a percentage, not a fractional value, e.g., 3, not .03.

2.1.1.2 Maximum Expected Concentration

If the majority of SO_2 concentration values are predicted to be less than 25 percent of the full-scale range of the instrument based upon 125 percent of the maximum potential concentration, (e.g., at the outlet of an SO_2 emission control) use an additional (lower) monitor range. (For this second range, use Equation A–2 to calculate the maximum expected concentration (MEC). Multiply the maximum expected concentration by 125 percent, and round up the resultant concentration to the nearest multiple of 10 ppm to determine the span value. For this lower range, select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater than or equal to the lower range span value. Units using a lower range must also be capable of accurately measuring the anticipated actual concentrations up to and including 125 percent of the maximum potential concentration. The span value of this additional range will also be used to determine concentrations of the calibration gases for this additional range. The selected monitor range based on 125 percent of the maximum expected concentration will henceforth be referred to as the "low-scale" of SO_2 pollutant concentration monitors.

$$MEC = MPC[(100-RE)/100] \qquad \text{(Eq. A-2)}$$

where,

MEC=Maximum expected concentration (ppm).

MPC=Maximum potential concentration (ppm), as determined by Eq. A–1a or A–1b.

RE=Design removal efficiency of control equipment (%).

2.1.1.3 Auto-ranging Monitors

For monitors that can continuously and automatically adjust their range of measurement, the monitor must be capable at any time of accurately measuring up to 125

percent of the maximum potential concentration, as calculated using Equation A–1a or A–1b. Define the span value(s) for an auto-ranging monitor as 125 percent of the maximum potential concentration and 125 percent of the maximum expected concentration if a second span is determined to be necessary under section 2.1.1.2 of this appendix. Determine concentrations of the calibration gases based upon the span value(s).

2.1.1.4 Adjustment of Span

Wherever the SO_2 concentration exceeds the maximum potential concentration and the monitor can measure and record these values accurately, they may be reported for use in the Acid Rain Program. If the concentration exceeds the monitor's ability to measure and record values accurately, adjust the full-scale range setting to prevent future exceedances. Whenever the fuel supply or emission controls change such that the maximum expected or potential concentration may change significantly, adjust the range setting to assure the continued proper operation of the monitoring system. Whenever the range setting is adjusted, multiply the new range setting by 80 percent, and round up the resultant concentration to the nearest multiple of 100 ppm (or 10 ppm, if appropriate) to determine the new span value. Record the new span value and report the new span value as part of the results of the daily calibration error test required by Appendix B of this part. Whenever the span value is adjusted, use calibration gas concentrations based on the new span value.

2.1.2 NO_x Pollutant Concentration Monitors

Determine, as indicated below, a span value for the NO_x pollutant concentration monitor so that all expected NO_x concentrations can be determined and recorded accurately including both the maximum expected and potential concentration.

2.1.2.1 Maximum Potential Concentration

Use 800 ppm for coal-fired and 400 ppm for oil- or gas-fired units as the maximum potential concentration of NO_x. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater than or equal to the span value of 125 percent of the maximum potential concentration. If the maximum potential concentration is expected to be higher than the values stated above due to unit type (e.g. cyclone burner), or if it is determined through testing of the unit that the maximum potential concentration exceeds the above values, do one of the following: (1) Use a maximum potential concentration of 1600 ppm for coal-fired or 480 ppm for oil- or gas-fired units and set a span value of 125 percent of the maximum potential concentration (yielding a span value of 2000 ppm or 600 ppm); or (2) determine the maximum potential concentration based upon testing results and set the span value equal to 125 percent of the maximum potential concentration, rounding up to the nearest multiple of 100 ppm. The concentration of calibration gases is calculated as a percentage of the span value. The selected monitor range based on 125 percent of the maximum potential concentration will henceforth be referred to as the "high-scale" of the NO_x pollutant concentration monitor.

2.1.2.2 Maximum Expected Concentration

If the majority of NO_x concentrations are expected to be less than 25 percent of the full-scale range of the instrument based upon 125 percent of the maximum potential concentration, (e.g., at the outlet of a NO_x add-on emission control) use an additional "low-scale" monitor range. Use 320 ppm for coal-fired and 160 ppm for oil- or gas-fired units as the maximum expected concentration of NO_x. Calculate the span value of this second range by multiplying the maximum expected concentration by 125 percent (yielding 400 ppm or 200 ppm as the span value). If the efficiency of removal of an emission control is such that the maximum expected concentration, as determined by Equation A–2, differs by more than ±50 ppm from the values above, instead use the maximum expected concentration determined by Equation A–2. Calculate the span by multiplying the maximum expected concentration by 125 percent and round up the resultant concentration to the nearest multiple of 10 ppm. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater or equal to the lower range span value. The selected monitor range based on 125 percent of the maximum expected concentration will henceforth be referred to as the "low-scale" of NO_x pollutant concentration monitors. The span value of this additional range will also be used to determine the concentrations of the calibration gases for this additional range. NO_x pollutant concentration monitors on affected units with NO_x emission controls, or on other units with dual-span monitors, must also be capable of accurately measuring up to 125 percent of the maximum potential concentration. For dual-span NO_x pollutant concentration monitors, determine the concentration of calibration gases based on both span values.

2.1.2.3 Auto-ranging monitors

For monitors that can continuously and automatically adjust their range of measurement, the monitor must be capable at any time of accurately measuring up to 125 percent of the maximum potential concentration as defined in section 2.1.2.1 of this appendix. Define the span value(s) for an auto-ranging monitor as 125 percent of the maximum potential concentration and 125 percent of the maximum expected concentration if a second span is determined to be necessary under section 2.1.2.2 of this appendix. Determine concentrations of the calibration gases based upon the span value(s).

2.1.2.4 Adjustment of Span

Wherever the actual NO_x concentration exceeds the monitor's ability to measure and record values accurately, adjust the full-scale range setting to prevent future exceedances. Whenever the fuel supply, emission controls, or other process parameters change such that the maximum expected concentration or the maximum potential concentration may change significantly, adjust the NO_x pollutant concentration monitor range to assure the continued accuracy of the monitoring system. Whenever the range setting is adjusted, multiply the new range setting by 80 percent, and round up the resultant concentration to the nearest multiple of 100 ppm (or 10 ppm, if appropriate) to determine the new span value. Record the new span value, and report the new span value as part of the results of the daily calibration error test required by Appendix B of this part. Whenever the span value is adjusted, use calibration gas concentrations based on the new span value.

2.1.3 CO_2 and O_2 Monitors

Define the "high scale" span value as 20 percent O_2 or 20 percent CO_2. All O_2 and CO_2 analyzers must have "high-scale" measurement capability. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix, and to be greater than or equal to the span value. If the O_2 or CO_2 concentrations are expected to be consistently low, a "low scale" measurement range may be used for increased accuracy, provided that it is consistent with section 2.1 of this appendix. Multiply the "low-scale" range setting by 80 percent to determine the lower range span value, and determine the concentration of calibration gases based on both span values.

2.1.4 Flow Monitors

Select the full-scale range of the flow monitor so that it is consistent with section 2.1 of this appendix, and can accurately measure all potential volumetric flow rates at the flow monitor installation site. For this purpose, determine the span value of the flow monitor by multiplying the maximum potential velocity from previous tests or calculations by 125 percent, or using the following procedure. Calculate the maximum potential velocity (MPV) using Equation A–3a or A–3b. Multiply the MPV by 125 percent, and round up to the nearest multiple of 100 fpm to calculate the span value.

$$MPV = \left(\frac{F_d H_f}{A}\right)\left(\frac{20.9}{20.9 - \%O_{2d}}\right)\left[\frac{100}{(100 - \%H_2O)}\right]$$

or

$$MPV = \left(\frac{F_c H_f}{A}\right)\left(\frac{100}{\%CO_{2d}}\right)\left[\frac{100}{(100-\%H_2O)}\right] \text{(Eq. A-3b)}$$

where:

MPV=maximum potential velocity (fpm, standard wet basis),

F_d=dry-basis F factor (dscf/mmBtu) from Table 1, Appendix F of this part,

F_c=carbon-based F factor (scfCO_2/mmBtu) from Table 1, Appendix F of this part,

H_f=maximum heat input (mmBtu/minute) for all units, combined, exhausting to the stack or duct where the flow monitor is located,

A=inside cross sectional area (ft^2) of the flue at the flow monitor location,

%O_{2d}=maximum oxygen concentration, percent dry basis, under normal operating conditions,

%CO_{2d}=minimum carbon dioxide concentration, percent dry basis, under normal operating conditions,

%H_2O=maximum percent flue gas moisture content under normal operating conditions.

If the volumetric flow rate exceeds the flow monitor's ability to accurately measure and record values, adjust the full-scale range setting to prevent future exceedances. If the fuel supply, process parameters or other conditions change such that the maximum potential velocity may change significantly, adjust the range to assure the continued accuracy of the flow monitor. Whenever the range setting is adjusted, multiply the new range setting by 80 percent, and round up the resultant value to the nearest multiple of 100 fmp to determine the new span value. Record the new span value and report the new span value and reference values as parts of the results of the calibration error test required by Appendix B of this part. Whenever the span value is adjusted, use reference values for the calibration error test based on the new span value.

2.2 Design for Quality Control Testing

2.2.1 Pollutant Concentration and CO_2 or O_2 Monitors

Design and equip each pollutant concentration and CO_2 or O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (e.g., sample lines, filters, scrubbers, conditioners, and as much of the probe as practicable) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all active electronic and optical components (e.g. transmitter, receiver, analyzer).

Design and equip each pollutant concentration or CO_2 or O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero- and high-level concentrations specified in Section 5.2 of this Appendix.

2.2.2 Flow Monitors

Design all flow monitors to meet the applicable performance specifications.

2.2.2.1 Calibration Error Test

Design and equip each flow monitor to allow for a daily calibration error test consisting of at least two reference values: (1) Zero to 20 percent of span or an equivalent reference value (e.g., pressure pulse or electronic signal) and (2) 50 to 70 percent of span. Flow monitor response, both before and after any adjustment, must be capable of being recorded by the data acquisition and handling system. Design each flow monitor to allow a daily calibration error test of (1) the entire flow monitoring system, from and including the probe tip (or equivalent) through and including the data acquisition and handling system, or (2) the flow monitoring system from and including the transducer through and including the data acquisition and handling system.

2.2.2.2 Interference Check

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent velocity sensing interference, and (2) a means for detecting leaks in the system on at least a quarterly basis (manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (e.g., backpurging system) to prevent velocity sensing interference.

3. Performance Specifications

3.1 Calibration Error

The initial calibration error performance specification of SO_2 and NO_x pollutant concentration monitors shall not deviate from the reference value of the calibration gas by more than 2.5 percent based upon the span of the instrument, as calculated using Eq. A–5 of this appendix. Alternatively, where the span value is less than 200 ppm, calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value, $|R-A|$ in Equation A–5 of this appendix, is less than or equal to 5 ppm. The calibration error of CO_2 or O_2 monitors shall not deviate from the reference value of the zero- or high-level calibration gas by more than 0.5 percent O_2 or CO_2 as calculated using the term $|R-A|$ in the numerator of Eq. A–5 of this appendix. The calibration error of flow monitors shall not exceed 3.0 percent based upon the span of the instrument as calculated using Eq. A–6 of this appendix.

3.2 Linearity Check

For SO_2 and NO_x pollutant concentration monitors, the error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent (as calculated using Equation A–4 of this appendix). Linearity check results are also acceptable if the absolute value of the difference between the average of the monitor response values and the average of the reference values, $|R-A|$ in Equation A–4 of this appendix, is less than or equal to 5 ppm. For CO_2 or O_2 monitors:

(1) The error in linearity for each calibration gas concentration (low-, mid-, and high-levels) shall not exceed or deviate from the reference value by more than 5.0 percent as calculated using Equation A–4 of this appendix; or

(2) The absolute value of the difference between the average of the monitor response values and the average of the reference values, $|R-A|$ in Equation A–4 of this appendix, shall be less than or equal to 0.5 percent CO_2 or O_2, whichever is less restictive.

3.3 Relative Accuracy

3.3.1 Relative Accuracy for SO_2

The relative accuracy for SO_2 pollutant concentration monitors and for SO_2-diluent continuous emission monitoring systems used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, shall not exceed 10.0 percent except as provided below in this section.

For affected units where the average of the monitor measurements of SO_2 concentration during the relative accuracy test audit is less than or equal to 250.0 ppm (or for SO_2-diluent monitors, less than or equal to 0.5 lb/mmBTU), the mean value of the monitor

measurements shall not exceed ±15.0 ppm of the reference method mean value (or, for SO_2-diluent monitors, not to exceed ±0.03 lb/mmBTU for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999) wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.2 Relative Accuracy for NO_x

The relative accuracy for NO_x continuous emission monitoring systems shall not exceed 10.0 percent.

For affected units where the average of the monitoring system measurements of NO_x emission rate during the relative accuracy test audit is less than or equal to 0.20 lb/mmBtu, the mean value of the NO_x continuous emission monitoring system measurements shall not exceed ±0.02 lb/mmBtu of the reference method mean value wherever the relative accuracy specification of 10.0 percent is not achieved.

3.3.3 Relative Accuracy for CO_2 Pollutant Concentration Monitors

The relative accuracy for CO_2 monitors shall not exceed 10 percent. The relative accuracy test results are also acceptable if the mean difference of the CO_2 monitor measurements and the corresponding reference method measurement, calculated using Equation A–7 of this appendix, is within ±1.0 percent CO_2.

3.3.4 Relative Accuracy for Flow

Except as provided below in this section, the relative accuracy for flow monitors, where volumetric gas flow is measured in scfh, shall not exceed 15.0 percent through December 31, 1999. Beginning on January 1, 2000, (except as provided below in this section) the relative accuracy of flow monitors shall not exceed 10.0 percent.

For affected units where the average of the flow monitor measurements of gas velocity during one or more operating levels of the relative accuracy test audit is less than or equal to 10.0 fps, the mean value of the flow monitor velocity measurements shall not exceed ±2.0 fps of the reference method mean value in fps wherever the relative accuracy specification above is not achieved.

3.3.5 Combined SO_2/Flow Monitoring System [Reserved]

3.4 Bias

3.4.1 SO_2 Pollutant Concentration Monitors and NO_x Continuous Emission Monitoring Systems.

SO_2 pollutant concentration monitors and NO_x continuous emission monitoring systems shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all SO_2 pollutant concentration monitors, including those measuring an average SO_2 concentration of 250.0 ppm or less, and to all NO_x continuous emission monitoring systems, including those measuring an average NO_x emission rate of 0.20 lb/mmBtu or less

3.4.2 Flow Monitors

Flow monitors shall not be biased low as determined by the test procedure in section 7.6 of this appendix. The bias specification applies to all flow monitors including those measuring an average gas velocity of 10.0 fps or less.

3.5 Cycle Time/Response Time

The cycle time/response time for pollutant concentration monitors, and continuous emission monitoring systems shall not exceed 15 min.

4. Data Acquisition and Handling Systems

Automated data acquisition and handling systems shall: (1) Read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission via an IBM-compatible personal computer diskette or other electronic media. These systems also shall have the capability of interpreting and converting the individual output signals from an SO_2 pollutant concentration monitor, a flow monitor, and a NO_x continuous emissions monitoring system to produce a continuous readout of pollutant mass emission rates in the units of the standard. Where CO_2 emissions are measured with a continuous emission monitoring system, the data acquisition and handling system shall also produce a readout of CO_2 mass emissions in tons.

Data acquisition and handling systems shall also compute and record monitor calibration error; any bias adjustments to pollutant concentration, flow rate, or NO_x emission rate data; and all missing data procedure statistics specified in subpart D of this part.

5. Calibration Gas

5.1 Reference Gases

For the purposes of part 75, calibration gases include the following.

5.1.1 Standard Reference Materials

These calibration gases may be obtained from the National Institute of Standards and Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg, Maryland 20899.

5.1.2 NIST/EPA-Approved Certified Reference Materials

A current list of certified reference material cylinder gases and certified reference material vendors is available from the Quality Assurance Division (MD 77), Environmental Monitoring System Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

5.1.3 EPA Traceability Protocol 1 Gases

Protocol 1 gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value).

5.2 Concentrations

Four concentration levels are required as follows.

5.2.1 Zero-level Concentration

0 to 20 percent of span, including span for high scale or both low- and high-scale for SO_2 and NO_x pollutant concentration monitors, as appropriate.

5.2.2 Low-level Concentration

20 to 30 percent of span, including span for high scale or both low- and high-scale for SO_2 and NO_x pollutant concentration monitors, as appropriate.

5.2.3 Mid-level Concentration

50 to 60 percent of span, including span for high scale or both low- and high-scale for SO_2 and NO_x pollutant concentration monitors, as appropriate.

5.2.4 High-level Concentration

80 to 100 percent of span, including span for high scale or both low- and high-scale for SO_2 and NO_x pollutant concentration monitors, as appropriate.

6. Certification Tests and Procedures

6.1 Pretest Preparation

Install the components of the continuous emission monitoring system (i.e., pollutant concentration monitors, CO_2 or O_2 monitor, and flow monitor) as specified in sections 1, 2, and 3 of this appendix, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instructions. Operate the unit(s) during each period when measurements are made. Units may be tested on non-consecutive days.

6.2 Linearity Check

Measure the linearity of each pollutant concentration monitor and CO_2 or O_2 monitor according to the following procedures.

Challenge each pollutant concentration or CO_2 or O_2 monitor with NIST/EPA-approved certified reference material, standard reference material, or Protocol 1 calibration gases certified to be within 2 percent of the concentration specified on the label at the low-, mid-, or high-range concentrations specified in section 5.2 of this appendix. For units using emission controls and other units using a maximum expected concentration value to determine calibration gases, perform a linearity check on both the low- and high-scales.

Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor at its normal operating temperature and conditions. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer.

Repeat the procedure for SO_2 and NO_x pollutant concentration monitors using the low-scale for units equipped with emission controls with dual span monitors. Challenge the monitor three times with each reference gas. Do not use the same gas twice in succession. Record the monitor response from the data acquisition and handling system (see example data sheet in Figure 1). For each concentration, use the average of the responses to determine the error in linearity using Equation A–4 in this appendix.

Linearity checks are acceptable for monitor or monitoring system certification if none of

the test results exceed the applicable performance specifications in section 3.2 of this appendix.

6.3 7-Day Calibration Error Test

6.3.1 7-day Calibration Error Test for Pollutant Concentration Monitors and CO_2 and O_2 Monitors

Measure the calibration error of each pollutant concentration monitor and CO_2 or O_2 monitor 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 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 adjustments to the monitor settings during the 7-day test. If automatic adjustments are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

The calibration error tests should, to the extent practicable, 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/EPA-approved certified reference material, standard reference material or Protocol 1 calibration gases certified by the vendor to be within 2 percent of the label value.

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 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.

6.3.2 7-Day Calibration Error Test for Flow Monitors

Measure the calibration error of each flow monitor according to the following procedures.

Introduce the reference signal corresponding to the values specified in section 2.2.2.1 of this appendix to the probe tip (or equivalent), or to the transducer. During the 7-day certification test period, conduct the calibration error test once each day while the unit is operating (as close to 24-hour intervals as practicable). In the event that extended unit outages occur after the commencement of the test, the 7 consecutive operating days need not be 7 consecutive calendar days. Record the flow monitor responses by means of the data acquisition and handling system. Calculate the calibration error using Equation A–6 of this appendix.

Do not perform any corrective maintenance, repair, replacement or manual adjustment upon the flow monitor during the 7-day certification test period other than that required in the monitor operation and maintenance manual. If the flow monitor operates within the calibration error performance specification, (i.e., less than or equal to 3 percent error each day and does not require corrective maintenance, repair, replacement or manual adjustment during the 7-day test period) the flow monitor passes the calibration error test portion of the certification test. Wherever automatic adjustments are made, record the magnitude of the adjustments. Record all maintenance and required adjustments. Record output readings from the data acquisition and handling system before and after all adjustments.

6.4 Cycle Time/Response Time Test

Perform cycle time/response time tests for each pollutant concentration monitor, and continuous emission monitoring system according to the following procedures. Use a low-level and a high-level calibration gas (as defined in section 5.2 of this appendix) alternately. While the monitor or monitoring system is measuring and recording the concentration or emission rate, inject either a low-level concentration or a high-level concentration calibration gas into the injection port. Continue injecting the gas until a stable response is reached. Record the amount of time required for the monitor or monitoring system to complete 95.0 percent of the concentration or emission rate stepchange using data acquisition and handling system output. Then repeat the procedure with the other gas. 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 response time. (Note: for the NO_x continuous emission monitoring system test and SO_2-diluent continuous emission monitoring system test, it will be necessary to simultaneously inject calibration gases into the pollutant and diluent monitors, in order to measure the step change in the lb/mmBtu emission rate.)

Cycle time/response time test results are acceptable for monitoring or monitoring system certification if none of the response times exceed 15 min.

6.5 Relative Accuracy and Bias Tests

Perform relative accuracy test audits for each CO_2 and SO_2 pollutant concentration monitor, each SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, flow monitor, and NO_x continuous emission monitoring system. Record monitor or monitoring system output from the data acquisition and handling system. Perform concurrent relative accuracy test audits for each SO_2 pollutant concentration monitor and flow monitor, at least once a year (see section 2.3.1 of Appendix B of this part), during the flow monitor test at the normal operating level specified in section 6.5.2 of this appendix. Concurrent relative accuracy test audits may be performed by conducting simultaneous SO_2 and flow relative accuracy test audit runs, or by alternating an SO_2 relative accuracy test audit run with a flow relative accuracy test audit run until all relative accuracy test audit runs are completed. Where two or more probes are in the same proximity, care should be taken to prevent probes from interfering with each other's sampling. For each SO_2 pollutant concentration monitor, each flow monitor, and each NO_x continuous emission monitoring system, calculate bias, as well as relative accuracy, with data from the relative accuracy test audits.

Complete each relative accuracy test audit within a 7-day period while the unit (or units, if more than one unit exhausts into the flue) is combusting its primary fuel. When relative accuracy test audits are performed on continuous emission monitoring systems or component(s) on bypass stacks/ducts, use the fuel normally combusted by the unit (or units, if more than one unit exhausts into the flue) when emissions exhaust through the bypass stack/ducts. Do not perform corrective maintenance, repairs, replacements or adjustments during the relative accuracy test audit other than as required in the operation and maintenance manual.

6.5.1 SO_2 and CO_2 Pollutant Concentration Monitors and SO_2 and NO_x Continuous Emission Monitoring Systems

Perform relative accuracy test audits for each SO_2 or CO_2 pollutant concentration monitor or NO_x continuous emission monitoring system or SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, at a normal operating level for the unit (or combined units, if common stack).

6.5.2 Flow Monitors

Except for flow monitors on bypass stacks/ducts and peaking units, perform relative accuracy test audits for each flow monitor at three different exhaust gas velocities, expressed in terms of percent of flow monitor span, or different operating or load levels. For a common stack/duct, the three different exhaust gas velocities may be obtained from frequently used unit/load combinations for units exhausting to the common stack. Select the operating levels as follows: (1) A frequently used low operating level selected

within the range between the minimum safe and stable operating level and 50% load, (2) a frequently used high operating level selected within the range between 80 percent of the maximum operating level and the maximum operating level, and (3) the normal operating level. If the normal operating level is within a specified range, [10.0 percent of the maximum operating level] of either (1) or (2) above, use a level that is evenly spaced between the low and high operating levels used. The maximum operating level shall be equal to the nameplate capacity less any physical or regulatory limitations or other deratings. Calculate flow monitor relative accuracy at each of the three operating levels. If a flow monitor fails the relative accuracy test on any of the three levels of a three-level relative accuracy test audit, the three-level relative accuracy test audit must be repeated. For flow monitors on bypass stacks/ducts and peaking units, the flow monitor relative accuracy test audit is required only at the normal operating level.

6.5.3 CO_2 Pollutant Concentration Monitors

Perform relative accuracy test audits for each CO_2 monitor (measuring in percent CO_2) at a normal operating level for the unit (or combined units, if common stack).

6.5.4 Calculations

Using the data from the relative accuracy test audits, calculate relative accuracy and bias in accordance with the procedures and equations specified in section 7 of this appendix.

6.5.5 Reference Method Measurement Location

Select a location for reference method measurements that is (1) accessible; (2) in the same proximity as the monitor or monitoring system location; and (3) meets the requirements of Performance Specification 2 in Appendix B to part 60 of this chapter for SO_2 and NO_x continuous emission monitoring systems, or Method 1 (or 1A) in Appendix A to part 60 of this chapter for volumetric flow, except as otherwise indicated in this section.

6.5.6 Reference Method Traverse Point Selection

Select traverse points that (1) ensure acquisition of representative samples of pollutant and diluent concentrations, moisture content, temperature, and flue gas flow rate over the flue cross section; and (2) meet the requirements of Performance Specification 2 in Appendix B to part 60 of this chapter (for SO_2 and NO_x), Method 1 (or 1A) (for volumetric flow), Method 3 (for O_2 CO_2 and dry molecular weight), and Method 4 (for moisture determination) in Appendix A to part 60 of this chapter.

6.5.7 Sampling Strategy

Conduct the reference method tests so they will yield results representative of the pollutant concentration, emission rate, moisture, temperature, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, CO_2 or O_2 monitor, flow monitor, and SO_2 or NO_x continuous emission monitoring system measurements. Conduct the diluent (O_2 or CO_2) measurements and any moisture measurements that may be needed simultaneously with the pollutant concentration and flue gas flow rate measurements. To properly correlate individual SO_2 and CO_2 pollutant concentration monitor data, SO_2 or NO_x continuous emission monitoring system data (in lb/mmBtu), and volumetric flow rate data with the reference method data, mark the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

6.5.8 Correlation of Reference Method and Continuous Emission Monitoring System

Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, temperature, and diluent concentration basis (e.g., since the flow monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis). Compare flow-monitor and reference method results on a scfh basis. Also, consider the response times of the pollutant concentration monitor, the continuous emission monitoring system, and the flow monitoring system to ensure comparison of simultaneous measurements.

For each relative accuracy test audit run, compare the measurements obtained from the monitor or continuous emission monitoring system (in ppm, percent CO_2, lb/mmBtu, or other units) against the corresponding reference method values. Tabulate the paired data in a table such as the one shown in Figure 2.

6.5.9 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required (i.e., certification, semiannual, or annual) relative accuracy or bias test audit. For the certification and annual quality assurance relative accuracy test audits for flow monitors, perform a minimum of nine sets at each of the three operating levels specified in section 6.5.2 of this appendix. Conduct each set within a period of 30 to 60 minutes.

Note: The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results as long as the total number of test results used to determine the relative accuracy or bias is greater than or equal to nine. Report all data, including the rejected data, and reference method test results.

6.5.10 Reference Methods

The following methods from Appendix A to part 60 of this chapter or their approved alternatives are the reference methods for performing relative accuracy test audits: Method 1 or 1A for siting; Method 2 (or 2A, 2C, or 2D) for velocity; Methods 3, 3A, or 3B for O_2 or CO_2; Method 4 for moisture; Methods 6, 6A, or 6C for SO_2; Methods 7, 7A, 7C, 7D, 7E for NO_x; and Method 20 for determination of NO_x, SO_2, and O_2 or CO_2 from stationary gas turbines.

7. Calculations

7.1 Linearity Check

Analyze the linearity data for pollutant concentration and CO_2 or O_2 monitors as follows. Calculate the percentage error in linearity based upon the reference value at the low-level, mid-level, and high-level concentrations specified in section 6.2 of this appendix. Perform this calculation once during the certification test. Use the following equation to calculate the error in linearity for each reference value.

$$LE = \frac{|R-A|}{R} \times 100$$

(Eq. A–4)

where,

LE=Percentage Linearity error, based upon the reference value.

R=Reference value of Low-, mid-, or high-level calibration gas introduced into the monitoring system.

A=Average of the monitoring system responses.

7.2 Calibration Error

7.2.1 Pollutant Concentration and Diluent Monitors

For each reference value, calculate the percentage calibration error based upon instrument span for daily calibration error tests using the following equation:

$$CE = \frac{|R-A|}{S} \times 100$$

(Eq. A–5)

where,

CE=Percentage Calibration error based upon span of the instrument.

R=Reference value of zero- or high-level calibration gas introduced into the monitoring system.

A=Actual monitoring system response to the calibration gas.

S=Span of the instrument, as specified in Section 2 of this appendix.

7.2.2 Flow Monitor Calibration Error

For each reference value, calculate the percentage calibration error based upon span using the following equation:

$$CE = \frac{|R-A|}{S} \times 100$$

(Eq. A–6)

where,

CE=Calibration error;

R=Low or high level reference value specified in section 2.2.2.1 of this appendix;

A=Actual flow monitor response to the reference value; and

S=Flow monitor span.

Whenever the flow rate exceeds the monitor's ability to measure and record values accurately, adjust the span to prevent future exceedances. If process parameters change or other changes are made such that the expected flue gas velocity may change significantly, adjust the span to assure the continued accuracy of the monitoring system.

7.3 Relative Accuracy for SO_2 and CO_2 Pollutant Concentration Monitors, SO_2 Continuous Emission Monitoring Systems, and Flow Monitors

Analyze the relative accuracy test audit data from the reference method tests for SO_2 and CO_2 pollutant concentration monitors, SO_2-diluent continuous emission monitoring systems (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, and flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 2. Calculate the mean of the monitor or monitoring system measurement values. Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor or monitoring system relative accuracy using the following procedures and equations.

7.3.1 Arithmetic Mean

Calculate the arithmetic mean of the differences, $\bar{d}$, of a data set as follows.

$$\bar{d} = \frac{1}{n}\sum_{i=1}^{n} d_i$$

(Eq. A–7)

where,

n=Number of data points.

$\sum_{i=1}^{n} d_i$=Algebraic sum of the individual differences d_i.

d_i=The difference between a reference method value and the corresponding continuous emission monitoring system value (RM_i–CEM_i) at a given point in time i.

When calculating the arithmetic mean of the difference of a flow monitor data set, be sure to correct the monitor measurements for moisture if applicable.

7.3.2 Standard Deviation

Calculate the standard deviation, S_d, of a data set as follows:

$$S_d = \sqrt{\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\left(\sum_{i=1}^{n} d_i\right)^2}{n}\right]}{n-1}}$$

(Eq. A–8)

7.3.3 Confidence Coefficient

Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

$$cc = t_{0.025}\frac{S_d}{\sqrt{n}}$$

(eq. A–9)

where,

$t_{0.025}$=t value (see Table 7–1).

TABLE 7–1 T-VALUES

n-1	$t_{0.025}$	n-1	$t_{0.025}$	n-1	$t_{0.025}$
1	12.706	12	2.179	23	2.069
2	4.303	13	2.160	24	2.064
3	3.182	14	2.145	25	2.060
4	2.776	15	2.131	26	2.056
5	2.571	16	2.120	27	2.052
6	2.447	17	2.110	28	2.048
7	2.365	18	2.101	29	2.045
8	2.306	19	2.093	30	2.042
9	2.262	20	2.086	40	2.021
10	2.228	21	2.080	60	2.000
11	2.201	22	2.074	>60	1.960

7.3.4 Relative Accuracy

Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|\bar{d}| + |cc|}{\overline{RM}} \times 100$$

(Eq. A–10)

where,

RM=Arithmetic mean of the reference method values.

|d|=The absolute value of the mean difference between the reference method values and the corresponding continuous emission monitoring system values.

|cc|=The absolute value of the confidence coefficient.

7.4 Relative Accuracy for NO_x Continuous Emission Monitoring Systems

Analyze the relative accuracy test audit data from the reference method tests for NO_x continuous emissions monitoring system as follows.

7.4.1 Data Preparation

If C_{NOx}, the NO_x concentration, is in ppm, multiply it by 1.194×10^{-7} (lb/dscf)/ppm to convert it to units of lb/dscf. If C_{NOx} is in mg/dscm, multiply it by 6.24×10^{-8} (lb/dscf)/(mg/dscm) to convert it to lb/dscf. Then, use the diluent (O_2 or CO_2) reference method results for the run and the appropriate F or F_c factor from Table 1 in Appendix F of this part to convert C_{NOx} from lb/dscf to lb/mmBtu units. Use the equations and procedure in section 3 of Appendix F to this part, as appropriate.

7.4.2 NO_x Emission Rate (Monitoring System)

For each test run in a data set, calculate the average NO_x emission rate (in lb/mmBtu), by means of the data acquisition and handling system, during the time period of the test run. Tabulate the results as shown in example Figure 4.

7.4.3 Relative Accuracy

Use the equations and procedures in section 7.3 above to calculate the relative accuracy for the NO_x continuous emission monitoring system. In using Equation A–7, "d" is, for each run, the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method data and the NO_x continuous emission monitoring system.

7.5 Relative Accuracy for Combined SO_2/Flow [Reserved]

7.6 Bias Test and Adjustment Factor

Test the relative accuracy test audit data sets for SO_2 pollutant concentration monitors, flow monitors, and NO_x continuous emission monitoring systems for bias using the procedures outlined below.

7.6.1 Arithmetic Mean

Calculate the arithmetic mean of the difference, $\bar{d}$, of the data set using Equation A–7 of this appendix. To calculate bias for an SO_2 pollutant concentration monitor, "d" is, for each paired data point, the difference between the SO_2 concentration value (in ppm) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d" is, for each paired data point, the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for a NO_x continuous emission monitoring system, "d" is, for each paired data point, the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method and the monitoring system.

7.6.2 Standard Deviation

Calculate the standard deviation, S_d, of the data set using Equation A–8.

7.6.3 Confidence Coefficient

Calculate the confidence coefficient, cc, of the data set using Equation A–9.

7.6.4 Bias Test

If the mean difference, $\bar{d}$, is greater than the absolute value of the confidence coefficient, |cc|, the monitor or monitoring system has failed to meet the bias test requirement. For flow monitor bias tests, if the mean difference, $\bar{d}$, is greater than |cc| at the normal operating level (or equally spaced intermediary level), the monitor has failed to meet the bias test requirement. For flow monitors, apply the bias test at normal operating level (or an evenly spaced intermediary level).

7.6.5 Bias Adjustment

If the monitor or monitoring system fails to meet the bias test requirement, adjust the value obtained from the monitor using the following equation:

$CEM_i^{Adjusted} = CEM_i^{Monitor} \times BAF$

(Eq. A–11)

where,

$CEM_i^{Monitor}$=Data (measurements) provided by the monitor at time i.

$CEM_i^{Adjusted}$=Data value, adjusted for bias, at time i.

BAF=Bias adjustment factor, defined by

$$BAF = 1 + \frac{|\bar{d}|}{CEM}$$

(Eq. A–12)

where,

$\bar{d}$=Arithmetic mean of the difference obtained during the failed bias test using Equation A–7.

CEM=Mean of the data values provided by the monitor during the failed bias test.

If the bias test is failed by a flow monitor on a 3-level relative accuracy test audit, calculate the bias adjustment factor for each of the three operating levels. Apply the largest of the three bias adjustment factors to subsequent flow monitor data using Equation A–11.

Apply this adjustment prospectively to all monitor or monitoring system data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias. Use the adjusted values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the emitted tons of SO_2 and CO_2 and the average NO_x emission rate during the quarter and calendar year, as specified in subpart G of this part.

FIGURE 1.—LINEARITY ERROR DETERMINATION

Day	Date and time	Reference value	Monitor value	Difference	Percent of reference value
Low-level					
Mid-level					
High-level					

FIGURE 2.—RELATIVE ACCURACY DETERMINATION (POLLUTANT CONCENTRATION MONITORS)

Run No.	Date and time	SO_2 (ppm[c])			Date and time	CO_2 (Pollutant) (ppm[c])		
		RM[a]	M[b]	Diff		RM[a]	M[b]	Diff
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
Arithmetic Mean Difference (Eq. A–7).								
Confidence Coefficient (Eq. A–9).								
Relative Accuracy (Eq. A–10).								

[a] RM means "reference method data."
[b] M means "monitor data."
[c] Make sure that RM and M data are on a consistent basis, either wet or dry.

FIGURE 3.–RELATIVE ACCURACY DETERMINATION (FLOW MONITORS)

Run No.	Date and time	Flow rate (Low) (scf/hr) *			Date and time	Flow rate (Normal) (scf/hr) *			Date and time	Flow rate (High) (scf/hr) *		
		RM	M	Diff		RM	M	Diff		RM	M	Diff
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
Arithmetic Mean Difference (eq. A–7). Confidence Coefficient (eq. A–9). Relative Accuracy (eq. A–10).												

*Make sure that RM and M data are on a consistent moisture basis.

FIGURE 4:—RELATIVE ACCURACY DETERMINATION (NO_x/diluent combined system)

Run No.	Date and time	Reference method data		NO_x system (lb/mmBtu)		
		NO_x ( )*	O_2/CO_2%	RM	M	Difference
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
Arithmetic Mean Difference (eq. A–7).						

FIGURE 4:—RELATIVE ACCURACY DETERMINATION (NO_x/diluent combined system)—Continued

Run No.	Date and time	Reference method data		NO_x system (lb/mmBtu)		
		NO_x ( )*	O_2/CO_2%	RM	M	Difference
Confidence Coefficient (eq. A–9). Relative Accuracy (eq. A–10).						
*Specify units: ppm, lb/dscf,mg/dscm.						

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

1. Quality Control Program

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities.

1.1 Calibration Error Test and Linearity Check Procedures

Identify calibration error test and linearity check procedures specific to the continuous emission monitoring system that may require variance from the procedures in Appendix A to this part (e.g., how gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error or error in linearity, determination of interferences, and when calibration adjustments should be made).

1.2 Calibration and Linearity Adjustments

Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each continuous emission monitoring system.

1.3 Preventive Maintenance

Keep a written record of procedures, including those specified by the manufacturers, needed to maintain the continuous emission monitoring system in proper operating condition and a schedule for those procedures. Include provisions for maintaining an inventory of spare parts.

1.4 Audit Procedures

Keep a written record of procedures and details peculiar to the installed continuous emission monitoring system that are to be used for relative accuracy test audits, such as sampling and analysis methods.

1.5 Recordkeeping and Reporting

Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements in subparts F and G of this part.

2. Frequency of Testing

A summary chart showing each quality assurance test and the frequency at which each test is required is located at the end of this appendix in Figure 1.

2.1 Daily Assessments

For each monitor or continuous emission monitoring system, perform the following assessments during each day in which the unit combusts any fuel (hereafter referred to as a "unit operating day"), or for a monitor or continuous emission monitoring system on a bypass stack/duct, during each day that emissions pass through the by-pass 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 for Pollutant Concentration and CO_2 or O_2 Monitors

Test, record, and compute the calibration error of each SO_2 or NO_x pollutant concentration and CO_2 or O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass ducts/stacks, on each day that emissions pass through the by-pass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Appendix A, section 6.3.1 of this part.

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

2.1.2 Calibration Error Test for Flow Monitors

Test, compute, and record the calibration error of each flow monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass ducts/stacks, on each day that emissions pass through the by-pass stack or duct. Introduce the reference values (specified in section 2.2.2.1 of Appendix A to this part) to the probe tip (or equivalent) or to the transducer. Record flow monitor output from the data acquisition and handling system before and after any adjustments to the flow monitor. Keep a record of all maintenance and adjustments. Calculate the calibration error using Equation A–6 in Appendix A of this part.

2.1.3 Interference Check

Perform the daily flow monitor interference checks specified in section 2.2.2.2 of Appendix A to this part at least once per operating day (when the unit(s) operate for any part of the day).

2.1.4 Recalibration

Adjust the calibration, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification for the pollutant concentration monitor, CO_2, or O_2 monitor, or flow monitor in Appendix A of this part. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective.

2.1.5 Out-of-Control Period

An out-of-control period occurs when the calibration error of an SO_2 or NO_x pollutant concentration monitor exceeds 5.0 percent based upon the span value (or exceeds 10 ppm, for span values <200 ppm), when the calibration error of a diluent gas monitor exceeds 1.0 percent O_2 or CO_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span value, which is twice the applicable specification of Appendix A of this part. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out of control if 2 or more valid readings are obtained during that hour as required by § 75.10 of this part. A NO_x continuous emission monitoring system is considered out-of-control if either component monitor exceeds twice the applicable specification in Appendix A of this part.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed.

2.1.6 Data Recording

Record and tabulate all calibration error test data according to month, day, clock-hour, and magnitude in either ppm, percent volume, or scfh. Program monitors that automatically adjust data to the corrected

calibration values (e.g., microprocessor control) to record either: (1) The unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) Sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2.2 Quarterly Assessments

For each monitor or continuous emission monitoring system, perform the following assessments during each calendar quarter in which the unit combusts any fuel (hereafter referred to as a "unit operating quarter"), or for monitors or monitoring systems on bypass ducts/stacks, during each calendar quarter that emissions pass through the by-pass stack or duct (hereafter referred to as a "bypass operating quarter"). This requirement is effective as of the calendar quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

2.2.1 Linearity Check

Perform a linearity check for each SO_2 and NO_x pollutant concentration monitor and each CO_2 or O_2 monitor at least once during each unit operating quarter or each bypass operating quarter, in accordance with the procedures in Appendix A, section 6.2 of this part. For units using emission controls and other units using a low-scale span value to determine calibration gases, perform a linearity check on both the low- and high-scales. For the linearity check, use calibration gas cylinders that are different cylinders from the ones used in the daily calibration error tests. Conduct the linearity checks no less than 2 months apart.

2.2.2 Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each unit operating quarter or each bypass operating quarter. Conduct the leak checks no less than 2 months apart.

2.2.3 Out-of-Control Period

An out-of-control period occurs when the error in linearity at any of the three concentrations (six for dual range monitors) in the quarterly linearity check exceeds the applicable specification in Appendix A, section 3.2 of this part. The out-of-control period begins with the hour of the failed linearity check and ends with the hour of a satisfactory linearity check following corrective action and/or monitor repair. For the NO_x continuous emission monitoring system, the system is considered out-of-control if either of the component monitors exceed the applicable specification in Appendix A, section 3.2 of this part. An out-of-control period occurs when a flow monitor sample line leak is detected. The out-of-control period begins with the hour of the failed leak check and ends with the hour of a satisfactory leak check following corrective action.

2.3 Semiannual and Annual Assessments

For each monitor or continuous emission monitoring system, perform the following assessments once semiannually or once annually after the calendar quarter in which the monitor or monitoring system was last tested, as specified below for the type of test and the performance achieved. For monitors or continuous emission monitoring systems on bypass ducts/stacks, the assessments are to be performed once every two successive bypass operating quarters or once every four successive operating quarters after the calendar quarter in which the monitor or monitoring system was last tested, as specified below for the type of test and the performance achieved. This requirement is effective as of the calendar quarter or bypass operating quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified. A summary chart showing the frequency with which a relative accuracy test audit must be performed, depending on the accuracy achieved, is located at the end of this appendix in Figure 2.

23.1 Relative Accuracy Test Audit

Perform relative accuracy test audits semiannually and no less than 4 months apart for each SO_2 or CO_2 pollutant concentration monitor, flow monitor, NO_x continuous emission monitoring system, for SO_2-diluent continuous emission monitoring systems used by units with a Phase I Qualifying technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, in accordance with the procedures in section 6.5 of Appendix A of this part. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with the procedures in section 6.5 of Appendix A of this part. Successive audits shall be no less than 4 months apart. The audit frequency may be reduced, as specified below for monitors or monitoring systems which qualify for less frequent testing.

For flow monitors, one-level and three-level relative accuracy test audits shall be performed alternately (when a flow RATA is conducted semiannually), such that the three-level relative accuracy test audit is performed at least once annually. The three-level audit shall be performed at the three different operating or load levels specified in Appendix A, section 6.5.2 of this part, and the one-level audit shall be performed at the normal operating or load level. Relative accuracy test audits need only be performed once every two successive unit or bypass operating quarters at the normal operating or load level for monitors and continuous emission monitoring systems on peaking units and bypass stacks/ducts.

Relative accuracy test audits may be performed on an annual basis rather than on a semiannual basis under any of the following conditions (or for monitors on peaking units and bypass ducts/stacks, once every four successive unit or bypass operating quarters): (1) The relative accuracy during the previous audit for an SO_2 or CO_2 pollutant concentration monitor, or NO_x or SO_2 continuous emissions monitoring system is 7.5 percent or less; (2) prior to January 1, 2000, the relative accuracy during the previous audit for a flow monitor is 10.0 percent or less at each operating level tested; (3) on and after January 1, 2000, the relative accuracy during the previous audit for a flow monitor is 7.5 percent or less at each operating level tested; (4) on low flow (≤10.0 fps) stacks/ducts, when the monitor mean, calculated using Equation A–7 in Appendix A of this part is within ±1.5 fps of the reference method mean or achieves a relative accuracy of 7.5 percent (10 percent if prior to January 1, 2000) or less during the previous audit; (5) on low SO_2 emitting units (SO_2 concentrations ≤250.0 ppm), when the monitor mean is within ±8.0 ppm (or equivalent in lb/mmBTU for SO_2-diluent monitors) of the reference method mean or achieves a relative accuracy of 7.5 percent or less (or equivalent lb/mmBTU value for SO_2-diluent monitors) during the previous audit; or (6) on low NO_x emitting units (NO_x emission rate ≤0.20 lb/mmbtu), when the NO_x continuous emission monitoring system achieves a relative accuracy of 7.5 percent or less.

A maximum of two relative accuracy test audit trials may be performed for the purpose of achieving the results required to qualify for less frequent relative accuracy test audits. Whenever two trials are performed, the results of the second (later) trial must be used in calculating both the relative accuracy and bias.

2.3.2 Out-of-Control Period

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an SO_2 pollutant concentration monitor or a NO_x or SO_2 continuous emission monitoring system exceeds 10.0 percent; (2) prior to January 1, 2000, the relative accuracy of a flow monitor exceeds 15.0 percent; (3) on and after January 1, 2000, the relative accuracy of a flow monitor exceeds 10.0 percent; (4) for low flow situations (≤10.0 fps), the flow monitor mean value (if applicable) exceeds±2.0 fps of the reference method mean whenever the relative accuracy is greater than 15.0 percent for Phase I or 10 percent for Phase II; (5) for low SO_2 emitter situations, the monitor mean values exceeds ±15.0 ppm of the reference method mean whenever the relative accuracy is greater than 10.0 percent; or (6) for low NO_x emitting units (NO_x emission rate ≤0.2 lb/mmbtu), the NO_x continuous emission monitoring system mean values exceed ±0.02 lb/mmBtu of the reference method mean whenever the relative accuracy is greater than 10.0 percent. For SO_2, NO_x emission rate, and flow relative accuracy test audits performed at only one level, the out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit. For a flow relative accuracy test audit at 3 operating levels, the out-of-control period begins with the hour of completion of the first failed relative accuracy test audit at any of the three operating levels, and ends with the hour of completion of a satisfactory three-level relative accuracy test audit.

Failure of the bias test does not result in the system or monitor being out-of-control.

the bias adjustment factor given in Equations A–11 and A–12 of Appendix A to this part to adjust the monitored data.

2.4 Other Audits

Affected units may be subject to relative accuracy test audits at any time. If a monitor or continuous emission monitoring system fails the relative accuracy test during the audit, the monitor or continuous emission monitoring system shall be considered to be out-of-control beginning with the date and time of completion of the audit, and continuing until a successful audit test is completed following corrective action. If a monitor or monitoring system fails the bias test during an audit, use the bias adjustment factor given by Equations A–11 and A–12 in Appendix A to this part to adjust the monitored data. Apply this adjustment factor from the date and time of completion of the audit until the date and time of completion of a relative accuracy test audit that does not show bias.

FIGURE 1.—QUALITY ASSURANCE TEST REQUIREMENTS

Test	QA test frequency requirements		
	Daily*	Quarterly*	Semiannual*
Calibration Error (2 pt.).	√		
Interference (flow).	√	√	
Linearity (3 pt.).		√	

FIGURE 1.—QUALITY ASSURANCE TEST REQUIREMENTS—Continued

Test	QA test frequency requirements		
	Daily*	Quarterly*	Semiannual*
RATA (SO_2, NO_x, CO_2)[1].			√
RATA (flow, alternating 1-load and 3-load)[2].			√

*For monitors on bypass stack/duct, bypass operating days or quarters, only.
[1]Conduct annually, if monitor meets accuracy requirements to qualify for less frequent testing.
[2]Conduct 3-load RATAs annually, if requirements to qualify for less frequent testing are met.

FIGURE 2.—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM

RATA	Semiannually*	Annual*
SO_2	RA ≤ 10%	RA ≤ 7.7% or ± 8ppm**
NO_x	RA ≤ 10%	RA ≤ 7.5%
Flow (Phase I)[3]	RA ≤ 15%	RA ≤ 10% or ± 1.5 fps**
Flow (Phase II)[3]	RA ≤ 10%	RA ≤ 7.5% or ± 1.5 fps**

*For monitors on bypass stack/duct, bypass operating quarters, only.
**The difference between monitor and reference method mean values; low emitters or low flow, only.
[3]Conduct 3-load RATAs annually, if requirements to qualify for less frequent testing are met.

Appendix C to Part 75—Missing Data Estimation Procedures

1. Parametric Monitoring Procedure for Missing SO_2 Concentration or NO_x Emission Rate Data

1.1 Applicability

The owner or operator of any affected unit equipped with post-combustion SO_2 or NO_x emission controls and SO_2 pollutant concentration monitors and/or NO_x continuous emission monitoring systems at the inlet and outlet of the emission control system may apply to the Administrator for approval and certification of a parametric, empirical, or process simulation method or model for calculating substitute data for missing data periods. Such methods may be used to parametrically estimate the removal efficiency of the SO_2 of postcombustion NO_x emission controls which, with the monitored inlet concentration or emission rate data, may be used to estimate the average concentration of SO_2 emissions or average emission rate of NO_x discharged to the atmosphere. After approval by the Administrator, such method or model may be used to for filling in missing SO_2 concentration or NO_x emission rate data when data from the outlet SO_2 pollutant concentration monitor or outlet NO_x continuous emission monitoring system have been reported with an annual monitor data availability of 90.0 percent or more.

Base the empirical and process simulation methods or models on the fundamental chemistry and engineering principles involved in the treatment of pollutant gas. On a case-by-case basis, the Administrator may pre-certify commercially available process simulation methods and models.

1.2 Demonstration Requirements

Continuously monitor, determine, and record hourly averages for the parameters specified below, at a minimum. The affected facility shall supply additional parametric information where appropriate. At least 4 evenly spaced data points are required for a valid hourly average, except during periods of calibration, maintenance, or quality assurance activities, during which 2 data points per hour are sufficient. The Administrator will review all applications on a case-by-case basis.

1.2.1 Parameters for Wet Flue Gas Desulfurization System

1.2.1.1 Number of scrubber modules in operation.

1.2.1.2 Total slurry rate to each scrubber module (gal per min).

1.2.1.3 In-line absorber pH of each scrubber module.

1.2.1.4 Pressure differential across each scrubber module (inches of water column).

1.2.1.5 Unit load (MWe).

1.2.1.6 Inlet and outlet SO_2 concentration as determined by the monitor or missing data substitution procedures.

1.2.1.7 Percent solids in slurry for each scrubber module.

1.2.1.8 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.2 Parameters for Dry Flue Gas Desulfurization System

1.2.2.1 Number of scrubber modules in operation.

1.2.2.2 Atomizer slurry flow rate to each scrubber module (gal per min).

1.2.2.3 Inlet and outlet temperature for each scrubber module (°F).

1.2.2.4 Pressure differential across each scrubber module (inches of water column).

1.2.2.5 Unit load (MWe).

1.2.2.6 Inlet and outlet SO_2 concentration as determined by the monitor or missing data substitution procedures.

1.2.2.7 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.3 Parameters for Other Flue Gas Desulfurization Systems

If SO_2 control technologies other than wet or dry lime or limestone scrubbing are selected for flue gas desulfurization, a corresponding empirical correlation or process simulation parametric method using appropriate parameters may be developed by the owner or operator of the affected unit, and then reviewed and approved or modified by the Administrator on a case-by-case basis.

1.2.4 Parameters for Post-Combustion NO_x Emission Controls

1.2.4.1 Inlet air flow rate to the unit (boiler) (mcf/hr).

1.2.4.2 Excess oxygen concentration of flue gas at stack outlet (percent).

1.2.4.3 Carbon monoxide concentration of flue gas at stack outlet (ppm).

1.2.4.4 Temperature of flue gas at outlet of the unit (°F).

1.2.4.5 Inlet and outlet NO_x emission rate as determined by the NO_x continuous emission monitoring system or missing data substitution procedures.

1.2.4.6 Any other parameters specific to the emission reduction process necessary to verify the NO_x control removal efficiency, (e.g., reagent feedrate in gal/mi).

emission monitoring system or missing data substitution procedures.

1.2.4.6 Any other parameters specific to the emission reduction process necessary to verify the NO_x control removal efficiency, (e.g., reagent feedrate in gal/mi).

1.3 Correlation of Emissions With Parameters

Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the SO_2 or post-combustion NO_x emission controls under varying unit operating loads. Equations 1–7 in § 75.15 of this part may be used to estimate the percent removal efficiency of the SO_2 emission controls.

Each parametric data substitution procedure should develop a data correlation procedure to verify the performance of the SO_2 emission controls or post-combustion NO_x emission controls, along with the SO_2 pollutant concentration monitor and NO_x continuous emission monitoring system values for varying unit load ranges.

For NO_x emission rate data, and wherever the performance of the emission controls varies with the load, use the load range procedure provided in section 2.2 of this appendix.

1.4 Calculations

1.4.1 Use the following equation to calculate substitute data for filling in missing (outlet) SO_2 pollutant concentration monitor data.

$M_o = I_c (1–E)$

(Eq. C–1)

where,

M_o = Substitute data for outlet SO_2 concentration, ppm.

I_c = Recorded inlet SO_2 concentration, ppm.

E = Removal efficiency of SO_2 emission controls as determined by the correlation procedure described in section 1.2 of this appendix.

1.4.2 Use the following equation to calculate substitute data for filling in missing (outlet) NO_x emission rate data.

$M_o = I_c (1–E)$

(Eq. C–2)

where,

M_o = Substitute data for outlet NO_x emission rate, lb/mmBtu.

I_c = Recorded inlet NO_x emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO_x emission controls determined by the correlation procedure described in section 1.2 of this appendix.

1.5 Missing Data

1.5.1 If both the inlet and the outlet SO_2 pollutant concentration monitors are unavailable simultaneously, use the maximum inlet SO_2 concentration recorded by the inlet SO_2 pollutant concentration monitor during the previous 720 quality assured monitor operating hours to substitute for the inlet SO_2 concentration in Equation C–1 of this appendix.

1.5.2 If both the inlet and outlet NO_x continuous emission monitoring systems are unavailable simultaneously, use the maximum inlet NO_x emission rate for the corresponding unit load recorded by the NO_x continuous emission monitoring system at the inlet during the previous 2160 quality assured monitor operating hours to substitute for the inlet NO_x emission rate in Equation C–2 of this Appendix.

1.6 Application

Apply to the Administrator for approval and certification of the parametric substitution procedure for filling in missing SO_2 concentration or NO_x emission rate data using the established criteria and information identified above. DO not use this procedure until approved by the Administrator.

2. Load-Based Procedure for Missing Flow Rate and NO_x Emission Rate Data

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow (scfh) and NO_x emission rate (in lb/mmBtu).

2.2 Procedure

2.2.1 For a single unit, establish 10 operating load ranges defined in terms of percent of the maximum integrated hourly gross load of the unit, in gross megawatts (MWge), (that is, load resulting from all combustion of fuel, including internal usage and generation for sale) as shown in Table C–1. For units sharing a common stack monitored with a single flow monitor, the load ranges for flow may be broken down into 20 equally-sized operating load ranges in increments of 5 percent of the combined maximum integrated hourly gross load of all units utilizing the common stack. For a cogenerating unit or other unit that does not produce electricity only from heat input, use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia) instead of MWge. Indicate a change in the number of load ranges or the units of loads to be used in the precertification section of the monitoring plan.

TABLE C–1.—DEFINITION OF OPERATING LOAN RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURES

Operating load range	Percent of maximum integrated hourly gross load (%)
1	0–10
2	>10–20
3	>20–30
4	>30–40
5	>40–50
6	>50–60
7	>60–70
8	>70–80
9	>80–90
10	>90–100

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x continuous emission monitoring system, for each hour of unit operation record a number, 1 through 10, (or 1 through 20 for flow at common stacks) that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO_x continuous emission monitoring system and continuing thereafter, calculate and record the following information for each unit operating hour within each identified load range during the shorter of: (1) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (2) all previous quality assured monitor operating hours.

2.2.3.1 A running average of the hourly flow rates reported by a flow monitor, in scfh, for all unit operating hours.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

2.2.3.5 A running average of the hourly NO_x emission rate, in lb/mmBtu, reported by a NO_x continuous emission monitoring system for all unit operating hours.

2.2.3.6 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO_x emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO_x emission rates, in lb/mmBtu.

2.2.4 Calculate all monitor or continuous emission monitoring system data averages, maximum values, and percentile values determined by this procedure using bias adjusted values in the load ranges.

2.2.5 When a bias adjustment is necessary for the flow monitor and/or the NO_x continuous emission monitoring system, apply the adjustment factor to all monitor or continuous emission monitoring system data averages, maximum values, and percentile values determined by the procedure.

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_x emission rate data according to the procedures in subpart D of this part.

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

1. Applicability

1.1 This procedure may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 emissions from: (1) Gas-fired units as defined in § 72.2 of this chapter; or (2) oil-fired units as defined in § 72.2 of this chapter. This optional SO_2 emissions data protocol contains two methods for conducting oil sampling and analysis in Section 2.2 of this appendix; the procedures for flow proportional oil sampling and the procedures for manual daily oil sampling may be used for any gas-fired unit or oil-fired unit.

1.2 This procedure may also be certified by the Administrator and used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 emissions from new gas-fired units or new oil-fired units provided that the new gas-fired unit or oil-fired unit is

designed to combust only oil, natural gas, or a coal-derived gaseous fuel with a sulfur content no greater than natural gas.

1.3 Apply to the Administrator for certification using this method in lieu of continuous SO_2 pollutant concentration and flow monitors no later than the deadlines for the certification of continuous emission monitoring system specified in § 75.4 of this part. Whenever the monitoring method is to be changed, reapply to the Administrator for certification of the new monitoring method.

1.4 Do not use the methods specified in this appendix for accounting for SO_2 emissions prior to obtaining certification from the Administrator.

2. Procedure

2.1 Flowmeter Measurements

When the unit is combusting oil, measure and record the flow of oil consumed on an hourly basis. Measure the flow of oil with an in-line fuel flowmeter and automatically record the data. Measure the flow of all oil entering and being combusted by the unit. Any pipe returning fuel to a pipe that provides oil to the unit (e.g. a pipe recirculating oil to the storage tank) requires an in-line fuel flowmeter.

2.1.1 Design and equip each fuel flowmeter used to meet the requirements of this protocol to demonstrate a flowmeter accuracy of 2.0 percent of the upper range value (i.e, maximum calibrated oil flow rate) as measured under laboratory conditions by the manufacturer or by the owner or operator. Use the procedures in the following ASME codes for flow measurement for use in the laboratory, as appropriate to the type of flow meter: ASME MFC–3M–1989 with September 1990 Errata (Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi), 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), or ASME 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). If the flow meter accuracy exceeds 2 percent of the upper range value, the flow meter does not qualify for certification.

2.1.2 Recalibrate each fuel flowmeter to a flowmeter accuracy of 2.0 percent of the upper range value at least annually, or more frequently if required by manufacturer specifications using the same ASME procedures required for initial calibration and certification, to meet the requirements of this protocol.

2.1.3 Alternatively, the fuel flowmeter used for the purposes of this part may be recalibrated to a flowmeter accuracy of 2.0 percent of the upper range value at least annually by comparing the measured flow of a flow meter to the measured flow from another flow meter which has been calibrated or recalibrated during the previous 365 days using the procedures in ASME MFC–9M–1988 with December 1989 Errata, "Measurement of Liquid Flow in Closed Conduits by Weighing Method", or which has been recalibrated by the manufacturer. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow readings for each meter at each of three different flow levels, corresponding to the three operating levels listed in § 6.5.2 of Appendix A of this part. Calculate the flowmeter accuracy using [Equation A–7 in Appendix A of this part, substituting the measured flow from the flow meter that is calibrated by the weighing method for the reference value.] Or the following equation:

$$ACC = \frac{|R-A|}{URV} \times 100$$

(Eq. D–1)

where,

ACC = Flow meter accuracy as a percentage of the upper range value.

R = Average of the three low-, mid-, or high-level flow measurements of the reference flow meter.

A = Average of the three measurements of the flow meter being tested.

URV = Upper range value of fuel flow meter being tested (i.e. maximum measurable flow).

If the flow meter accuracy exceeds 2% of the upper range value, either recalibrate the flow meter until the accuracy is within the performance specification, or replace the flow meter with another one that is within the performance specification.

2.2 Oil Sampling and Analysis

Perform sampling and analysis of as-fired oil to determine the percentage of sulfur by weight in the oil.

2.2.1 Perform oil sampling every day the unit is combusting oil. Use either the flow proportional method described in section 2.2.2 of this appendix or the daily manual method described in section 2.2.3 of this appendix for gas-fired units and oil-fired units.

2.2.2 Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177–82 (Reapproved 1990), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6 of this part), every day the unit is combusting oil. Extract oil at least once every hour and blend into a daily composite sample. The sample compositing period may not exceed 24 hr.

2.2.3 For a gas-fired unit or oil-fired unit, representative as-fired oil samples may be taken manually every 24 hr according to ASTM D4057–88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6 of this part), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purposes of calculating SO_2 emissions under Section 3 of this appendix.

Note: For units with pressurized fuel flow lines such as some diesel and dual-fuel reciprocating internal combustion engine units, a manual sample may be taken from the point closest to the unit where it is safe to take a sample (including back to the oil tank), rather than just prior to entry to the boiler or combustion chamber.

2.2.4 Split and label each daily oil sample. Maintain a portion (at least 200 cc) of each daily sample throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129–91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," ASTM D1552–90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D2622–92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry," or ASTM D4294–90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy" (incorporated by reference under § 75.6).

2.2.5 Where the flowmeter records volumetric flow rather than mass flow, analyze daily oil samples to determine the density or specific gravity of the oil. Determine the density or specific gravity of the oil sample in accordance with ASTM D941–88, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer," ASTM D1217–91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer," ASTM D1481–91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary," ASTM D1480–91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer," ASTM D1298–85 (Reapproved 1990), "Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method," or ASTM D4052–91, "Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter" (incorporated by reference under § 75.6).

2.2.6 Analyze daily oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240–87 (1Reapproved 1991), "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter," ASTM D1382–88, "Standard Test Method for Heat or Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method)", or ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" (incorporated by reference under § 75.6).

2.2.7 Results from the daily oil sample analysis must be available no later than thirty calendar days after the same is composited or taken. However, during an audit, the Administrator may require the results of the analysis in less than thirty calendar days.

2.3 *Missing Data Procedures.*

When data from the procedures of this part are not available, provide substitute data using the following procedures.

2.3.1 When sulfur content data from the analysis of a daily oil sample are missing or

invalid, substitute the highest measured sulfur content and oil density (if using a volumetric flowmeter) recorded during the previous 30 days when the unit burned oil.

2.3.2 When data from the fuel flowmeter are missing, substitute for each hour in the missing data period the average hourly oil flow rate measured and recorded by the fuel flowmeter at the closet unit load (in MWe) greater than the load recorded for the missing data period for which oil flow rate data are available during the previous 720 hours during which the unit combusted oil. If no oil flow rate data are available at a load greater than the load recorded during the missing data period, substitute the maximum flow rate that the flowmeter can measure.

2.4 For each hour that natural gas is combusted by the unit, account for the daily SO_2 emissions, either by (1) measuring the sulfur content of the gas using ASTM D1072–90, "Standard Test Method for Total Sulfur in Fuel Gases" (incorporated by reference under § 75.6 of this part) and the fuel usage in 100 scf or (2) using the SO_2 emission rates listed in NADB for that unit and the daily heat input from natural gas, as determined using the procedures in Appendix F of this part.

3. Calculations

Where the flowmeter records mass flow, use the calculation procedures in section 3.1, and where the flowmeter records volumetric flow, use the calculation procedures in section 3.2.

3.1 SO_2 Calculation Using Mass Flow

3.1.1 Use the following equation to calculate SO_2 mass emissions per hour (in lb/hr).

$$M_{so2}=2.0\times M_{oil}\times \%S_{oil}/100.0$$
(Eq. D–1)

where,

M_{so2}=Hourly mass of SO_2 emitted, lb/hr.
M_{oil}=Mass of oil consumed per hr, lb/hr.
$\%S_{oil}$=Percentage of sulfur by weight measured in the sample.
2.0=Ratio of lb SO_2/lb S.

3.1.2 Record the SO_2 mass emissions for each hour. Calculate and record total quarterly and annual SO_2 mass emissions by summing hourly SO_2 mass emissions for each hour during that quarter or year when the unit combusted any oil.

3.2 SO_2 Calculation Using Volumetric Flow

3.2.1 Where the flowmeter records volumetric flow rather than mass flow, calculate and record the oil mass for each hourly period using hourly oil flow measurements and the density or specific gravity of the daily oil sample.

3.2.2 Convert density, specific gravity, or API gravity of the oil sample to density of the oil sample at the sampling location's temperature using ASTM D1250–80 (Reapproved 1990), "Standard Guide for Petroleum Measurement Tables" (incorporated by reference under § 75.6 of this part).

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.5 of this appendix, use the following equation to calculate the mass of oil consumed (in lb/hr).

$$M_{oil}=V_{oil}\times D_{oil}$$
(Eq. D–2)

where,

M_{oil}=Mass of oil consumed per hr, lb/hr.
V_{oil}=Volume of oil consumed per hr, measured in scf, gal, barrels, or m^3.
D_{oil}=Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m^3.

3.2.4 Calculate the hourly heat input to the unit from oil (mmBtu) by multiplying the heat content of the daily oil sample by the hourly oil mass.

Appendix E to Part 75—Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units

1. Applicability.

1.1 Existing Unit

This NO_x emissions estimation procedure may be used in lieu of a continuous NO_x emission monitoring system (lb/mmBtu) for determining the average NO_x emission rate and hourly NO_x emission rate from gas-fired peaking units and oil-fired peaking units when these units are (1) operated with a capacity factor of 10 percent or less on the average during the previous three calendar years and (2) operated at a capacity factor of 20 percent or less in each of those three previous calendar years. If for any year a unit's operations exceed a capacity factor of 20 percent, or if a unit's operations exceed an average capacity factor of 10 percent over the most recent three calendar years, install and certify a continuous NO_x emission monitoring system no later than December 31 of the following calendar year.

1.2 New Unit

For a new gas-fired peaking unit or a new oil-fired peaking unit commencing commercial operation after November 15, 1990 where the projected capacity factor is 10 percent or less when averaged over 3 consecutive calendar years, this procedure may be certified and used in lieu of a continuous NO_x emission monitoring system. If the new gas-fired peaking unit or the new oil-fired peaking unit operating rate is greater than 20 percent in any one calendar year or greater than 10 percent on the average for any 3 consecutive calendar years, install and certify a continuous NO_x emission monitoring system on or before December 31 of the following calendar year.

1.3 Certification

1.3.1 Apply to the Administrator for certification of this optional method no later than the deadlines for the installation of continuous emission monitoring systems specified in § 75.4 of this part.

1.3.2 Do not use this optional method to record or report NO_x emissions prior to obtaining certification from the Administrator.

2. Procedure

2.1 Initial Performance Testing

Use the following procedures for measuring NO_x emission rates at different load levels; measuring unit efficiency and heat input; and plotting the correlation between operating load and NO_x emission rate or unit efficiency, in order to determine the performance and emission rate of the unit(s) prior to certification of this optional method.

2.1.1 Load Selection

Establish five approximately equally spaced operating load points, ranging from the maximum operating load to the minimum operating load. Use the unit's nameplate capacity as the maximum operating load. Select the minimum operating load from the operating history of the unit during the most recent two years. For new gas-fired peaking units or new oil-fired peaking units, select the minimum operating load from the expected minimum load to be dispatched to the unit in the first three calendar years of operation.

2.1.2 NO_x and O_2 Concentration Measurements

Use the following procedures to measure NO_x and O_2 concentration in order to determine NO_x emission rate.

2.1.2.1 Except for stationary gas turbines, measure the NO_x and O_2 concentration at 3 excess oxygen levels at each load point for each fuel or each combination of fuels to be combusted using the methods specified below in section 2.1.2.2 or 2.1.2.3 of this appendix. Establish the three excess oxygen levels as the minimum, normal, and maximum levels. Select the minimum, normal, and maximum levels at each load point according to the operating history of the unit during the most recent two years. For new gas-fired peaking units or new oil-fired peaking units, select the minimum, normal, and maximum levels at each load point per manufacturer's recommendations. For stationary gas turbines, measure the NO_x and O_2 concentration at the normal oxygen level at each load, and again at another oxygen level if the temperature of the (combustion) air at the air intake varies by more than 4°F from the average test conditions at that load.

2.1.2.2 Measure the NO_x and O_2 concentrations according to Appendix A, Method 20 of part 60 of this chapter for stationary gas turbines. Measure the NO_x and O_2 concentrations according to Method 20 for diesel or dual fuel fuel reciprocating engines, but modify Method 20 with respect to the selection of a sampling site to be as close as practical to the exhaust of the engine.

2.1.2.3 Measure the NO_x and O_2 concentrations according to Appendix A, Methods 7E of 3A of part 60 of this chapter for all other gas-fired peaking units or oil-fired peaking units.

2.1.2.4 Allow the unit to stabilize for a minimum of one hour prior to commencing NO_x, O_2, and unit efficiency measurements. Repeat the NO_x measurement two times (i.e., for a total of three times) and obtain an arithmetic average of the NO_x measurements for each of the three oxygen levels. Record the oxygen level for a period of at least 20 minutes at 5 minute intervals and report the average of all readings as the excess oxygen level for this period.

2.1.3 Heat Input

Measure the total heat input of fuel flow or a combination of fuel flows as follows:

2.1.3.1 Calibrate in-line flow meters using the procedures and specifications contained in the following ASME codes for flow measurement for use in the laboratory, as appropriate to the type of flow meter: 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–7N–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 for other flow meter types for liquids) (incorporated by reference under § 75.6 of this part), or any other standard method approved by the Administrator. Measure the total consumption of the fuels with in-line flow meters for a period of 15 minutes. Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions.

2.1.3.2 For liquid fuels, analyze daily fuel samples to determine the heat content of the fuel. Determine heat content in accordance with ASTM D240–87 (Reapproved 1991) "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter," ASTM D2382–88, "Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method)" or ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" (incorporated by reference under § 75.6 of this part). Measure the heat content of gaseous fuels according to ASTM D1826–88, "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter". Calculate the total heat input using Equation E–1 of this appendix. Record the total heat input of fuel flow or a combination of fuel flows for each excess oxygen level at each load point.

2.1.4 Unit Efficiency

Use the following procedures to measure unit efficiency.

2.1.4.1 Measure the unit efficiency of the stationary gas turbine, the diesel, or the dual fuel-reciprocating engine at the same excess oxygen levels as established in section 2.1.2.1 of this appendix at each load point for each fuel or combination of fuels to be combusted according to one of the following methods. Use the same method for subsequent periodic retesting of the initial unit efficiency correlations.

2.1.4.2 Measure the fuel consumption, the total heat input of fuel flow or combination of fuel flows to the stationary gas turbine, and the electric energy output of the stationary gas turbine for a period of 15 minutes using the procedures specified in the ASME Performance Test Code (PTC) 22–1985, Gas Turbine Power Plants (incorporated by reference under § 75.6 of this part). Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions (68°F and 29.92 inches of mercury). Measure the fuel consumption, the total heat input of fuel flow or combination of fuel flows, and the electric energy output of the diesel or dual-fuel reciprocating engine for a period of 15 minutes using the procedures specified in the ASME Performance Test Code 17–1973 (Reaffirmed 1991), Reciprocating Internal-Combustion Engines (incorporated by reference under § 75.6 of this part). Compute the unit efficiency of the reciprocating engines using Equation E–2 of this appendix.

2.1.4.3 Measure the unit efficiency of all other oil- or gas-fired units at the same excess oxygen levels as established in section 2.1.2 of this appendix using the Heat Loss Method contained in the ASME Power Test Code 4.1–1964 (Reaffirmed 1991), Steam Generating Units (incorporated by reference under § 75.6 of this part). Compute the unit efficiency of the gas-fired peaking unit or oil-fired peaking unit using Equation E–2 of this appendix.

2.1.4.4 Allow the unit to stabilize for a minimum of one hour prior to commencing NO_x, O_2, and unit efficiency measurements. Repeat the NO_x measurement two times (i.e. for a total of three times) and obtain an arithmetic average of the NO_x measurements for each of the three oxygen levels. Record the oxygen level for a period of at least 20 minutes at 5 minute intervals and report the average of all readings as the excess oxygen level for this period.

2.1.5 Tabulation of Results

Tabulate the results of each baseline correlation test for each fuel or combination of fuels, listing: time of test, duration, operating loads, F-factors, excess oxygen levels, NO_x concentrations (ppm) on a dry basis (at actual excess oxygen level), and unit efficiency. Convert the NO_x concentrations (ppm) to NO_x emission rates (to the nearest 0.01 lb/mmBtu) according to the equation E–3 or E–4, as appropriate, of this appendix.

2.1.6 Plotting of Results

Plot the tabulated results as an x-y graph for each fuel or combination of fuel to be combusted according to the following procedures.

2.1.6.1 Plot the operating load as the independent (or x) variable and the NO_x emission rates (lb/mmBtu) as the dependent (or y) variable, where three values corresponding to the three excess oxygen levels are established according to section 2.1.2.1 of this appendix for each load point. Construct the graph by drawing four straight line segments between the five load points by connecting the highest NO_x concentration at each load point.

2.1.6.2 Plot the operating load as the independent (or x) variable and the unit efficiency as the dependent (or y) variable, where three values corresponding to the three excess oxygen levels are established according to section 2.1.2.1 of this appendix for each load point. Construct the graph by drawing four straight line segments between the five load points by connecting the unit efficiency corresponding to the nominal oxygen level at each load point.

2.2 Periodic NO_x Emission Rate Testing

Retest the NO_x emission rate of the gas-fired peaking unit or the oil-fired peaking unit prior to the earlier of 3,000 unit operating hours or the 5-year anniversary and renewal of its operating permit under part 72 of this chapter.

2.3 Other Quality Assurance/Quality Control-Related NO_x Emission Rate Testing

When the operating levels of certain parameters exceed the limits specified below, retest the NO_x emission rate to re-verify the gas-fired peaking unit's or the oil-fired peaking unit's NO_x emission rate.

2.3.1 For a stationary gas turbine, redetermine the NO_x emission rate-load correlation for each fuel and combination of fuels after exceeding the manufacturer's recommended range of the following operating parameters: positioning of inlet guide vanes (i.e., degrees of rotation of inlet guide vanes), amount of air bypass used for turbine blade cooling, flow rate of steam or water injection used for NO_x emission control, exhaust temperature, compression ratio, ambient air temperature and pressure, inlet oxygen temperature and press (if stored oxygen or on-site oxygen plant is used), unit efficiency (or unit heat rate), and any other parameters specified by the unit manufacturer.

2.3.2 For a diesel or a dual-fuel reciprocating engine, redetermine the NO_x emission rate-load correlation for each fuel or combination of fuels after exceeding the manufacturer's recommended range of the following operating parameters: air intake manifold temperature, air intake manifold pressure, exhaust temperature, compression ratio, piston speed, brake mean effective pressure, supercharging, turbocharging, unit efficiency (or unit heat rate), and any other parameters specified by the unit manufacturer.

2.3.3 For all other gas-fired peaking units and oil-fired peaking units, redetermine the NO_x emission rate load correlation for each fuel and combination of fuels if any of the following occurs:

2.3.3.1 The heat input rate (mmBtu/hr) at either the maximum or the minimum operating load varies by more than 10 percent from the heat input rate at the maximum or the minimum operating load during the previous NO_x emission rate test; or

2.3.3.2 The excess oxygen level at either the maximum or the minimum operating load varies by more than 2 percentage points O_2 from the level during the maximum or minimum operating load during the previous NO_x emission rate test; or

2.3.3.3 The unit efficiency at nominal excess O_2 at either the maximum or the minimum operating load varies by more than 3 percentage points from the unit efficiency during the maximum operating load of the previous unit efficiency test, as defined using Equation E–2 of this appendix.

2.4 Procedures for Determining Hourly NO_x Emission Rate

2.4.1 Record the time (hr. and min.) and electric energy output (MWh) at the beginning of each time period, with each time period as close to one hour in duration as practical. Calculate the average operating load using equation E–8 of this appendix.

Record this average operating load to the nearest 0.1 MW as the reading for the beginning of the time period, time t. Record the next average operating load to the nearest 0.1 MW as the reading for the end of the first time period, time t+1, and so on.

2.4.2 Read the NO_x emission rate (lb/mmBtu) corresponding to the appropriate operating load, linearly interpolating to the nearest 0.1 MW and 0.01 lb/mmBtu, using the tabulated results of the baseline NO_x correlation appropriate to the fuel or fuel combination being combusted. Record the NO_x emission rate (to the nearest 0.01 lb/mmBtu) at the beginning of each time period.

2.5 Missing Data

Provide substitute data for each unit electing to use this alternative procedure whenever a valid quality-assured hour of NO_x emission rate data has not been obtained according to the procedures and specifications of section 2.4 of this appendix. For all missing data, substitute the highest NO_x emission rate tabulated during the most recent set of baseline correlation tests for any fuel or combination of fuels at the observed operating load. Maintain a record indicating which data are substitute data and the reasons for the failure to provide a valid quality-assured hour of NO_x emission rate data according to the procedures and specifications of section 2.4 of this appendix.

3. Calculations

3.1 Heat Input

Calculate the total heat input by summing over the product of fuel consumption and the measured heat control of each fuel, as in the following equation:

$$H_T = \sum_{f=1}^{n} \sum_{t=1}^{T} 10^{-6} Q_{ft} H_f t$$

(Eq. E–1)

where

H_T=total heat input of fuel flow or a combination of fuel flows over a total time of T hours, mmBtu;

10^{-6}=conversion of Btu to mmBtu;

H_f=heat content of each fuel, Btu/scf, Btu/lb, or other appropriate units;

Q_{ft}=flow rate measured for each fuel at time t (and corrected to 68°F and 29.92 inches of mercury if fuel is gaseous), scfh, lb/hr, or other appropriate units;

n=total number of fuels to be combusted;

T=total number of hours during which heat input is computed.

3.2 Unit Efficiency

Compute unit efficiency according to the following equation:

$$\eta = \frac{(100)\ (3412)\ E}{H\ 10^6}$$

(Eq. E–2)

where,

η=unit efficiency, percent;

100=factor to convert to percentage;

10^6=conversion of mmBtu to Btu;

E=total electric energy output (kilowatt-hour) for a specified interval of time, kWh;

3412=factor to convert kwh to Btu;

H=total heat input of fuel flow for the same specified interval of time as in E, mmBtu.

3.3 F-factors

Compute the F-factors for each fuel or combination of fuels to be combusted according to Appendix A, Method 19, sections 3.2.1–3.2.4 and section 3.3 of part 60 of this chapter. For a combination of fuels, use Eq. F–8 in Appendix F of this part, using the F-factors computed above for each fuel.

3.4 NO_x Emission Rate

3.4.1 Conversion from Concentration to Emission Rate

Convert the NO_x concentrations (ppm) to NO_x emission rates (to the nearest 0.01 lb/mmBtu) according to the appropriate one of the following equations:

$$E = K\ C_d\ F_d\ \frac{20.9}{20.9 - \%O2}$$

(Eq. E–3)

where,

E=NO_x emission rate, lb/mmBtu;

K=1.19×10^{-7} (lb/dscf)/ppm NO_x

C_d=NO_x concentration measured, dry basis, ppm;

F_d=dry basis F-factor computed in Section 3.3 of this appendix, dscf/mmBtu;

20.9=percentage of air that is oxygen, percent;

$\%O_2$=O_2 concentration measured, dry basis, %.

or

$$E = K\ C_w\ F_d\ \frac{20.9}{[(20.9/100)\ (100 - \%H_2O)\ - \%O_{2w}]}$$

(Eq. E–4)

where,

E=NO_x emission rate, lb/mmBtu;

K=1.19×10^{-7} (lb/dscf)/ppm NO_x

C_w=NO_x concentration measured, wet basis, ppm;

F_d=dry basis F-factor computed in Section 3.3 of this appendix, dscf/mmBtu;

20.9=percentage of air that is oxygen, percent;

$\%H_2O$=moisture content of sample gas as measured by Appendix A, Method 4, of part 60 of this chapter, percent.

$\%O_{2w}$=O_2 concentration measured, wet basis, %.

3.4.2 Quarterly Average NO_x Emission Rate

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the quarterly average NO_x emission rate according to the following equation:

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n}\ \text{(Eq. E-5)}$$

where,

E_q=NO_x emission rate averaged over a quarter, lb/mmBtu;

E_i=hourly NO_x emission rate, lb/mmBtu;

n=number of hourly rates available in the preceding quarter.

3.4.3 Annual Average NO_x Emission Rate

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the annual average NO_x emission rate according to the following:

$$E_a = \sum_{i=1}^{n} \frac{E_i}{n}\ \text{(Eq. E-6)}$$

where,

E_a=NO_x emission rate averaged over the previous calendar year, lb/mmBtu;

E_i=hourly NO_x emission rate, lb/mmBtu;

n=number of hourly NO_x emission rates available in the preceding calendar year.

3.4.4 Cumulative NO_x Emission

Report the cumulative NO_x emissions (tons) as required in subpart G of this part. Calculate the cumulative NO_x emission rate according to the following equation:

$$E_{total} = \frac{E_a H_a}{2000}\ \text{(Eq. E-7)}$$

where,

E_{total}=cumulative NO_x emissions in the previous calendar year, tons;

E_a=NO_x emission rate averaged over the previous calendar year, lb/mmBtu;

H_a=total heat input in the previous calendar year, mmBtu.

3.5 Average Operating Load

Calculate the average operating load as follows:

$$P = \frac{E_{t+1} - E_t}{T}\ \text{(Eq. E-8)}$$

where,

P=average operating load (electric), MWe;

E_t=electric energy output (megawatt-hour) reading at the beginning of the time period, time t, MWh;

E_{t+1}=electric energy output (megawatt-hour) reading at the end of the time period, time t+1, MWh;

T=the duration of the time period from t to t+1, calculated by taking the difference between t+1 and t, hr.

4. Quality Assurance/Quality Control Plan

Include a section on the NO_x emission rate determination as part of the monitoring quality assurance/quality control plan required under § 75.21 and Appendix B of this part for each gas-fired peaking unit and each oil-fired peaking unit. In this section present information including, but not limited to, the following: (1) A copy of all data and results from the initial NO_x emission rate and unit efficiency testing, including the values of quality assurance parameters specified in Section 2.3 of this appendix; (2) a copy of all data and results from the most recent NO_x emission rate load correlation and unit efficiency testing; (3) a copy of the unit manufacturer's recommended range of quality assurance- and quality control-related operating parameters.

4.1 Submit a copy of the unit manufacturer's recommended range of operating parameter values, and the range of operating parameter values recorded during the previous NO_x emission rate test and unit efficiency test that determined the unit's NO_x emission rate, along with the unit's monitoring plan.

4.2 Keep records of these operating parameters for each hour of operation in order to demonstrate that a unit is remaining within the manufacturer's recommended operating range.

Appendix F to Part 75—Conversion Procedures

1. Applicability

Use the procedures in this appendix to convert measured data from a monitor or continuous emission monitoring system into the appropriate units of the standard.

2. Procedures for SO_2 emissions

Use the following procedures to compute hourly, quarterly, and annual SO_2 mass emissions (in lb/hr). Use the procedures in Method 19 in Appendix A to part 60 of this chapter to compute hourly SO_2 emission rates (in lb/mmBtu) for qualifying Phase I technologies.

2.1 When measurements of SO_2 concentration and flow rate are on a wet basis, use the following equation to compute hourly SO_2 mass emissions (in lb/hr).

$E_h = K\ C_h\ Q_h$

(Eq. F–1)

where,

E_h=Hourly SO_2 mass emissions, lb/hr.

K=1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_h=Hourly average SO_2 concentration, stack moisture basis, ppm.

Q_h=Hourly average volumetric flow rate, stack moisture basis, scfh.

2.2 When measurements by the SO_2 pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO_2 mass emissions (in lb/hr).

$$E_h = K\ C_{hp}\ Q_{hs}\ \frac{(100-\%H_2O)}{100}$$

(Eq. F–2)

where,

E_h=Hourly SO_2 mass emissions, lb/hr.

K=1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_{hp}=Hourly average SO_2 concentration, ppm (dry).

Q_{hs}=Hourly average volumetric flow rate, scfh as measured (wet).

$\%H_2O$=Hourly average stack moisture content, percent by volume.

2.3 Use the following equations to calculate total SO_2 mass emissions for each calendar quarter (Eq. F–3) and for each calendar year (Eq. F–4) in tons.

$$E_q = \frac{\sum_{h=1}^{n} E_h}{2000}$$

(Eq. F–3)

where,

E_q=Quarterly total SO_2 mass emissions, tons.

E_h=Hourly SO_2 mass emissions, lb/hr.

n=Number of hourly SO_2 emissions values during calendar quarter.

2000=Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^{4} E_q$$

(Eq. F–4)

where,

E_a=Annual total SO_2 mass emissions, tons.

E_q=Quarterly SO_2 mass emissions, tons.

q=Quarters for which E_q are available during calendar year.

2.4 Round all SO_2 mass emissions to the number of decimal places identified in § 75.50(c) of this part (in lb/hr).

3. Procedures for NO_x Emission Rate

Use the following procedures to convert continuous emission monitoring system measurements of NO_x concentration (ppm) and diluent concentration (percentage) into NO_x emission rates (in lb/mmBtu). Perform measurements of NO_x and diluent (O_2 or CO_2) concentrations on the same moisture (wet or dry) basis.

3.1 When the NO_x continuous emission monitoring system uses O_2 as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

$$E = K\ C_h\ F\ \frac{20.9}{20.9\ -\ \%O_2}$$

(Eq. F–5)

where,

K, E, C_h, F, and $\%O_2$ are defined in section 3.3 of this appendix. When measurements are performed on a wet basis, use the equations in Method 19 in Appendix A of part 60 of this chapter.

3.2 When the NO_x continuous emission monitoring system uses CO_2 as the diluent, use the following conversion procedure:

$$E = K\ C_h\ F_c\ \frac{100}{\%CO_2}$$

(Eq. F–6)

where,

K, E, C_h, F_c, and $\%CO_2$ are defined in section 3.3 of this appendix.

3.3 Use the definitions listed below to derive values for the parameters in Equations F–5 and F–6 of this appendix.

3.3.1 K=1.19×10^{-7} (lb/dscf)/ppm NO_x.

3.3.2 E=pollutant emissions, lb/mmBtu.

3.3.3 C_h=hourly average pollutant concentration, ppm.

3.3.4 $\%O_2$, $\%CO_2$=oxygen or carbon dioxide volume (expressed as percent O_2 or CO_2).

3.3.5 F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels.

TABLE 1.—F- AND F_c-FACTORS[1]

Fuel	F-factor (dscf/mmBtu)	F_c-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–92):		
Anthracite	10,100	1,970
Bituminous and subbituminous	9,780	1,800
Lignite	9,860	1,910
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920
Wood residue	9,240	1,830

[1] Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.

3.3.6 Equations F–7a and F–7b may be used in lieu of the F or F_c factors specified in Section 3.3.5 of this appendix to calculate an F factor (dscf/mmBtu) on a dry basis or an F_c factor (scf CO_2/mmBtu) on either a dry or wet basis.

(Calculate all F- and F_c factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury.)

$$F = \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{GCV} \times 10^6$$

(Eq. F-7a)

$$F_c = \frac{321 \times 10^3 (\%C)}{GCV}$$

(Eq. F-7b)

3.3.6.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176–89, "Standard Practice for Ultimate Analysis of Coal and Coke" (solid fuels), or computed from results using ASTM D1945–91, "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" or ASTM D1946–90, "Standard Practice for Analysis of Reformed Gas by Gas Chromatography" (gaseous fuels) as applicable. (These three methods are incorporated by reference under § 75.6 of this part.)

3.3.6.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" for solid and liquid fuels, and ASTM D1826–88, "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter" for gaseous fuels, as applicable. (These two methods are incorporated by reference under § 75.6 of this part).

3.3.6.3 For affected units that combust a combination of fossil (coal, oil and gas) and nonfossil (e.g., bark, wood, residue, or refuse) fuels, the F or F_c value is subject to the Administrator's approval.

3.3.6.4 For affected units that combust combinations of fossil fuels or fossil fuels and wood residue, prorate the F or F_c factors determined by Section 3.3.5 of this appendix in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \qquad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

(Eq. F-8)

where,

X_i = Fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood).

F_i or $(F_c)_i$ = Applicable F or F_c factor for each fuel type determined in accordance with Section 3.3.5 of this appendix.

n = Number of fuels being combusted in combination.

3.4 Use the following equations to calculate the average NO_x emission rate for each calendar quarter (Eq. F-9) and the annual average emission rate for each calendar year (Eq. F-10) in lb/mmBtu.

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n}$$

(Eq. F-9)

where,

E_q = Quarterly average NO_x emission rate, lb/mmBtu.

E_i = Hourly average No_x emission rate, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^{m} \frac{E_i}{m}$$

(Eq. F-10)

where,

E_a = Annual average No_x emission rate, lb/mmBtu.

E_i = Average hourly NO_x emission rate, lb/mmBtu.

m = Number of hours for which E_i is available in preceding calendar year.

3.5 Round all NO_x emission rates to the nearest 0.01 lb/mmBtu.

4. Procedures for CO_2 Mass Emissions

Use the following procedures to convert continuous emission monitoring system measurements of CO_2 concentration (percentage) and volumetric flow rate (scfh) into CO_2 mass emissions (in tons/day) when the owner or operator uses a CO_2 continuous emission monitoring system (consisting of a CO_2 diluent gas monitor and a flow monitor) to monitor CO_2 emissions from an affected unit.

4.1 When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr).

$$E_h = K C_h Q_h$$

(Eq. F-11)

where,

E_h = Hourly CO_2 mass emissions, tons/hr.

$K = 5.7 \times 10^{-7}$ for CO_2, (tons/scf) /$\%CO_2$.

C_h = Hourly average CO_2 concentration, stack moisture basis, $\%CO_2$.

Q_h = Hourly average volumetric flow rate, stack moisture basis, scfh.

4.2 When CO_2 concentration is measured on a dry basis, use Equation F-2 to calculate the hourly CO_2 mass emissions (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf)$\%CO_2$, where E_h = hourly CO_2 mass emissions, tons/hr and C_{hp} = hourly average CO_2 concentration in flue; dry basis, $\%CO_2$.

4.3 Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation F-12 and for each calendar year (Equation F-13).

$$E_{CO_{2q}} = \sum_{i=1}^{H_R} E_{h_i}$$

(Eq. F-12)

where,

E_{co24} = Quarterly total CO_2 mass emissions, tons.

E_{hi} = Hourly CO_2 mass emissions (tons/hr).

H_R = Number of hourly CO_2 mass emsissions available during calendar quarter.

$$E_{CO_{2a}} = \sum_{q=1}^{4} E_{CO_{2q}}$$

(Eq. F-13)

where,

E_{CO2a}=Annual total CO_2 mass emissions, tons.

E_{CO2q}=Quarterly total CO_2 mass emissions, tons.

q=Quarters for which E_{CO2q} are available during calendar year.

4.3.1 Whenever a valid hour of CO_2 concentration data has not been obtained and recorded, substitute for each hour in each missing data period the average of the recorded CO_2 concentration for the hour immediately before and the hour immediately following the missing data period.

4.3.2 Whenever a valid hour of volumetric flow rate data has not been obtained and recorded, use the procedure specified in subpart D of this part to provide substitute data.

4.3.3 Whenever CO_2 mass emissions data have not been measured and recorded for a period of 72 consecutive unit operating hours or for at least 90 percent of the total unit operating hours during the calendar quarter, use the appropriate procedures in Appendix G to this part to estimate CO_2 mass emissions from the affected unit.

4.4 For an affected unit, when the owner or operator is continuously monitoring O_2 concentration (in percent by volume) of flue gases using a diluent O_2 monitor, use the equations and procedures in section 4.4.1–4.4.3 of this appendix to determine hourly CO_2 mass emissions (in tons).

4.4.1 Use appropriate F and F_c factors from section 3.3.5 of this appendix in the following equation to determine hourly average CO_2 concentration of flue gases (in percent by volume).

$$CO_{2h} = 100 \frac{F_c}{F} \frac{20.9 - O_{2h}}{20.9}$$

(Eq. F-14)

Where,

CO_{2h}=Hourly average CO_2 concentration, percent by volume, dry basis.

F, F_c=F-factor or carbon-based F_c-factor from Section 3.3.5 of this appendix.
20.9=percentage of O_2 in ambient air.
O_{2h}=Hourly average O_2 concentration, percent by volume, dry basis.Q02

4.4.2 Determine CO_2 mass emissions (in tons) from hourly average CO_2 concentration (percent by volume) using Equation F–11 and the procedures in Sections 4.1 and 4.2 of this appendix.

4.4.3 Whenever a valid hour of O_2 concentration data has not been obtained and recorded, use the procedures in Sections 4.3.1–4.3.3 of this appendix to provide substitute data for each hour of each missing data period except that the phrase "CO_2 concentration" is replaced with "O_2 concentration."

5. Procedures for Heat Input

Use the following procedures to compute heat input to an affected unit (in mmBtu/hr or mmBtu/day).

5.1 Calculate and record heat input to an affected unit on an hourly basis, except as provided below for natural gas, or for units using a common stack, the owner or operator may choose to use the provisions specified in § 75.16(e) in conjunction with the procedures provided below to apportion heat input among each unit using the common stack.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input (in mmBtu/hr).

5.2.1 When measurements of CO_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100}$$

(Eq. F–15)
where,
HI=Hourly heat input, mmBtu/hr.
Q_w=Hourly average volumetric flow rate, wet basis, scfh.
F_c=Carbon-based F-factor, listed in Section 3.3.5 of this appendix for each fuel, scf/mmBtu.
$\%CO_{2w}$=Hourly concentration of CO_2, percent CO_2 wet basis.

5.2.2 When measurements of CO_2 concentrations are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100F_c}\right]\left(\frac{\%CO_{2d}}{100}\right)$$

(Eq. F–16)
where
HI=Hourly heat input, mmBtu/hr.
Q_h=Hourly average volumetric flow rate, wet basis, scfh.
F_c=Carbon-based F-Factor, listed above in Section 3.3.5 of this appendix for each fuel, scf/mmBtu.
$\%CO_{2d}$=Hourly concentration of CO_2, $\%CO_2$ dry basis.
$\%H_2O$=Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{\left(\frac{20.9}{100}\right)(100 - \%H_2O) - \%O_{2w}]}{20.9}$$

(Eq. F–17)
where
HI=Hourly heat input, mmBtu/hr.
Q_w=Hourly average volumetric flow rate, wet basis, scfh.
F=Dry basis F-Factor, listed above in Section 3.3.5 of this appendix for each fuel, dscf/mmBtu.
$\%O_{2w}$=Hourly concentration of O_2, percent O_2 wet basis.
$\%H_2O$=Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2 concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100F}\right]\left[\frac{(20.9 - \%O_{2d})}{20.9}\right]$$

(Eq. F–18)
where,
HI=Hourly heat input, mmBtu/hr.
Q_w=Hourly average volumetric flow, wet basis, scfh.
F=Dry basis F-factor, listed above in Section 3.3.5 of this appendix for each fuel, dscf/mmBtu.
$\%H_2O$=Moisture content of the stack gas, percent.
$\%O_{2d}$=Hourly concentration of O_2, percent O_2 dry basis.

5.3 Whenever a valid hour of flow data has not been obtained and recorded, use the procedures specified in subpart D of this part to provide substitute data.

5.4 Whenever a valid hour of diluent (O_2 or CO_2) concentration data has not been obtained and recorded, substitute for each hour in each missing data period the average of the recorded diluent gas (O_2 or CO_2) percentage concentration for the hour immediately before and the hour immediately following the missing data period.

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2 emissions or for any affected unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly (or, when combusting natural gas, daily) heat input in mmBtu/hr or mmBtu/day.

5.5.1 When the unit is combusting oil, use the following equation to calculate hourly heat input.

$$HI_o = M_o \frac{GCV_o}{10^6}$$

(Eq. F–19)
where,
HI_o=Hourly heat input from oil, mmBtu/hr.
M_o=Mass of oil consumed per hour, as determined using procedures in appendix D of this part, in lb, tons, or kg.
GCV_o=Gross calorific value of oil, as measured daily by ASTM D240–87 (Reapproved 1991), ASTM D2015–91, or ASTM D2382–88, Btu/unit mass (incorporated by reference under § 75.6 of this part).
10^6=Conversion of Btu to mmBtu.

5.5.2 When the unit is combusting natural gas, use the following equation to calculate heat input from natural gas for each 24-hour period.

$HI_g = Q_g\ GCV_g$
(Eq. F–20)
where,
HI_g=Daily heat input from natural gas, mmBtu/day.
Q_g=Flow or amount of natural gas combusted during 24-hour period, million cubic feet.
GCV_g=Gross calorific value of natural gas, as verified by the contractual supplier using ASTM D1826–88, Btu/cubic foot (incorporated by reference under § 75.6 of this part).

5.5.3 When the unit is combusting coal, use the procedures, methods, and equations in sections 5.5.3.1–5.5.3.3 of this appendix to determine the heat input from coal for each 24-hour period. (All ASTM methods are incorporated by reference under § 75.6 of this part.)

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in Appendix A to part 60 of this chapter and use ASTM Method D2234–89, "Standard Test Methods for Collection of a Gross Sample of Coal," (incorporated by reference under § 75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling.

5.5.3.2 Use ASTM D2013–86, "Standard Method of Preparing Coal Samples for Analysis," for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D2015–91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter." (Both ASTM methods are incorporated by reference under § 75.6 of this part.)

On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods.

5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500}$$

(Eq. F–21)

where,

HI_c=Daily heat input from coal, mmBtu/day.

M_c=Mass of coal consumed per day, as measured and recorded in company records, tons.

GCV_c=Gross calorific value of coal sample, as measured by ASTM D3176–89, or D2015–91, Btu/lb.

500=Conversion of Btu/lb to mmBtu/ton.

6. Procedure for Converting Volumetric Flow to STP

Use the following equation to convert volumetric flow at actual temperature and pressure to standard temperature and pressure.

$$F_{STP}=F_{Actual}(T_{Std}/T_{Stack})(P_{Stack}/P_{Std})$$

(Eq. F–22)

where,

F_{STP}=Flue gas volumetric flow rate at standard temperature and pressure, scfh.

F_{Actual}=Flue gas volumetric flow rate at actual temperature and pressure, acfh.

T_{Std}=Standard temperature=68 degrees F.

T_{Stack}=Flue gas temperature at flow monitor location, degrees F.

P_{Stack}=The absolute flue gas pressure=barometric pressure at the flow monitor location + flue gas static pressure, inches of Hg.

P_{Std}=Standard pressure=29.92 inches of Hg.

Appendix G to Part 75—Determination of CO_2 Emissions

1. Applicability

The procedures in this appendix may be used to estimate CO_2 mass emissions discharged to the atmosphere (in tons/day) as the sum of CO_2 emissions from combustion and, if applicable, CO_2 emissions from sorbent used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emission controls.

2. Procedures for Estimating CO_2 Emissions From Combustion

Use the following procedures to estimate daily CO_2 mass emissions from the combustion of fossil fuels. The optional procedure in section 2.3 of this appendix may also be used for an affected gas-fired unit. For an affected unit that combusts any nonfossil fuels (e.g., bark, wood, residue, or refuse), either use a CO_2 continuous emission monitoring system or apply to the Administrator for approval of a unit-specific method for determining CO_2 emissions.

2.1 Use the following equation to calculate daily CO_2 mass emissions (in tons/day) from the combustion of fossil fuels.

$$W_{CO_2}=\frac{(MW_c+MW_{O_2})\times W_c}{2{,}000\ MW_C}$$

(Eq. G–1)

Where,

W_{co2} = CO_2 emitted from combustion, tons/day.

MW_c = Molecular weight of carbon (12.0).

W_{o2} = Molecular weight of oxygen (32.0)

W_c = Carbon burned, lb/day, determined using average weekly fuel analysis by ASTM D3178–89 for coal; or determined by the percentage of carbon in oil from the ultimate analysis of oil, or computed based upon ASTM D3238–90 and either ASTM D2502–87 or ASTM D2503–82 (Reapproved 1987) for oil; or computed based on ASTM D1945–91 or ASTM D1946–90 for gas; and weekly fuel feed rates from company records for all fuels (these six methods are incorporated by reference under § 75.6 of this chapter).

2.2 For an affected coal-fired unit, the estimate of daily CO_2 mass emissions given by Equation G–1 may be adjusted to account for carbon retained in the ash using the procedures in either section 2.21–2.23 or Section 2.24 of the appendix.

2.2.1 Determine the ash content of the weekly sample of coal using ASTM D3174–89 "Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal" (incorporated by reference under § 75.6 of this part).

2.2.2 Sample and analyze the carbon content of the fly-ash according to ASTM D3178–89, "Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke" (incorporated by reference under § 75.6 of this part).

2.2.3 Discount the estimate of daily CO_2 mass emissions from the combustion of coal given by Equation G–1 by the percent carbon retained in the ash using the following equation:

$$W_{NCO2}=W_{CO2}-\left(\frac{MW_{CO2}}{MW_c}\right)\left(\frac{A\%}{100}\right)\left(\frac{C\%}{100}\right)W_{COAL}$$

(Eq. G-2)

where,

W_{NCO2} = Net CO_2 mass emissions discharged to the atmosphere, tons/day.

W_{CO2} = Daily CO_2 mass emissions calculated by Equation G–1, tons/day.

MW_{CO2} = Molecular weight of carbon dioxide (44.0).

MW_c = Molecular weight of carbon (12.0).

A% = Ash content of the coal sample, percent by weight.

C% = Carbon content of ash, percent by weight.

W_{COAL} = Feed rate of coal from company records, tons/day.

2.2.4 The daily CO_2 mass emissions from combusting coal may be adjusted to account for carbon retained in the ash using the following equation:

$$W_{NCO2}=.99\ W_{CO2}$$

(Eq. G–3)

where,

W_{NCO2} = Net CO_2 mass emissions from the combustion of coal discharged to the atmosphere, tons/day.

.99 = Average fraction of coal converted into CO_2 upon combustion.

W_{CO2} = Daily CO_2 mass emissions from the combustion of coal calculated by Equation G–1 tons/day.

2.3 In lieu of using the procedures, methods, and equations in Section 2.1 of this appendix, the owner or operator of an affected gas-fired unit may use the following equation and records of daily gas-fired unit may use the following equation and records of daily heat input to estimate daily CO_2 mass emissions (in tons).

$$W_{CO_2}=\left(\frac{F_c\times H\times U_f\times MW_{CO_2}}{2000}\right)$$

(Eq.G–4)

where,

W_{CO2} emitted from combustion, tons/day.

F_c = Carbon-based F-factor, 1,040 scf/mmBtu for natural gas; 1,420 scf/mm/btu for crude, residual, or distillate oil.

H = Daily heat input in mmBtu, as reported in company records.

U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

3. Procedures for Estimating CO_2 Emissions From Sorbent

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use either a CO_2 continuous emission monitoring system (consisting of a CO_2 diluent gas monitor and a flow monitor) or use the procedures, methods, and equations in sections 3.1–3.2 of this appendix to determine daily CO_2 mass emissions from the sorbent (in tons).

3.1 When limestone is the sorbent material, use the equations and procedures in either section 3.1.1 or 3.1.2 of this appendix.

3.1.1 Use the following equation to estimate daily CO_2 mass emissions from sorbent (in tons).

$$SE_{CO_2}=W_{CaCO_3}\ F_u\ \frac{MW_{CO_2}}{MW_{CaCO_3}}$$

(Eq. G–5)

where,

SE_{CO2}=CO_2 emitted from sorbent, tons/day.

W_{CaCO3}=$CaCO_3$ used, tons/day.

F_u=1.00, the calcium to sulfur stoichiometric ratio.

MW_{CO2}=Molecular weight of carbon dioxide (44).

MW_{CaCO3}=Molecular weight of calcium carbonate (100).

3.1.2 In lieu of using Equation G–5, any owner or operator who operates and maintains a certified SO_2 continuous emission monitoring system (consisting of an SO_2 pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor), for measuring and recording SO_2 emission rate (in lb/mmBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations in § 75.15 of this part to estimate the SO_2 emissions removal efficiency of the emission controls, may use the following equation to estimate daily CO_2 mass emissions from sorbent (in tons).

$$SE_{CO_2} = F_u \frac{W_{SO_2}}{2000} \frac{MW_{CO_2}}{MW_{SO_2}}$$

(Eq. G–6)

where,

SE_{CO_2}=CO_2 emitted from sorbent, tons/day.

MW_{CO_2}=Molecular weight of carbon dioxide (44).

MW_{SO_2}=Molecular weight of sulfur dioxide (64).

W_{SO_2}=Sulfur dioxide removed, lb/day, based on applicable procedures, methods, and equations in § 75.15 of this part.

F_u=1.0, the calcium to sulfur stoichiometric ratio.

3.2 When a sorbent material other than limestone is used, modify the equations, methods, and procedures in Section 3.1 of this appendix as follows to estimate daily CO_2 mass emissions from sorbent (in tons).

3.2.1 Determine a site-specific value for F_u, defined as the ratio of the number of moles of CO_2 released upon capture of one mole of SO_2, using methods and procedures satisfactory to the Administrator. Use this value of F_u (instead of 1.0) in either Equation G–5 or Equation G–6.

3.2.2 When using Equation G–5, replace MW_{CaCO_3}, the molecular weight of calcium carbonate, with the molecular weight of the sorbent material that participates in the reaction to capture SO_2 and that releases CO_2, and replace W_{CaCO_3}, the amount of calcium carbonate used (in tons/day), with the amount of sorbent material used (in tons/day).

4. Procedures for Estimating Total CO_2 Emissions

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use the following equation to obtain total daily CO_2 mass emissions (in tons) as the sum of combustion-related emissions and sorbent-related emissions.

$W_t = W_{CO_2} + SE_{CO_2}$

(Eq. G–7)

where,

W_t=Estimated total CO_2 mass emissions, tons/day.

W_{CO_2}=CO_2 emitted from fuel combustion, tons/day.

SE_{CO_2}=CO_2 emitted from sorbent, tons/day.

Appendix H to Part 75—Revised Traceability Protocol No. 1

This appendix consists of section 3.0.4 of the Quality Assurance Handbook for Air Pollution Measurement Systems, Vol. 3, U.S. Environmental Protection Agency (revised 6/9/87). The Quality Assurance Handbook may be obtained from the Methods Research and Development Division, MD 78–A, Atmospheric Research Exposure and Assessment Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

3.0.4. Procedure for NBS-Traceable Certification of Compressed Gas Working Standards Used for Calibration and Audit of Continuous Source Emission Monitors (Revised Traceability Protocol No. 1)

Contents

Subsection	*Title*
3.0.4.0	General Information
3.0.4.1	*Procedure G1:* Assay and Certification of a Compressed Gas Standard Without Dilution
3.0.4.2	References

4.0 General Information

4.0.1 Purpose and Scope of the Procedure

Section 3.0.4 describes a procedure for assaying the concentration of gaseous pollutant concentration standards and certifying that the assay concentrations are traceable to an authoritative reference concentration standard. This procedure is recommended for certifying the local working concentration standards required by the pollutant monitoring regulations of 40 CFR Part 60[1,2] for the calibration and audit of continuous source emission monitors. The procedure covers certification of compressed gas (cylinder) standards for CO, CO_2, NO, NO_2, and SO_2 (Procedure G1).

4.0.2 Reference Standards

Part 60 of the monitoring regulations [1,2] require that working standards used for calibration and audit of continuous source emission monitors be traceable to either a National Bureau of Standards (NBS) gaseous Standard Reference Material (SRM or a NBS/EPA-approved Certified reference material (CRM) [3]. Accordingly, the reference standard used for assaying and certifying a working standard for these purposes must be an SRM, a CRM, or a suitable intermediate standard (see the next paragraph). SRM cylinder gas standards available from NBS are listed in Table 7.2 at the end of subsection 4.0. A current list of CRM cylinder gases and CRM vendors is available from the Quality Assurance Division (MD–77), Environmental Monitoring Systems Laboratory, U.S. EPA, Research Triangle Park, NC 27711.

The EPA regulations define a "traceable" standard as one which". . . has been compared and certified, either directly or via not more than one intermediate standard, to a primary standard such as a . . . NBS [gaseous] SRM or . . . CRM"[4,5]. Certification of a working standard directly to an SRM or CRM primary standard is, of course, preferred and recommended because of the lower error. However, an intermediate reference standard is permitted, if necessary. In particular, a *Gas Manufacturer's Intermediate Standard* (see subsection 4.0.2.1) that has been referenced directly to an SRM or a CRM according to Procedure G1 is an acceptable intermediate standard and could be used as the reference standard on that basis. However, purchasers of commercial gas standards referenced to an intermediate standard such as a GMIS should be aware that, according to the above definition, such a standard would have to be used directly for calibration or audit. Since a second intermediate standard is not permitted, such a standard could not be used as a reference standard to certify other standards.

4.0.2.1 *Gas Manufacturer's Intermediate Standard (GMIS).* A GMIS is a compressed (cylinder) gas standard that has been assayed with direct reference to an SRM or CRM and certified according to Procedure G1, and also meets the following requirements:

1. A candidate GMIS must be assayed a minimum of three (3) times, uniformly spaced over a three (3) month period.

2. Each of the three (or more) assays must be within 1.0 percent of the mean of the three (or more) assays.

3. The difference between the last assay and the first assay must not exceed 1.5 percent of the mean of the three (or more) assays.

4. The GMIS must be recertified every three months, and the reassay must be within 1.5 percent of the previous certified assay. The recertified concentration of the GMIS is the mean of the previous certified concentration and the reassay concentration.

4.0.2.2 *Recertification of Reference Standards.* Recertification requirements for SRMs and CRMs are specified by NBS and NBS/EPA, respectively. See 4.0.2.1 for GMIS recertification requirements.

4.0.3 Using the Procedure

The assay/certification procedure described here is carefully designed to minimize both systematic and random errors in the assay process. Therefore, the procedure should be carried out as closely as possible to the way it is described. Similarly, the assay apparatus has been specifically designed to minimize errors and should be configured as closely as possible to the design specified. Good laboratory practice should be observed in the selection of inert materials (e.g. Teflon, stainless steel, or glass, if possible) and clean, non-contaminating components for use in portions of the apparatus in contact with the candidate or reference gas concentrations.

4.0.4 Certification Documentation

Each assay/certification must be documented in a written certification report signed by the analyst and containing at least the following information:

1. Identification number (cylinder number).

2. Certified concentration of the standard, in ppm or mole percent.

3. Balance gas in the standard mixture.

4. Cylinder pressure at certification.

5. Date of the assay/certification.

6. Certification expiration date (see 4.0.6.3).

7. Identification of the reference standard used: SRM number, cylinder number, and concentration for an SRM; cylinder number and concentration for a CRM or GMIS.

8. Statement that the assay/certification was performed according to this section 3.0.4.

9. Identification of the laboratory where the standard was certified and the analyst who performed the certification.

10. Identification of the gas analyzer used for the certification, including the make, model, serial number, the measurement principle, and the date of the last multipoint calibration.

11. All analyzer readings used during the assay/certification and the calculations used to obtain the reported certified value.

12. Chronological record of all certifications for the standard.

Certification concentrations should be reported to 3 significant digits. Certification documentation should be maintained for at least 3 years.

4.0.5 Certification Label

A label or tag bearing the information described in items 1 through 9 of subsection 4.0.4 must be attached to each certified gas cylinder.

4.0.6 Assay/Certification of Compressed Gas (Cylinder) Standards

4.0.6.1 *Aging of newly-prepared gas standards.* Freshly prepared gas standard concentrations and newly filled gas cylinders must be aged before being assayed and certified. SO_2 concentrations contained in steel cylinders must be aged at least 15 days; other standards must be aged at least 4 days.

4.0.6.2 *Stability test for reactive gas standards.* Reactive gas standards, including nitric oxide (NO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and carbon monoxide (CO), that have not been previously certified must be tested for stability as follows: Reassay the concentration at least 7 days after the first assay and compare the two assays. If the second assay differs from the first assay by 1.5% or less, the cylinder may be considered stable, and the mean of the two assays should be reported as the certified concentration. Otherwise, age the cylinder for a week or more and repeat the test, using the second and third assays as if they were the first and second assays. Cylinders that are not stable may not be sold and/or used for calibration or audit purposes.

4.0.6.3 *Recertification of compressed gas standards.* Compressed gas standards must be recertified according to this section 3.0.4 within the time limits specified in Table 7.1[3,6,7]. The reassay concentration must be within 5% of the previous certified concentration. If not, the cylinder must be retested for stability (subsection 4.0.6.2). The certified concentration of a recertified standard should be reported as the mean of all assays, unless a clear trend or substantial change suggests that previous assays are no longer valid.

TABLE 7.1.—RECERTIFICATION LIMITS FOR COMPRESSED GAS STANDARDS

Pollutant	Balance gas	Concentration range	Maximum months until recertification for cylinder material	
			Al or SS	Other
Carbon monoxide	N_2 or air	≥ 5 ppm	18	6
Nitric oxide	N_2	≥ 10 ppm	18	6
Sulfur dioxide	N_2	≥ 10 ppm	18	6
Nitrogen dioxide	N_2 or air	≥ 10 ppm	6	6
Carbon dioxide	N_2 or air	≥ 300 ppm	18	18
Oxygen	N_2	≥ 2 percent	18	18
Sulfur dioxide and carbon dioxide	N_2	≥ 200 ppm SO_2, 10 percent CO_2	18	6
Propane	N_2 or air	≥ 5 ppm	18	6
Others not specifically listed			6	6

4.0.6.4 *Minimum cylinder pressure.* No compressed gas cylinder standard should be used when its gas pressure is below 700 kPa (100 psi), as indicated by the cylinder pressure gauge.

4.0.6.5 *Assay/certification of multi-component compressed gas standards.* Procedure G1 may be used to assay and certify individual components of multi-component gas standards, provided that none of the components other than the component being assayed cause a detectable response on the analyzer.

4.0.7 Analyzer Calibration

4.0.7.1 *Basic analyzer calibration requirements.* The assay procedure described in this section 3.0.4 employs a direct ratio referencing technique that inherently corrects for minor analyzer calibration variations (drift) and DOES NOT depend on the absolute accuracy of the analyzer calibration. What is required of the analyzer is as follows: 1) it must have a *linear* response to the pollutant of interest (see subsection 4.0.7.5), 2) it must have good resolution and low noise, 3) its response calibration must be reasonably stable during the assay/certification process, and 4) all assay concentration measurements must fall within the calibrated response range of the analyzer.

4.0.7.2 *Analyzer multipoint calibration.* The gas analyzer used for the assay/certification must have had a multipoint calibration within 3 months of its use when used with this procedure. This calibration is *not* used to quantitatively interpret analyzer readings during the assay/certification of the candidate gas because a more accurate, direct ratio comparison of the candidate concentration to the reference standard concentration is used. However, this multipoint calibration is necessary to establish the calibrated range of the analyzer and its response linearity.

The multipoint calibration should consist of analyzer responses to at least 5 concentrations, including zero, approximately evenly spaced over the concentration range. Analyzer response units may be volts, millivolts, percent of scale, or other measurable analyzer response units. The upper range limit of the calibrated range is determined by the highest calibration point used. If the analyzer has a choice of concentration ranges, the optimum range for the procedure should be selected and calibrated. Plot the calibration points and compute the linear regression slope and intercept. See subsection 4.0.7.5 for linearity requirements and the use of a mathematical transformation, if needed. The intercept should be less than 1 percent of the upper concentration range limit, and the correlation coefficient (r) should be at least 0.999.

4.0.7.3 *Zero and span check and adjustment.* On each day that the analyzer will be used for assay/certification, its response calibration must be checked with a zero and at least one span concentration near the upper concentration range limit. If necessary, the zero and span controls of the analyzer should be adjusted so that the analyzer's response (i.e. calibration slope) is within about ±5 percent of the response indicated by the most recent multipoint calibration. If a zero or span adjustment is made, allow the analyzer to stabilize for at least an hour or more before beginning the assay procedure, since some analyzers drift for a period of time following zero or span adjustment. If the analyzer is not in continuous operation, turn it on and allow it to stabilize for at least 12 hours before the zero and span check.

4.0.7.4 *Pollutant standard for multipoint calibration and zero and span adjustment.* The pollutant standard or standards used for multipoint calibration or zero and span checks or adjustments must be obtained from a compressed gas standard certified traceable to an NBS SRM or a NBS/EPA CRM according to Procedure G1 of this section 3.0.4. This standard need not be the same as the reference standard used in the assay/certification. The zero gas must meet the requirements in subsection 4.0.8.

4.0.7.5 *Linearity of analyzer response.* The direct ratio assay technique used in Procedure G1 requires that the analyzer have a linear response to concentration. Linearity is determined by comparing the quantitative difference between a smoothly-drawn calibration curve based on all calibration points and a straight line drawn between zero and an upper reference point (see Figure 1). This difference is measured in concentration units, parallel to the concentration axis, from a point on the calibration curve to the corresponding point for the same response on the straight line.

For the general linearity requirement, the straight line is drawn between zero and the highest calibration point (Figure 1a). Linearity is then acceptable when no point on the smooth calibration curve deviates from the straight line by more than 1.5

percent of the value of the highest calibration concentration. An alternative linearity requirement is defined on the basis of the actual reference and candidate concentrations to be used for the assay. In this case, the reference and candidate concentrations are plotted on the calibration curve, and the straight line is drawn from zero to the reference concentration and extrapolated, if necessary, beyond the candidate concentration (Figure 1b). The deviation of the smooth calibration curve from the straight line at the candidate concentration point then must not exceed 0.8 percent of the value of the reference concentration. This latter specification may allow the use of an analyzer having greater nonlinearity when the reference and candidate concentrations are nearly the same.

For analyzers having an inherently non-linear response, the response can usually be linearized with a simple mathematical transformation of the response values, such as R'=square root(R) or R'=log(R), where R' is the transformed response value and R is the actual analyzer response value. Using the transformed response values, the multipoint calibration should meet one of the above linearity requirements as well as the requirements for intercept and correlation coefficient given in subsection 4.0.7.2.

4.0.8 Zero Gas

Zero gas used for dilution of any candidate or reference standard should be clean, dry, zero-grade air or nitrogen containing a concentration of the pollutant of interest equivalent to less than 0.5 percent of the analyzer's upper range limit concentration. The zero gas also should contain no contaminant that causes a detectable response on the analyzer or that suppresses or enhances the analyzer's response to the pollutant. The oxygen content of zero air should be the same as that of ambient air.

4.0.9 Accuracy Assessment of Commercially Available Standards

Periodically, the USEPA will assess the accuracy of commercially available compressed gas standards that have been assayed and certified according to this section 3.0.4. Accuracy will be assessed by EPA audit analysis of representative actual commercial standards obtained via an anonymous agent. The accuracy audit results, identifying the actual gas manufacturers or vendors, will be published as public information.

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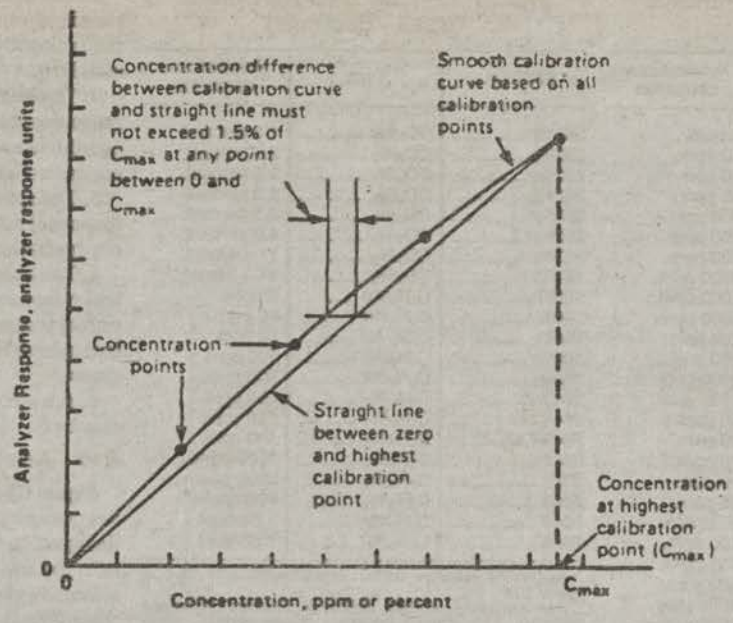
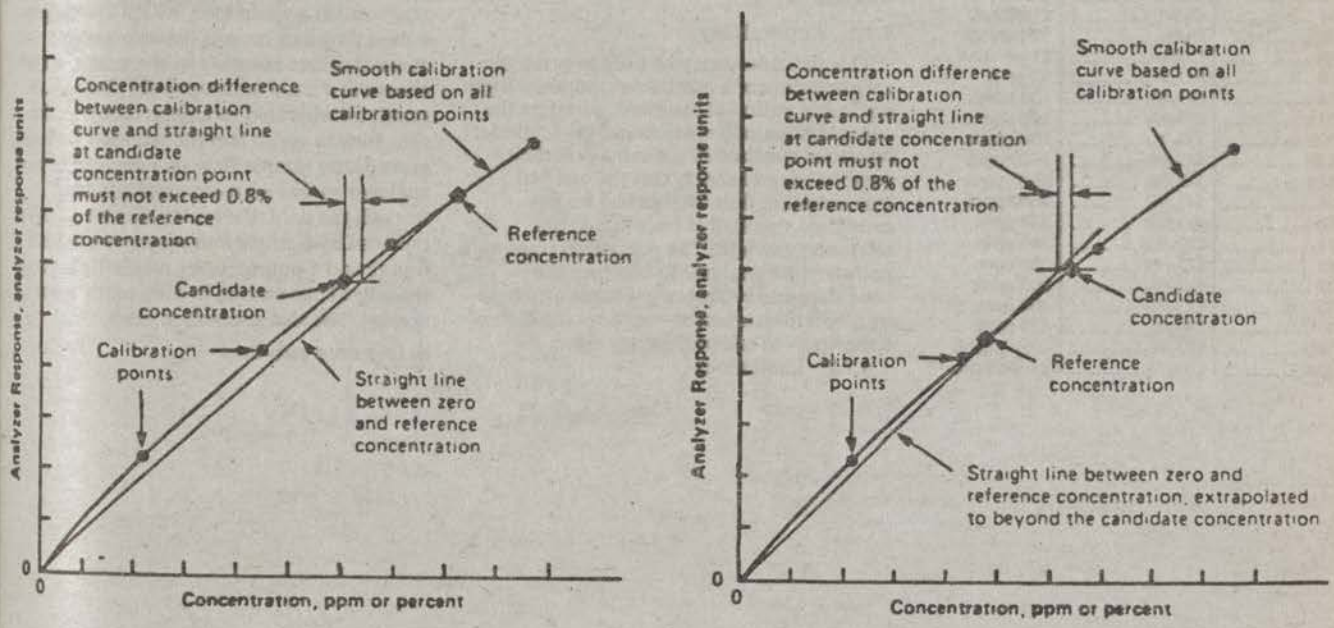


a) General linearity requirement



b) Alternative linearity requirement

Figure 1. Illustration of linearity requirements.

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TABLE 7.2.—NBS SRM REFERENCE GASES

SRM No.	Type	Nominal concentration
2627	NO/N_2	5 ppm.
2628	NO/N_2	10 ppm.
2629	NO/N_2	20 ppm.
1683b	NO/N_2	50 ppm.
1684b	NO/N_2	100 ppm.
1685b	NO/N_2	250 ppm.
1686b	NO/N_2	500 ppm.
1687b	NO/N_2	1000 ppm.
2630	NO/N_2	1500 ppm.
2631	NO/N_2	3000 ppm.
2653	$NO/_2$Air	250 ppm.
2654	$NO/_2$Air	500 ppm.
2655	$NO/_2$Air	1000 ppm.
2656	$NO/_2$Air	2500 ppm.
2612a	CO/Air	10 ppm.
2613a	CO/Air	20 ppm.
2614a	CO/Air	45 ppm.
1677c	CO/N_2	10 ppm.
2635	CO/N_2	25 ppm.
1678c	CO/N_2	50 ppm.
1679c	CO/N_2	100 ppm.
2636	CO/N_2	250 ppm.
1680c	CO/N_2	500 ppm.
1681c	CO/N_2	1000 ppm.
2637	CO/N_2	2500 ppm.
2638	CO/N_2	5000 ppm.
2639	CO/N_2	1 percent.
2640	CO/N_2	2 percent.
2641	CO/N_2	4 percent.
2642	CO/N_2	8 percent.
2657	O_2/N_2	2 percent.
2658	O_2/N_2	10 percent.
2659	O_2/N_2	21 percent.
1693	SO_2/N_2	50 ppm.
1694	SO_2/N_2	100 ppm.
1661a	SO_2/N_2	500 ppm.
1662a	SO_2/N_2	1000 ppm.
1663a	SO_2/N_2	1500 ppm.
1664a	SO_2/N_2	2500 ppm.
1696	SO_2/N_2	3500 ppm.
1670	CO_2/Air	330 ppm.
1671	CO_2/Air	340 ppm.
1672	CO_2/Air	350 ppm.
2632	CO_2/N_2	300 ppm.
2633	CO_2/N_2	400 ppm.
2634	CO_2/N_2	800 ppm.
2619a	CO_2/N_2	0.5 percent.
2720a	CO_2/N_2	1.0 percent.

TABLE 7.2.—NBS SRM REFERENCE GASES—Continued

SRM No.	Type	Nominal concentration
2621a	CO_2/N_2	1.5 percent.
2622a	CO_2/N_2	2.0 percent.
2623a	CO_2/N_2	2.5 percent.
2624a	CO_2/N_2	3.0 percent.
2625a	CO_2/N_2	3.5 percent.
2626a	CO_2/N_2	4.0 percent.
1674b	CO_2/N_2	7.0 percent.
1675b	CO_2/N_2	14.0 percent.
1665b	C_3H_8/Air	3 ppm.
1666b	C_3H_8/Air	10 ppm.
1667b	C_3H_8/Air	50 ppm.
1668b	C_3H_8/Air	100 ppm.
1669b	C_3H_8/Air	500 ppm.
2643	C_3H_8/N_2	100 ppm.
2644	C_3H_8/N_2	250 ppm.
2645	C_3H_8/N_2	500 ppm.
2646	C_3H_8/N_2	1000 ppm.
2647	C_3H_8/N_2	2500 ppm.
2648	C_3H_8/N_2	5000 ppm.
2649	C_3H_8/N_2	1 percent.
2650	C_3H_8/N_2	2 percent.

NBS–SRM cylinders contain approximately 870 liters of gas at STP.

For availability, contact: Office of Standard Reference Materials, Chemistry Building, Room B311, NBS, Gaithersburg, Maryland 20899, (301) 975–6776. (FTS 879–6776).

4.1 *Procedure G1:* Assay and Certification of a Compressed Gas Standard Without Dilution

4.1.1 Applicability

This procedure may be used to assay the concentration of a candidate compressed gas (cylinder) pollutant standard, based on the concentration of a compressed gas (cylinder) reference standard of the same pollutant compound, and certify that the assayed concentration thus established for the candidate standard is traceable to the reference standard. The procedure employs a pollutant gas analyzer to compare the candidate and reference gas concentrations by direct measurement—without dilution of either gas—to minimize assay error.

4.1.2 Limitations

1. The concentration of the candidate gas standard must be between 0.3. and 1.3 times the concentration of the reference gas standard.

2. The analyzer must have a calibrated range capable of directly measuring both the candidate and the reference gas concentrations.

3. The analyzer's response (or transformed response) must be linear with respect to concentration.

4. The balance gas in both the candidate and reference standards must be identical, unless it can be shown that the analyzer is insensitive to any difference in the balance gases.

5. A source of clean, dry zero gas is required.

4.1.3 Assay Apparatus

Figure G1 illustrates the relatively simple assay apparatus. The configuration is designed to allow convenient routing of the zero gas and undiluted samples of the reference gas and candidate gases, in turn, to the analyzer for measurement, as selected by three-way valves V1 and V2. Pressure regulators and needle valves (V3 and V4) control the individual gas flows. The pollutant concentrations are delivered to the analyzer via a vented tee, which discharges excess flow and insures that the assay concentrations sampled by the analyzer are always at a fixed (atmospheric) pressure. A small, uncalibrated rotameter monitors the vent flow to verify that the total gas flow rate exceeds the sample flow rate demand of the analyzer so that no room air is admitted through the vent. Valves V1 and V2 could be replaced by a single four-way valve (with 3 inputs and 1 output) or by manually moving the output connection to each of the gases as needed. See also subsection 4.0.3.

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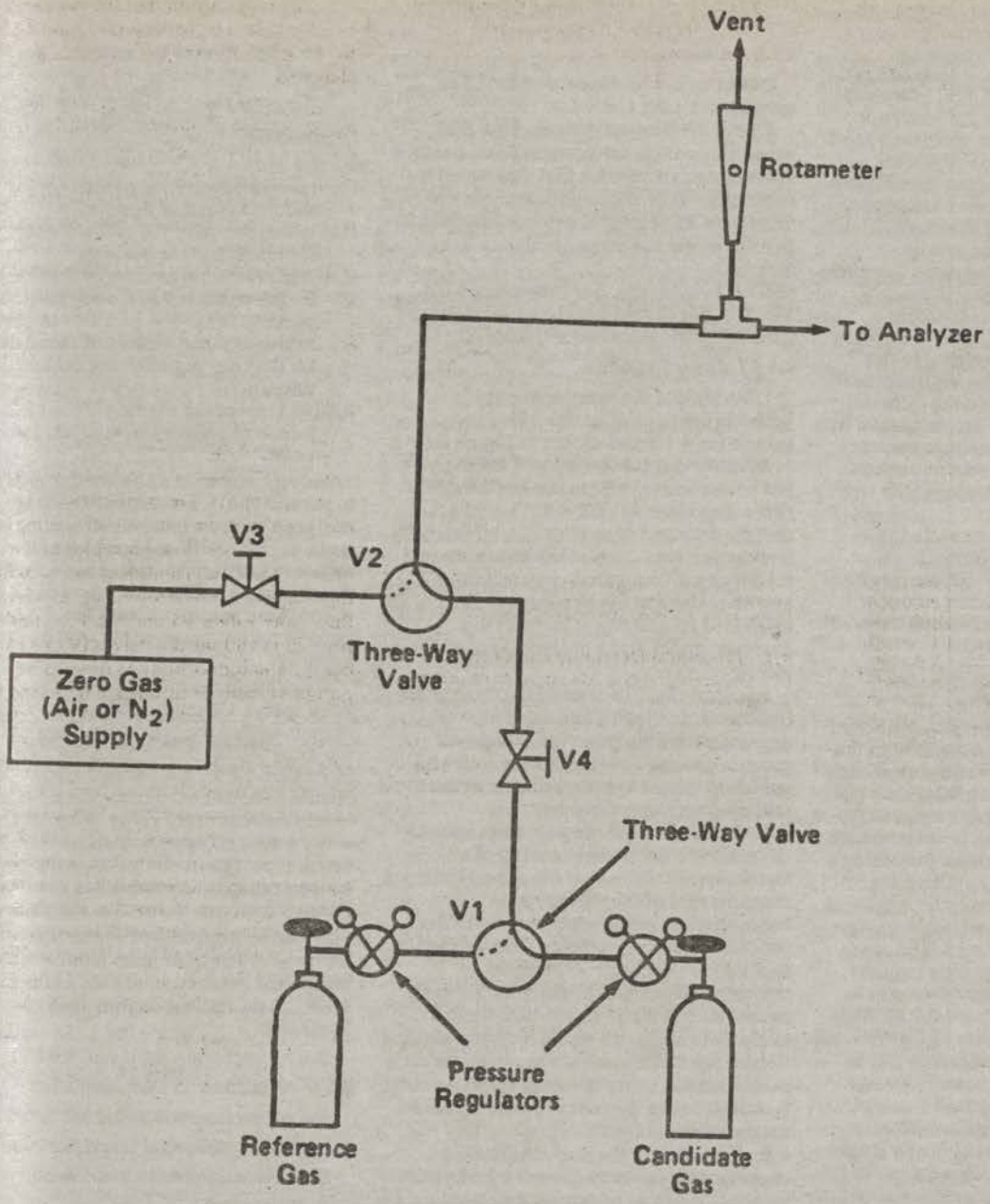

Figure G1. Suggested assay apparatus for Procedure G1.

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4.1.4 Analyzer

See subsection 4.0.7.1. The pollutant gas analyzer must have a linear response function and a calibrated range capable of measuring the full concentration of both the candidate and the reference gas standards directly, without dilution. It must have good resolution (readability), good precision, a stable response, and low output signal noise. In addition, the analyzer must have good specificity for the pollutant of interest so that it has no detectable response to any contaminant that may be contained in either the candidate or reference gas. If the candidate and reference gases contain dissimilar balance gases (air versus nitrogen or different proportions of oxygen in the balance air, for example), the analyzer must be proven to be insensitive to the different balance gases. This may be accomplished by showing no difference in analyzer response when measuring pollutant concentrations diluted with identical flow rates of the two balance gases.

The analyzer should be connected to a suitable, precision chart recorder or other data acquisition device to facilitate graphical observation and documentation of the analyzer responses obtained during the assay.

4.1.5 Analyzer Calibration

4.1.5.1 *Multipoint calibration.* See subsections 4.0.7.2 and 4.0.7.4.

4.1.5.2 *Calibration range.* The calibrated range of the analyzer must include both the candidate and reference gas concentrations, such that the higher concentration does not exceed 97 percent of the upper range limit, and the lower concentration is not below 25 percent of the upper range limit (assuming a lower range limit of zero). Within these limits, select a calibrated analyzer range that will produce the highest analyzer responses.

4.1.5.3 *Linearity.* The direct ratio assay technique used in this procedure requires that the analyzer have a linear response to concentration (see subsection 4.0.7.5). High-concentration-range analyzers of the type that are required for this procedure may not be inherently linear, but they usually have a predictable, non-linear response characteristic that can be mathematically transformed to produce a sufficiently linear response characteristic suitable for use in this procedure. Any such response transformation should be verified by using it for the multipoint calibration. Caution should be exercised in using a transformed response curve because physical zero or span adjustments to the analyzer may produce unexpected effects on the transformed characteristic.

4.1.5.4 *Zero and span adjustment.* See subsections 4.0.7.3 and 4.0.7.4. Prior to carrying out the assay/certification procedure, check the calibration of the analyzer and, if necessary, adjust the analyzer's zero and span controls to reestablish the response characteristic determined at the most recent multipoint calibration. Allow the analyzer to stabilize for an hour or more after any zero or span adjustment. If there is any doubt that a transformed response characteristic is still linear following a zero or span adjustment, verify linearity with a multipoint calibration (subsection 4.0.7.2) using at least 3 known pollutant concentrations, including zero.

4.1.6 Assay Gases

4.1.6.1 *Candidate gas standard.* See subsections 4.0.6 and 4.1.2.

4.1.6.2 *Reference gas standard.* See subsections 4.0.2, 4.1.2, and 4.0.6.4. Select a reference standard such that the concentration of the candidate gas is not more than 30 percent above nor less than 70 percent below the concentration of the standard.

4.1.6.3 *Zero gas.* See subsection 4.0.8. The zero gas should match the balance gas used in the cylinder concentrations.

4.1.7 Assay Procedure

1. Verify that the assay apparatus is properly configured, as described in subsection 4.1.3 and shown in Figure G1.

2. Verify that the linearity of the analyzer has been checked within the last 3 months (see subsections 4.0.7.2, 4.0.7.5, and 4.1.4), that the zero and span are adjusted correctly (subsection 4.0.7.3), that the candidate and reference gas concentrations are within 25 and 97 percent of the upper range limit of the calibrated measurement range of the analyzer, and that the analyzer is operating stably.

3. Adjust the flow rates of the three gases (reference, candidate, and zero) to approximately the same value that will provide enough flow for the analyzer and sufficient excess to assure that no ambient air will be drawn into the vent.

4. Conduct a triad of measurements with the analyzer. Each triad consists of a measurement of the zero gas concentration, a measurement of the reference gas concentration, and a measurement of the candidate gas concentration. Use valves V1 and V2 to select each of the three concentrations for measurement. For each measurement, allow ample time for the analyzer to achieve a stable response reading. Record the stable analyzer response for each measurement, using the same response units (volt, millivolts, percent of scale, etc.) used for the multipoint calibration and any transformation of the response readings necessary for linearity. Do not translate the response readings to concentration values via the calibration curve (see the footnote following Equation G1). Do not make any zero, span, or other physical adjustments to the analyzer during the triad of measurements.

5. Conduct at least 2 additional measurement triads, similar to step 4 above. However, for these subsequent triads, change the order of the three measurements (e.g. measure reference gas, zero gas, candidate gas for the second triad and zero gas, candidate gas, reference gas for the third triad, etc.).

6. If any one or more of the measurements of a triad is invalid or abnormal for any reason, discard all three measurements of the triad and repeat the triad.

7. For each triad of measurements, calculate the assay concentration of the candidate gas as follows:

$$C_c = C_r \frac{R_c - R_z}{R_r - R_z}$$

Equation G1

where:

C_c=Assay concentration of the candidate gas standard, ppm or percent;

C_r=Concentration of the reference gas standard, ppm or percent;

R_c=Stable response reading of the analyzer for the candidate gas, analyzer response units;*

R_z=Stable response reading of the analyzer for the zero gas, analyzer response units;*

R_r=Stable response reading of the analyzer for the reference gas, analyzer response units.*

*Analyzer response units are the units used to express the *direct* response readings of the analyzer, such as volts, millivolts, percent of scale, etc. DO NOT convert these direct response readings to concentration units with the multipoint calibration curve or otherwise adjust these readings except for transformation necessary to achieve response linearity.

8. Calculate the mean of the 3 (or more) valid assays. Calculate the percent difference of each assay from the mean. If any one of the assay values differs from the mean by more than 1.5%, discard that assay value and conduct another triad of measurements to obtain another assay value. When at least 3 assay values all agree within 1.5% of their mean, report the mean value as the certified concentration of the candidate gas standard. For newly-prepared reactive standards, a reassay at least 7 days later is required to check the stability of the standard; see subsection 4.0.6.2.

4.1.8 Stability Test for Newly-Prepared Standards

See subsections 4.0.6.1 and 4.0.6.2.

4.1.9 Certification Documentation

See subsections 4.0.4 and 4.0.5.

4.1.10 Recertification Requirements

See subsections 4.0.6.3 and 4.0.6.4.

4.2 References

1. *Code of Federal Regulations*, Title 40, part 60, "Standards of Performance for New Stationary Sources," Appendix A, Method 20 (1982).

2. Standards of Performance for New Stationary Sources; Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems Used for Compliance Determination, promulgated in the **Federal Register**, June 4, 1987, pp. 21003–21010.

3. "A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials. EPA–600/7–81–010. Joint publication by NBS and EPA, May 1981. Available from the U.S. Environmental Protection Agency, Environmental Monitoring Systems Laboratory (MD–77), Research Triangle Park, NC 27711.

4. *Code of Federal Regulation*, Title 40, part 50, "National Ambient Air Quality Measurement Methodology".

5. *Code of Federal Regulations*, Title 40, part 58, "Ambient Air Quality Surveillance," Appendixes A and B.

6. Shores, R.C. and F. Smith, "Stability Evaluation of Sulfur Dioxide, Nitric Oxide, and Carbon Monoxide Gases in Cylinders. NTIS No. PB 85–122646. Available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161.

7. Method 6A and 6B, "Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions from Fossil Fuel Combustion Sources," *Quality Assurance Handbook for Air Pollution Measurement Systems*, Volume III, Section 3.13.8, July 1986. Available from the U.S. Environmental Protection Agency, Center for Environmental Research Information, Cincinnati, OH 45268.

8. "List of Designated Reference and Equivalent Methods." Current edition available from the U.S. Environmental Protection Agency, Environmental Monitoring Systems Laboratory, Quality Assurance Division (MD–77), Research Triangle Park, NC 27711.

Appendix I of Part 75

[This appendix is reserved.]

7. Title 40 is amended by adding part 77 to read as follows:

PART 77—EXCESS EMISSIONS

Sec.

77.1 Purpose and scope.
77.2 General.
77.3 Offset plans for excess emissions of sulfur dioxide.
77.4 Administrator's action on proposed offset plans.
77.5 Deduction of allowances to offset excess emissions of sulfur dioxide.
77.6 Penalties for excess emissions of sulfur dioxide and nitrogen oxides.

Authority: 42 U.S.C. 7651j.

PART 77—EXCESS EMISSIONS

§77.1 Purpose and scope.

(a) This part sets forth the excess emissions offset planning and offset penalty requirements under section 411 of the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law 101–549 (November 15, 1990). These requirements shall apply to the owners and operators and, to the extent applicable, the designated representative of each affected unit and affected source under the Acid Rain Program.

(b) Nothing in this part shall limit or otherwise affect the application of sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Act, as amended. Any allowance deduction, excess emission penalty, or interest required under this part shall not affect the liability of the affected unit's and affected source's owners and operators for any additional fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Act.

§77.2 General.

Part 72 of this chapter, including §§ 72.2 (definitions), 72.3 (measurements, abbreviations, and acronyms), 72.4 (federal authority), 72.5 (State authority), 72.6 (applicability), 72.7 (new units exemption), 72.8 (retired units exemption), 72.9 (standard requirements), 72.10 (availability of information), and 72.11 (computation of time), shall apply to this part. The procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§77.3 Offset plans for excess emissions of sulfur dioxide.

(a) *Applicability.* The owners and operators of any affected unit that has excess emissions of sulfur dioxide in any calendar year shall be liable to offset the amount of such excess emissions by an equal amount of allowances from the unit's Allowance Tracking System account.

(b) *Deadline.* Not later than 60 days after the end of any calendar year during which an affected unit had excess emissions of sulfur dioxide (except for any increase in excess emissions under § 72.91(b) of this chapter), the designated representative for the unit shall submit to the Administrator a complete proposed offset plan to offset those emissions. Each day after the 60-day deadline that the designated representative fails to submit a complete proposed offset plan shall be a separate violation of this part.

(c) *Number of Plans.* The designated representative shall submit a proposed offset plan for each affected unit with excess emissions of sulfur dioxide.

(d) *Contents of Plan.* A complete proposed offset plan shall include the following elements in a format prescribed by the Administrator for the unit and for the calendar year for which the plan is submitted:

(1) Identification of the unit.

(2) If the unit had excess emissions for the calendar year prior to the year for which the plan is submitted, an explanation of how and why the excess emissions occurred for the year for which the plan is submitted and a description of any measures that were or will be taken to prevent excess emissions in the future.

(3) The amount of excess emissions of sulfur dioxide (in tons/year) for the year for which the plan is submitted and the number of allowances required to be deducted from the unit's Allowance Tracking System account to offset the excess emissions.

(4) At the designated representative's option, the serial numbers of the allowances that are to be deducted from the unit's Allowance Tracking System account.

(5) Whether the allowances are to be deducted immediately from the unit's account or, if not, the date on which they are to be deducted.

(6) If the proposed offset plan does not propose a deduction of the amount of allowances under paragraph (d)(3) of this section from the compliance subaccount during the year after the year for which the plan is submitted, a demonstration that such a deduction will interfere with electric reliability.

§77.4 Administrator's action on proposed offset plans.

(a) *Determination of Completeness.* The Administrator will determine whether the proposed offset plan is complete within 30 days of receipt by the Administrator. The offset plan shall be deemed complete if the Administrator fails to notify the designated representative to the contrary within 30 days of receipt or when the Administrator approves the offset plan and deducts allowances in accordance with paragraph (b)(1) of this section.

(b) *Review of proposed offset plans.* (1) If the designated representative submits a complete proposed offset plan for immediate deduction, from the unit's compliance subaccount, of all allowances required to offset excess emissions of sulfur dioxide, the Administrator will approve the proposed offset plan without further review and will serve written notice of any approval on the designated representative and on any persons entitled to written notice under paragraphs (g)(2)(i) (B), (C) and (D) of this section. The Administrator will also give notice of any approval in the **Federal Register**. The plan will be incorporated into the unit's Acid Rain permit in accordance with § 72.84 (automatic permit amendment) and will not be subject to the requirements of paragraphs (d) through (k) of this section.

(2) Notwithstanding paragraph (b)(1) of this section, the Administrator may, in his or her discretion, require that the proposed offset plan under paragraph (b)(1) of this section be reviewed under paragraphs (c) through (k) of this section. The Administrator may exercise such discretion where he or she determines that review of the plan is necessary to ensure compliance with the

emissions limitation and reduction goals or other purposes of title IV of the Act.

(3) If the designated representative submits a complete proposed offset plan that does not meet the requirements of paragraph (b)(1) of this section, the Administrator will review the plan under paragraphs (c) through (k) of this section.

(c) *Supplemental Information.* (1)(i) Regardless of whether the proposed offset plan is complete under paragraph (a) of this section, the Administrator may require submission of any additional information that the Administrator determines is necessary to approve an offset plan.

(ii) Such supplemental information may include, but is not limited to:

(A) A description of the measures that are proposed to be taken to ensure that the unit will have sufficient allowances to offset the excess emissions and to prevent excess emissions in future years;

(B) A schedule of compliance with appropriate increments of progress for the proposed measures; and

(C) A schedule for the submission of progress reports, and supporting documentation, describing actions taken and actions remaining to be taken under the schedule of compliance and any proposed adjustments to the schedule of compliance.

(2)(i) The designated representative shall submit the information required under paragraph (c)(1) of this section within 30 days after he or she is notified of the requirement for supplemental information unless the Administrator allows for additional time to collect and submit the information.

(ii) If the designated representative fails to submit the supplemental information within the required time period, the Administrator may disapprove the proposed offset plan.

(d) *Draft Offset Plan.* (1) After the Administrator receives a complete proposed offset plan and any supplemental information, the Administrator will prepare a draft offset plan that incorporates in whole, in part, or with changes or conditions as appropriate, the proposed offset plan or disapprove a draft offset plan for the affected unit. Regardless of whether the Administrator required the submission of the information set forth in paragraph (c)(1)(ii) of this section, the draft offset plan may include, among other requirements and conditions as determined to be appropriate by the Administrator, the submission of schedules of compliance, progress reports, and monitoring and other information.

(2) The draft offset plan will be based on the information submitted by the designated representative for the affected unit and other relevant information.

(3) The Administrator will serve a copy of the draft offset plan and the statement of basis on the designated representative of the affected unit.

(4) The Administrator will provide a 30-day period for public comment, and opportunity to request a public hearing, on the draft offset plan or disapproval of a draft offset plan in accordance with the public notice required under paragraph (g)(1)(i)(A) of this section.

(e) *Offset Plan Administrative Record.* (1) The Administrator will prepare an administrative record for an offset plan or disapproval of an offset plan. The administrative record will contain:

(i) The proposed offset plan and any supporting or supplemental information submitted by the designated representative;

(ii) The draft offset plan;

(iii) The statement of basis;

(iv) Copies of all documents relied on by the Administrator in approving or disapproving the draft offset plan (including any records of discussions or conferences with owners, operators or the designated representative of the unit or interested persons regarding the draft offset plan) or, for any such documents that are readily available, a statement of their location;

(v) Copies of all written public comments submitted on the draft offset plan or disapproval of a draft offset plan;

(vi) The record of any public hearing on the draft offset plan or disapproval of a draft offset plan;

(vii) The offset plan approved by the Administrator; and

(viii) Any response to public comments submitted on the draft offset plan or disapproval of a draft offset plan, including any documents cited in the response and any other documents relied on by the Administrator or, for any such documents that are readily available, a statement of their location.

(2) The Administrator will approve or disapprove an offset plan within 6 months of receipt of a complete proposed offset plan.

(f) *Statement of Basis.* (1) The statement of basis will briefly set forth significant factual, legal, and policy considerations on which the Administrator relied in approving or disapproving the draft offset plan.

(2) The statement of basis will include:

(i) The reasons, and supporting authority, for approval or disapproval of any proposed offset plan that does not require deduction of allowances during the year after the year for which the plan is submitted, including references to applicable statutory or regulatory provisions and to the administrative record; and

(ii) The name, address, and telephone and facsimile number of the EPA office processing the approval or disapproval of the offset plan.

(g) *Opportunities for Public Comment on Draft Offset Plans.*

(1) *Generally.* (i) The Administrator will give public notice of the following:

(A) The draft offset plan or disapproval of a draft offset plan and the opportunity for public comment and to request a public hearing; and

(B) Date, time, location, and procedures for any scheduled hearing on the draft offset plan or the disapproval of a draft offset plan.

(ii) Any public notice given under this section may be for the approval or disapproval of one or more draft offset plans.

(2) *Methods.* The Administrator will give the public notice required by this section by:

(i) Serving written notice on the following persons (except to the extent any such person has waived his or her right to receive such notice):

(A) The designated representative;

(B) The State or local air pollution agency and any utility regulatory authority with jurisdiction over the owners of the unit covered by the proposed offset plan;

(C) The State or local air pollution agency for any contiguous State whose air quality may be affected by, or for any State located within a 50-mile radius of, the unit covered by the proposed offset plan; and

(D) Any interested person.

(ii) Giving notice by publication in the **Federal Register** and in a newspaper of general circulation in the area where the unit is located or in a State publication designed to give general public notice.

(3) *Contents.* All public notices issued under this part will contain the following information:

(i) Identification of the EPA office processing the approval or disapproval of the draft offset plan for which the notice is being given.

(ii) Identification of the designated representative for the affected unit.

(iii) Identification of each affected unit covered by the proposed offset plan.

(iv) The amount of excess emissions that must be offset and the date on which the allowances are proposed to be deducted.

(v) The address and office hours of a public location where the

administrative record is available for public inspection and a statement that all information submitted by the designated representative and not protected as confidential pursuant to section 114(c) of the Act is available for public inspections as part of the administrative record.

(vi) For public notice under paragraph (g)(1)(i)(A) of this section, a brief description of the public comment procedures, including:

(A) A 30-day public comment period beginning the date of publication of the notice or, in the case of an extension or reopening of the public comment period, such period as the Administrator deems appropriate;

(B) The address where public comments should be sent;

(C) Required formats and contents for public comment;

(D) An opportunity to request a public hearing to occur not earlier than 15 days after public notice is given and the location, date, time, and procedures of any scheduled public hearing; and

(E) Any other means by which the public may participate.

(4) *Extensions and Reopenings of the Public Comment Period.* On the Administrator's own motion, or on the request for any person, the Administrator may, at his or her discretion, extend or reopen the public comment period where he or she finds that doing so will contribute to the decision-making process by clarifying one or more significant issues affecting the draft offset plan or disapproval of a draft offset plan. Notice of any such extension or reopening will be given under paragraph (g)(1)(i)(A) of this section.

(h) *Public comments.* (1) General. During the public comment period, any person may submit written comments on the draft offset plan or disapproval of a draft offset plan.

(2) Form. (i) Comments shall be submitted in duplicate.

(ii) The submission shall clearly indicate the draft offset plan approval or disapproval to which the comments apply.

(iii) The submission shall clearly indicate the name of the commenter, his or her interest, and his or her affiliation, if any, to owners and operators of any unit covered by the proposed offset plan.

(3) Contents. Timely comments on any aspect of a draft offset plan or disapproval of a draft offset plan will be considered unless they concern issues that are not relevant, such as:

(i) The environmental effects of acid rain, acid deposition, sulfur dioxide, or nitrogen oxides generally; and

(ii) Offset plan approval procedures or actions on other proposed offset plans that are not relevant to approval or disapproval of the draft offset plan in question.

(4) Persons who do not wish to raise issues on the draft offset plan or denial of a draft offset plan, but who wish to be notified of any subsequent actions concerning such matter, may so indicate during the public comment period or at any other time. The Administrator will place their names on a list of interested persons.

(i) *Opportunity for Public Hearing.* (1) During the public comment period, any person may request a public hearing. A request for a public hearing shall be made in writing and shall state the issues proposed to be raised in the hearing.

(2) On the Administrator's own motion or on the request of any person, the Administrator may, at his or her discretion, hold a public hearing whenever the Administrator finds that such a hearing will contribute to the decision-making process by clarifying one or more significant issues affecting the draft offset plan or disapproval of a draft offset plan. Public hearings will not be held on issues under paragraphs (h)(3) (i) and (ii) of this section.

(3) During a public hearing under this section, any person may submit oral or written comments concerning the draft offset plan or disapproval of a draft offset plan. The Administrator may set reasonable limits on the time allowed for oral statements and will require the submission of written summaries of each oral statement.

(4) The Administrator will assure that a record is made of the hearing.

(j) *Response to Comments.* (1) The Administrator will consider comments on the draft offset plan or disapproval of a draft offset plan received during the public comment period and any public hearing. The Administrator is not required to consider comments otherwise received.

(2) In approving or disapproving an offset plan, the Administrator will:

(i) Identify any draft offset plan provision or portion of the statement of basis that has been changed and the reasons for the change; and

(ii) Briefly describe and respond to relevant comments under paragraph (j)(1) of this section.

(k) *Approval and Effective Date of Excess Emissions Offset Plans.* (1) After the close of the public comment period, the Administrator will approve an offset plan requiring allowance deductions in an amount equal to the unit's tons of excess emissions or disapprove an offset plan. The Administrator will serve a copy of any approved offset plan and the response to comment on the designated representative for the affected unit involved and serve written notice of the approval or disapproval of the offset plan on any persons who are entitled to written notice under paragraphs (g)(2)(i) (B), (C), and (D) of this section. The Administrator will also give notice in the **Federal Register**.

(2) The Administrator will approve an offset plan requiring deduction from the unit's compliance subaccount, by December 31 of the year after the year for which the report is submitted, of all allowances necessary to offset the excess emissions except to the extent the designated representative of the unit demonstrates that such a deduction will interfere with electric reliability.

(3) Upon approval of the offset plan by the Administrator, the offset plan will be incorporated into the Acid Rain permit in accordance with § 72.84 (automatic permit amendment) and shall supersede any inconsistent provision of the permit.

§ 77.5 Deduction of allowances to offset excess emissions of sulfur dioxide.

(a) The Administrator will deduct allowances to offset excess emissions in accordance with the offset plan approved under § 77.4(b) (1) or (k) or in accordance with § 72.91(b) of this chapter.

(b) The designated representative shall hold enough allowances in the appropriate compliance subaccount to cover the deductions to be made in accordance with paragraph (a) or paragraph (c) of this section.

(c) If the designated representative does not submit a timely and complete proposed offset plan, or if the Administrator disapproves a proposed offset plan under § 77.4 (c) or (k), the Administrator will immediately deduct allowances, from the unit's compliance subaccount on a first-in, first-out basis in accordance with § 73.35(c)(2) of this chapter, equal to the amount of the unit's excess emissions of sulfur dioxide.

(d) If a compliance subaccount does not contain adequate allowances to offset the excess emissions, the Administrator will deduct the required allowances whenever allowances are recorded to that account.

§ 77.6 Penalties for excess emissions of sulfur dioxide and nitrogen oxides.

(a) If excess emissions of sulfur dioxide or nitrogen oxides occur at an affected unit during any year, the owners and operators of the affected unit shall pay, without demand, an excess emissions penalty, as calculated

under paragraph (b) of this section. Such payment shall be submitted to the Administrator no later than 60 days after the end of any year during which excess emissions occurred at an affected unit or, for any increase in excess emissions of sulfur dioxide determined after adjustments made under § 72.91(b) of this chapter, by July 31 of the year in which the adjustments are made. Each day after the applicable deadline that the payment is not submitted shall be a separate violation of this part.

(b) *Penalty Formula.* (1) The following formulas shall be used to determine the excess emissions penalty:

Penalty for excess emissions of sulfur dioxide=$2000/ton × annual adjustment factor × tons of excess emissions of sulfur dioxide.

Penalty for excess emissions of nitrogen oxides=$2000/ton × annual adjustment factor × tons of excess emissions of nitrogen oxides.

(i) The annual adjustment factor will be calculated as follows:

Annual adjustment factor=1+{[CPI(year)–CPI(1990)]/CPI(1990)}

where:

(A) "CPI(year)" is the Consumer Price Index as defined in § 72.2 of this chapter and "year" is the year in which the unit had excess emissions.

(B) "CPI(1990)" is the Consumer Price Index for 1990, as defined in § 72.2 of this chapter.

(ii) The Administrator will publish the annual adjustment factor in the **Federal Register** by October 15 of each year beginning in 1995.

(2) The penalty may be rounded to the nearest dollar after completing the calculation in paragraph (b)(1)(i) of this section.

(3) The penalty for excess emissions of sulfur dioxide shall be paid separately from the payment for excess emissions of nitrogen oxides. Each payment shall be accompanied by a document, in a format prescribed by the Administrator, indicating the unit for which the payment is made, whether the payment is for excess emissions of sulfur dioxide or nitrogen oxides, the number of tons of excess emissions, the penalty amount, and the check or money order number of the payment.

(c) If an excess emissions penalty due under this part is not paid on or before the applicable deadline under paragraph (a) of this section, the penalty shall be subject to interest charges in accordance with the Debt Collection Act (31 U.S.C. 3717). Interest shall begin to accrue on the date on which the Administrator mails, to the designated representative of the unit with excess emissions, a demand notice for the payment.

(d)(1) Except for wire transfers made in accordance with paragraph (d)(2) of this section, payments of penalties shall be made by money order, cashier's check, certified check, or U.S. Treasury check made payable to the "U.S. EPA."

(2) Payments made under paragraph (c)(1) of this section shall be mailed to the following address, unless the Administrator has notified the designated representative of a different address: U.S. EPA: Headquarters Accounting Operations Branch, Acid Rain Excess Emissions Penalties, P.O. Box 952491, St. Louis, MO 63195–2491.

(3) Payments of penalties of $25,000 or more may be made by wire transfer to the U.S. Treasury at the Federal Reserve Bank of New York.

(e) If the Administrator determines that overpayment has been made, he or she will refund the overpayment without interest, as promptly as administratively possible.

(f) Excess emissions in any year resulting directly from an order issued in that year under section 110(f) of the Act shall not be subject to the penalty payment requirements of this section; *provided* that the designated representative of any unit subject to such order shall advise the Administrator within 30 days of issuance of the order that the order will result in such excess emissions.

8. Title 40 is amended by adding part 78 to read as follows:

PART 78—APPEAL PROCEDURES FOR ACID RAIN PROGRAM

Sec.

78.1 Purpose and scope.
78.2 General.
78.3 Petition for administrative review and request for evidentiary hearing.
78.4 Filings.
78.5 Limitation on filing or presenting new evidence and raising new issues.
78.6 Action on petition for administrative review.
78.7 Stays of contested Acid Rain requirements pending appeal.
78.8 Consolidation and severance of appeals proceedings.
78.9 Notice of the filing of petition for administrative review.
78.10 *Ex parte* communications during pendency of a hearing.
78.11 Intervenors.
78.12 Standard of review.
78.13 Scheduling orders and pre-hearing conferences.
78.14 Evidentiary hearing procedure.
78.15 Motions in evidentiary hearings.
78.16 Record of appeal proceeding.
78.17 Proposed findings and conclusions and supporting brief.
78.18 Proposed decision.
78.19 Interlocutory appeal.
78.20 Appeal of decision of Administrator or proposed decision to the Environmental Appeals Board.

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

PART 78—APPEAL PROCEDURES FOR ACID RAIN PROGRAM

§ 78.1 Purpose and scope.

(a) This part shall govern appeals of any decision of the Administrator under the Acid Rain Program that, in the absence of an administrative appeal, will be final agency action; *provided* that matters listed in § 78.3(d) and interim decisions, such as draft Acid Rain permits or proposed alternative monitoring systems, may not be appealed.

(b) The decisions of the Administrator that may be appealed include but are not limited to:

(1) Under part 72 of this chapter;

(i) The determination of incompleteness of an Acid Rain permit application;

(ii) The issuance or denial of an Acid Rain permit and approval or disapproval of a compliance option by the Administrator;

(iii) The approval or disapproval of an early ranking application for Phase I extension under § 72.42 of this chapter;

(iv) The final determination of whether a technology is a qualified repowering technology under § 72.44 of this chapter;

(v) The issuance or denial of a written exemption for new units or retired units under §§ 72.7 and 72.8 of this chapter;

(vi) The approval or disapproval of a permit revision;

(vii) The decision on the deduction or return of allowances under §§ 72.41, 72.42, 72.43, 72.44, 72.91(b), and 72.92 (a) and (c) of this chapter; and

(viii) The failure to issue an Acid Rain permit in accordance with the deadline under § 72.74(b) of this chapter.

(2) Under part 73 of this chapter,

(i) The decision on a claim of error in a transfer recordation;

(ii) The decision on the allocation of allowances from the Conservation and Renewal Energy Reserve;

(iii) The decision on the allocation of allowances under regulations implementing sections 404(e), 405(g)(4), 405(i)(2), and 410(h) of the Act;

(iv) The decision on the allocation of allowances under part 73, subpart F of this chapter;

(v) The decision on the sale or return of allowances and transfer of proceeds under part 73, subpart E; and

(vi) The decision on the deduction of allowances under § 73.35(b) of this chapter.

(3) Under part 75 of this chapter,

(i) The decision on a petition for approval of an alternative monitoring system;

(ii) The approval or disapproval of a monitoring system certification or recertification;

(iii) The finalization of annual emissions data, including retroactive adjustment based on audit;

(iv) The determination of the percentage of emissions reduction achieved by qualifying Phase I technology; and

(v) The determination on the acceptability of parametric missing data procedures for a unit equipped with add-on controls for sulfur dioxide and nitrogen oxides in accordance with part 75 of this chapter.

(4) Under part 77 of this chapter, the determination of incompleteness of an offset plan and the approval or disapproval of an offset plan under §77.4 of this chapter and the deduction of allowances under § 77.5(c) of this chapter.

(c) In order to appeal a decision under paragraph (a) of this section, a person shall file a petition for administrative review with the Environmental Appeals Board under § 78.3. The Environmental Appeals Board will, consistent with §78.6, either:

(1) Issue an order deciding the appeal; or

(2) Where there is a disputed issue of fact material to the contested portions of the decision, refer the proceeding to the Chief Administrative Law Judge, who will designate an Administrative Law Judge to conduct an evidentiary hearing to decide the disputed issue of fact. If the proposed decision is contested or the Environmental Appeals Board decides to review the proposed decision, the Environmental Appeals Board will issue an order deciding the appeal.

(d) Questions arising at any stage of a proceeding that are not addressed in this part will be resolved at the discretion of the Environmental Appeals Board or the Presiding Officer.

§78.2 General.

Part 72 of this chapter, including sections 72.2 (definitions), 72.3 (measurements, abbreviations, and acronyms), 72.4 (federal authority), 72.5 (State authority), 72.6 (applicability), 72.7 (new units exemption), 72.8 (retired units exemption), 72.9 (standard requirements), 72.10 (availability of information), and 72.11 (computation of time), shall apply to this part.

§78.3 Petition for administrative review and request for evidentiary hearing.

(a)(1) The following persons may petition for administrative review of a decision of the Administrator that is made under parts 72, 75, and 77 of this chapter and that is appealable under § 78.1(a) of this part:

(i) The designated representative for the unit covered by the decision;

(ii) The authorized account representative for an account covered by the decision; and

(iii) Any interested person.

(2) The following persons may petition for administrative review of a decision of the Administrator that is made under part 73 of this chapter and that is appealable under § 78.1(a):

(i) The authorized account representative for any Allowance Tracking System account covered by the decision; and

(ii) With regard to the decision on the allocation of allowances from the Conservation and Renewable Energy Reserve, the certifying official whose application is covered by the decision.

(b)(1) Within 60 days following issuance of a decision under § 78.1 of this part by the Administrator, any person under paragraph (a) of this section may file a petition with the Environmental Appeals Board for administrative review of the decision. If no petition for administrative review of a decision under § 78.1 of this part is filed within such period, the decision shall become final agency action.

(2) The petition may include a request for an evidentiary hearing to resolve any disputed issue of material fact concerning the decision.

(3) At the same time that the petition for administrative review is filed, the petitioner shall:

(i) Serve a copy of the petition on the designated representative or authorized account representative under paragraph (a)(1) and (2) of this section (unless the designated representative or authorized account representative is the petitioner) and the Administrator; and

(ii) Mail a notice of the petition to the persons entitled to written notice under § 72.65(b)(1)(ii), (iii), and (iv) of this chapter.

(c) The petition for administrative review under this part shall state with specificity:

(1) Each material factual and legal issue alleged to be in dispute and any such factual issue for which an evidentiary hearing is sought;

(2) A clear and concise statement of the nature and scope of the interest of the petitioner;

(3) A clear and concise brief in support of the petition, explaining why the factual or legal issues are material and, if an evidentiary hearing is requested, why direct and cross-examination of witnesses is necessary to resolve such factual issues;

(4) If an evidentiary hearing is requested, the time estimated to be necessary for an evidentiary hearing;

(5) If an evidentiary hearing is requested, a certified statement that, in the event of an evidentiary hearing, and without cost or expense to any other party, any of the following persons shall be available to appear and testify:

(i) The petitioner; and

(ii) Any officer, director, employee, consultant, or agent of the petitioner.

(6) Specific references to the contested portions of the decision;

(7) Any revised or alternative action of the Administrator sought by the petitioner as necessary to implement the requirements, purposes, or policies of title IV of the Act; and

(8) Identification of any portion of the decision that the petitioner believes should be stayed pending resolution of the appeal.

(d) In no event shall a petition for administrative review be filed, or review be available under this part, with regard to:

(1) A decision under part 73 of this chapter to which the claim of error procedure applies, but for which no claim of error notification was submitted, under part 73 of this chapter;

(2) Any provision or requirement of parts 72, 73, 75, or 77 of this chapter and regulations implementing sections 407 and 410 of the Act, including any standard requirement under § 72.9 of this chapter and any emissions monitoring or reporting requirements under part 75 of this chapter;

(3) The reliance by the Administrator on a certificate of representation submitted by a designated representative or a certification statement submitted by an authorized account representative under the Acid Rain Program; and

(4) Actions of the Administrator under sections 112(r), 113, 114, 120, 301, and 303 of the Act.

§78.4 Filings.

(a) All original filings made under this part shall be signed by the person making the filing or by an attorney or authorized representative. Any filings on behalf of owners and operators of an affected unit or affected source shall be signed by the designated representative. Any filings on behalf of persons with an interest in allowances in a general account shall be signed by the authorized account representative. The name, address, telephone number, and

facsimile number of the person making the filing shall be provided with the filing.

(b)(1) All data and information referred to, or in any way relied upon, in any filings made under this part shall be included in full and may not be incorporated by reference, unless the data or information is contained in the administrative record for the decision being appealed.

(2) Notwithstanding paragraph (b)(1) of this section, State or federal statutes, regulations, and judicial decisions published in a national reporter system, officially issued EPA documents of general applicability, and any other publicly and generally available reference material may be incorporated by reference. Any person incorporating such materials by reference shall provide copies of the materials as instructed by the Environmental Appeals Board or the Presiding Officer.

(3) If any part of any filing is in a foreign language, it shall be accompanied by an English translation verified by the person making the translation, under oath, to be complete and accurate, together with the name, address, and a brief statement of the qualifications of the person making the translation. Translations filed of material originally produced in a foreign language shall be accompanied by copies of the original material.

(4) Where relevant data or information is contained in a document also containing irrelevant matter, either the irrelevant matter shall be deleted or an index to the relevant portions of the document shall be included in the document.

(c)(1) Failure to comply with the requirements of this section or any other requirement in this part may result in the noncomplying portions of the filing being excluded from consideration. If the Environmental Appeals Board or the Presiding Officer determines on motion by any party or *sua sponte* that a filing fails to meet any requirement of this part, the Environmental Appeals Board or Presiding Officer may return the filing, together with a reference to the applicable requirements on which the determination is based. A person whose filing has been rejected has 7 days, from the date the returned filing is mailed, to correct the filing in conformance with this part and refile it, unless the Environmental Appeals Board or Presiding Officer authorizes a longer time based on good cause shown.

(2) The making of a filing shall not mean or imply that the filing, in fact, meets all applicable requirements, that the filing contains reasonable grounds for the action requested, or that the action requested is in accordance with law.

(d) An original and two copies of any written filing under this part shall be filed with the Environmental Appeals Board unless a proceeding is pending before a Presiding Officer, in which case they shall be filed with the Hearing Clerk (except as provided under § 78.19(d)) of this part.

(e)(1) The party making any filing in a proceeding under this part shall also serve a copy of the filing on each party to the proceeding, or, with regard to a petition for administrative review, on the persons specified in § 78.3(b)(3) of this part.

(2) Every filing made under this part shall be accompanied by a certificate of service citing the date, place, time, and manner of service and the names of the persons served.

(f) The Hearing Clerk will maintain and furnish, to any person upon request, the official service list containing the name, service address, telephone, and facsimile numbers of each party to a proceeding under this part and his or her attorney or duly authorized representative.

(g) Affidavits filed under this part shall be made on personal knowledge and belief, set forth only those facts that are admissible into evidence under § 78.5 of this part, and show affirmatively that the affiant is competent to testify to the matters stated therein.

§ 78.5 Limitation on filing or presenting new evidence and raising new issues.

(a) Where there was an opportunity for public comment, or to submit a claim of error notification, prior to the decision that is subject to appeal, no evidence shall be filed or presented, and no issues raised, in a proceeding under this part that were not filed, presented, or raised during the public comment period, absent a showing of good cause explaining the party's failure to do so during the public comment period or in the claim of error notification. Good cause shall include any instance where the party seeking to file or present new evidence or raise a new issue shows that the evidence could not have reasonably been ascertained, filed, or presented, the issue could not have reasonably been ascertained or raised, or that the materiality of the new evidence or issue could not have reasonably been anticipated, prior to the close of the public comment period or the period for submitting a claim of error notification.

(b) If an evidentiary hearing is granted, no evidence shall be filed or presented on questions of law or policy or on matters not subject to challenge in the evidentiary hearing.

§ 78.6 Action on petition for administrative review.

(a) If no evidentiary hearing concerning the petition for review is requested or is to be held, the Environmental Appeals Board will issue an order under § 78.20(c) of this part.

(b)(1) The Environmental Appeals Board may grant a request for an evidentiary hearing, or schedule an evidentiary hearing *sua sponte*, if the Environmental Appeals Board finds that there are disputed issues of fact material to contested portions of the decision and determines, in its discretion, that an opportunity for direct- and cross-examination of witnesses may be necessary in order to resolve these factual issues.

(2) To the extent the Environmental Appeals Board grants a request for an evidentiary hearing, in whole or in part, it will:

(i) Identify the portions of the decision that have been contested, and the disputed factual issues that have been raised by the petitioner with regard to which the evidentiary hearing has been granted; and

(ii) Refer the disputed factual issues to the Chief Administrative Law Judge for decision and, in its discretion, may also refer all or a portion of the remaining legal, policy, or factual issues to the Chief Administrative Law Judge for decision.

(3)(i) After issues are referred to the Chief Administrative Law Judge, he or she will designate an Administrative Law Judge as Presiding Officer to conduct the evidentiary hearing.

(ii) Notwithstanding paragraph (b)(3)(i) of this section, if all parties waive in writing their right to have an Administrative Law Judge designated as the Presiding Officer, the Administrator may designate a lawyer permanently or temporarily employed by EPA and without any prior connection with the proceeding to serve as Presiding Officer.

§ 78.7 Stays of contested Acid Rain requirements pending appeal.

(a) A contested decision of the Administrator may be stayed, in whole or in part consistent with paragraph (b) of this section, by the Environmental Appeals Board or the Presiding Officer upon request of a party during a proceeding under this part only to the extent necessary to prevent irreparable injury pending final agency action.

(b) The following requirements shall in no event be stayed due to any appeal of a decision of the Administrator and shall be fully effective and enforceable:

(1) The allowance allocations for any year during which the appeal proceeding is pending or is being conducted;

(2) Any standard requirements under § 72.9 of this chapter;

(3) The emissions monitoring and reporting requirements applicable to the affected units at an affected source under part 75 of this chapter;

(4) Uncontested provisions of the decision; and

(5) The terms of a certificate of representation submitted by a designated representative under part 72, subpart B of this chapter or a certification statement submitted by an authorized account representative under part 73, subpart C of this chapter.

(c) The permit shield under § 72.51 of this chapter shall continue to be in effect.

(d) The Environmental Appeals Board or Presiding Officer shall specify which provisions of the decision shall be stayed.

§ 78.8 Consolidation and severance of appeals proceedings.

(a) The Environmental Appeals Board or Presiding Officer has the discretion to consolidate, in whole or in part, two or more proceedings under this part whenever it appears that a joint proceeding on any or all of the matters at issue in the proceedings will be in the interest of justice, will expedite or simplify consideration of the issues, and will not prejudice any party. Consolidation of proceedings under this paragraph (a) will not affect the right of any party to raise issues that might have been raised had there been no consolidation.

(b) The Environmental Appeals Board or Presiding Officer has the discretion to sever issues or parties from a proceeding under this part whenever it appears that separate proceedings will be in the interest of justice, will expedite or simplify consideration of the issues, and will not prejudice any party.

§ 78.9 Notice of the filing of petition for administrative review.

The Administrator will publish in the **Federal Register** a notice stating that a petition for administrative review of a decision of the Administrator has been filed and specifying any request in the petition for an evidentiary hearing.

§ 78.10 Ex parte communications during pendency of a hearing.

(a)(1) No party or interested person outside EPA, representative of a party or interested person, or member of the EPA trial staff shall make, or knowingly cause to be made, to any member of the decisional body an *ex parte* communication on the merits of a proceeding under this part.

(2) No member of the decisional body shall make, or knowingly cause to be made, to any party or interested person outside EPA, representative of a party or interested person, or member of the EPA trial staff, an *ex parte* communication on the merits of any proceeding under this part.

(3) A member of the decisional body who receives, makes, or knowingly causes to be made an *ex parte* communication prohibited by this paragraph shall file with the Environmental Appeals Board (or, if the proceeding is pending before an Administrative Law Judge, with the Hearing Clerk) for inclusion in the record of the proceeding under this part any such written *ex parte* communication and memoranda stating the substance of any such oral *ex parte* communication.

(b) Whenever any member of the decisional body receives an *ex parte* communication made, or knowingly caused to be made by a party or representative of a party to a proceeding under this part, the person presiding over the proceedings then in progress may, to the extent consistent with justice, require the party to show good cause why its claim or interest in the proceedings should not be dismissed, denied, disregarded, or otherwise adversely affected on account of these *ex parte* communications.

(c) The prohibitions of paragraph (a) of this section shall begin to apply upon publication by the Administrator of the notice of the filing of a petition under § 78.9 of this part. This prohibition terminates on the date of final agency action.

§ 78.11 Intervenors.

(a) Within 30 days after notice is given under § 78.9 of this part that the petition for administrative review has been filed, any person listed in § 78.3(a) of this part may file a motion for leave to intervene in the proceeding. A motion for leave to intervene under this section shall set forth the grounds for the proposed intervention and may respond to the petition for administrative review. Late motions to intervene may be granted only for good cause shown.

(b) The Environmental Appeals Board of Presiding Officer will grant a motion to intervene only upon an express finding that:

(1) The motion to intervene raises matters relevant to the factual or legal issues to be reviewed;

(2) The intervenor consented to be bound by all stipulations previously entered into by the existing parties, and all orders previously issued, in the proceeding; and

(3) The intervention will promote the interests of justice and will not cause undue delay or prejudice to the rights of the existing parties.

§ 78.12 Standard of review.

(a) On appeal of a decision of the Administrator prior to which there was an opportunity for public comment, or to submit a claim of error notification:

(1) Except as provided under paragraph (a)(2) of this section, the petitioner shall have the burden of going forward and of persuasion to show that a finding of fact or conclusion of law underlying the decision is clearly erroneous or that an exercise of discretion or policy determination underlying the decision is arbitrary and capricious or otherwise warrants review.

(2) The owners and operators of the source or unit involved shall have the burden of persuasion that an Acid Rain permit or a written exemption under §§ 72.7 or 72.8 of this chapter was properly issued or should be issued.

(b) On appeal of a decision of the Administrator not covered by paragraph (a) of this section, the Administrator shall have the burden of going forward to show the rational basis for the decision. The petitioner shall have the burden of persuasion to show that a finding of fact or conclusion of law underlying the decision is clearly erroneous or that an exercise of discretion or policy determination underlying the decision is arbitrary and capricious or otherwise warrants review.

§ 78.13 Scheduling orders and pre-hearing conferences.

(a) If a request for an evidentiary hearing is granted, the Presiding Officer will issue an order scheduling the following:

(1) The filing by each party of a narrative statement of position on each factual issue in controversy.

(2) The identification of any witness that a party expects to call and of any written testimony, documents, papers, exhibits, or other materials that a party expects to introduce into evidence. At the request of the Presiding Officer, the party shall include a brief narrative summary of any witness' expected testimony and of any such materials.

(3) The filing of written testimony, in accordance with § 78.14(b) of this part, and other evidence in support of a narrative statement.

(4) The filing of any motions by any party, including motions for the

production of documentation, data, or other information material to the disputed facts to be addressed at the hearing.

(b) The Presiding Officer may also, on motion or *sua sponte*, schedule one or more pre-hearing conferences on the record to address any of the following:

(1) Simplification, clarification, amplification, or limitation of the issues.

(2) Admissions and stipulations of facts and determinations of the genuineness of documents.

(3) Objections to the introduction into evidence at the hearing of any written testimony or other submissions proposed by a party; *provided* that at any time before the end of the hearing, any party may make, and the Presiding Officer may consider and rule upon, a motion to strike testimony or other evidence (other than evidence included in the administrative record (if any) under § 72.63 of this chapter) on the grounds of relevance, competency, or materiality.

(4) Taking official notice of any matters.

(5) Grouping of parties with substantially similar interests to eliminate redundant evidence, motions, objections, and briefs.

(6) Such other matters that may expedite the hearing or aid in the disposition of matters in dispute.

(c) The Presiding Officer will issue an order (which may be in the form of a transcript) reciting the actions taken at any pre-hearing conferences, setting the schedule for any hearing, and stating any areas of factual and legal agreement and disagreement and the methods and procedures to be used in developing any evidence.

§ 78.14 Evidentiary hearing procedure.

(a) If a request for an evidentiary hearing is granted, the Presiding Officer will conduct a fair and impartial hearing on the record, take action to avoid unnecessary delay in the disposition of the proceedings, and maintain order. For theses purposes, the Presiding Officer may:

(1) Administer oaths and affirmations.

(2) Regulate the course of the hearings and prehearing conferences and govern the conduct of participants.

(3) Examine witnesses.

(4) Identify and refer issues for interlocutory decision under § 78.19 of this part.

(5) Rule on, admit, exclude, or limit evidence.

(6) Establish the time for filing motions, testimony and other written evidence, and briefs and making other filings.

(7) Rule on motions and other pending procedural matters, including but not limited to motions for summary disposition in accordance with § 78.15 of this part.

(8) Order that the hearing be conducted in stages whenever the number of parties is large or the issues are numerous and complex.

(9) Allow direct and cross-examination of witnesses only to the extent the Presiding Officer determines that such direct and cross-examination may be necessary to resolve disputed issues of material fact; *provided* that no direct or cross-examination shall be allowed on questions of law or policy or regarding matters that are not subject to challenge in the evidentiary hearing.

(10) Limit public access to the hearing where necessary to protect confidential business information. The Presiding Officer will provide written notice of the hearing to the parties, and where the hearing will be open to the public, notice in the **Federal Register** no later than 15 days prior to commencement of the hearings.

(11) Take any other action not inconsistent with the provisions of this part for the maintenance of order at the hearing and for the expeditious, fair and impartial conduct of the proceeding.

(b) All direct and rebuttal testimony at an evidentiary hearing shall be filed in written form, unless, upon motion and good cause shown, the Presiding Officer, in his or her discretion, determines that oral presentation of such evidence on any particular factual issue will materially assist in the efficient resolution of the issue.

(c)(1) The Presiding Officer will admit all evidence that is not irrelevant, immaterial, unduly repetitious, or otherwise unreliable or of little probative value. Evidence relating to settlement that would be excluded in the federal courts under Rule 408 of the Federal Rules of Evidence shall not be admissible.

(2) Whenever any evidence or testimony is excluded by the Presiding Officer as inadmissible, all such evidence will remain a part of the record as an offer of proof. The party seeking the admission of oral testimony may make an offer of proof by means of a brief statement on the record describing the testimony excluded.

(3) When two or more parties have substantially similar interests and positions, the Presiding Officer may limit the number of attorneys or authorized representatives who will be permitted to examine witnesses and to make and argue motions and objections on behalf of those parties.

(4) Rulings of the Presiding Officer on the admissibility of evidence or testimony, the propriety of direct and cross-examination, and other procedural matters will appear in the record of the hearing and control further proceedings unless reversed by the Presiding Officer or as a result of an interlocutory appeal taken under § 78.19 of this part.

(5) All objections shall be made promptly or be deemed waived; *provided* that parties shall be presumed to have taken exception to an adverse ruling. No objection shall be deemed waived by further participation in the hearing.

§ 78.15 Motions in evidentiary hearings.

(a) Any party may make a motion to the Presiding Officer on any matter relating to the evidentiary hearing in accordance with the scheduling orders issued under § 78.13 of this part. All motions shall be in writing and served as provided in § 78.4 of this part, except those made on the record during an oral hearing before the Presiding Officer.

(b) Any party may make a motion for a summary disposition in its favor on any factual issue on the basis that there is no genuine issue of material fact. When a motion for summary disposition is made and supported, any party opposing the motion may not rest upon mere allegations or denials, but must show, by affidavit or by other materials subject to consideration by the Presiding Officer, that there is a genuine issue of material fact.

(c) Within 10 days after a motion made on the record or service of any written motion, any party may file a response to the motion. The time for response may be shortened or extended by the Presiding Officer for good cause shown.

(d) The Presiding Officer may schedule an oral argument and call for the filing of briefs on any motion. The Presiding Officer will rule on the motion within a reasonable time after the date that responses to the motion may be filed under paragraph (c) of this section and that any oral argument or filing of briefs is completed.

(e) If all factual issues are decided by summary disposition prior to the hearing, no hearing will be held and the Presiding Officer will issue a proposed decision under § 78.18 of this part. If a summary disposition is denied or if partial summary disposition is granted, the hearing shall proceed on the remaining issues.

§ 78.16 Record of appeal proceeding.

(a) The proposed decision issued by the Presiding Officer, transcripts of oral hearings or oral arguments, written

direct and rebuttal testimony, and any other written materials of any kind filed in the proceeding will be part of the record and will be available to the public in the office of the Hearing Clerk, subject to the requirements of part 2 of this chapter.

(b) Hearings and oral arguments shall be recorded as specified by the Presiding Officer, and thereupon transcribed. After the hearing or oral argument, the reporter will certify and file with the Hearing Clerk.

(1) The original transcript; and

(2) Any exhibits received or offered into evidence at the hearing.

(c) The Hearing Clerk will promptly give written notice to the parties when any transcript is available. Any party that desires a copy of the transcript may obtain a copy upon payment of costs.

(d) The Presiding Officer will allow witnesses, parties, and their counsel or representatives:

(1) Up to 7 days from issuance of the notice under paragraph (c) of this section in order to file written proposed corrections of the transcript necessary to correct errors made in the transcribing; and

(2) Up to 7 days from the submission of the corrections in order to file objections to the proposed corrections.

(e) The Presiding Officer will determine which, if any, corrections should be made to the transcript and incorporate them into the record.

§ 78.17 Proposed findings and conclusions and supporting brief.

Within 45 days after issuance of a notice under § 78.16(c) of this part that the complete transcript of the evidentiary hearing is available, any party may file with the Hearing Clerk proposed findings and conclusions on the issues referred to the Presiding Officer and a brief in support thereof. Briefs shall contain appropriate references to the record. The Presiding Officer, for good cause shown, may shorten or extend the time for filing and may allow reply briefs.

§ 78.18 Proposed decision.

(a) The Presiding Officer will review and evaluate the record, including the proposed findings and conclusions and any briefs filed by the parties, and issue a proposed decision on the factual, policy, and legal issues referred by the Environmental Appeals Board for decision under § 78.6(b)(2)(ii) of this part, accompanied by findings of fact and proposed conclusions of law, as appropriate, within a reasonable time after the evidentiary hearing is completed. The Hearing Clerk will promptly serve copies of the proposed decision on all parties and on the Environmental Appeals Board.

(b) The proposed decision of the Presiding Officer shall become the final agency action under section 307 of the Act 30 days after service unless within that time:

(1) A party files objections with the Environmental Appeals Board pursuant to § 78.20(a) of this part, or

(2) The Environmental Appeals Board *sua sponte* files a notice that it will review the decision under § 78.20(b) of this part.

§ 78.19 Interlocutory appeal.

(a) Interlocutory appeal from orders or rulings of the Presiding Officer made during the course of a proceeding may be taken if the Presiding Officer certifies those orders or rulings to the Environmental Appeals Board for interlocutory appeal on the record. Any requests to the Presiding Officer to certify an interlocutory appeal shall be filed within 10 days of notice of the order or ruling and shall state briefly the grounds for the request.

(b)(1) Within 15 days of the filing of any request for interlocutory appeal, the Presiding Officer may certify an order or ruling for interlocutory appeal to the Environmental Appeals Board if:

(i) The order or ruling involves an important question on which there is substantial ground for difference of opinion, and

(ii) Either:

(A) An immediate appeal of the order or ruling will materially advance the ultimate completion of the proceeding, or

(B) A review after the proceeding is completed will be inadequate or ineffective.

(2) If the Presiding Officer takes no action within 15 days of the filing of a request for interlocutory appeal, the request shall be automatically dismissed without prejudice.

(c) If the Presiding Officer grants certification, the Environmental Appeals Board may accept or decline the interlocutory appeal within 30 days of certification. If the Environmental Appeals Board decides that certification was improperly granted, it will decline to hear the interlocutory appeal. If the Environmental Appeals Board takes no action within 30 days of certification, the interlocutory appeal shall be automatically dismissed without prejudice.

(d) If the Presiding Officer declines to certify an order or ruling for an interlocutory appeal, the order or ruling may be reviewed by the Environmental Appeals Board only upon an appeal of the proposed decision following completion of the proceedings before the Presiding Officer, except when the Environmental Appeals Board determines, upon motion of a party and in exceptional circumstances, that to delay review would not be in the public interest. Such motion shall be filed with Environmental Appeals Board within 5 days after the earlier of automatic dismissal of the request for interlocutory appeal or receipt by the party of notification that the Presiding Officer declines to certify an order or ruling for interlocutory appeal.

(e) The failure of a party to request an interlocutory appeal shall not prevent an appeal of an order or ruling as part of an appeal of a proposed decision under § 78.20 of this part.

§ 78.20 Appeal of decision of Administrator or proposed decision to the Environmental Appeals Board.

(a) Within 30 days after the issuance of a proposed decision by a Presiding Officer under this part, any party may appeal any matter set forth in the proposed decision, or any other order or ruling made during the proceeding to which the party objected during the proceeding before the Presiding Officer, by filing an objection with the Environmental Appeals Board. On appeal of an order, ruling, or proposed decision of a Presiding Officer:

(1) The party filing the objection shall have the burden of going forward to show that the order, ruling, or proposed decision is based on a finding of fact or conclusion of law that is clearly erroneous; or a policy determination or exercise of discretion that is arbitrary and capricious or otherwise warrants review; and

(2) The petitioner or the owners and operators shall have the burden of persuasion, as set forth in § 78.12(a) (1) and (2) of this part.

(b) Within 30 days after issuance of a proposed decision of a Presiding Officer, the Environmental Appeals Board may issue *sua sponte* in its discretion a notice of intent to review such proposed decision. The Environmental Appeals Board will serve such notice upon all parties to the proceeding.

(c) Within a reasonable time following the filing of a petition for administrative review of a decision of the Administrator under § 78.3 of this part, or, if any issues raised by such petition are referred to the Presiding Officer, the filing of objections under paragraph (a) of this section or the issuance of a notice of intent to review under paragraph (b) of this section, the Environmental Appeals Board will issue an order affirming, reversing, modifying, or

remanding the decision or proposed decision, as appropriate. Prior to issuing this order, the Environmental Appeals Board may provide an opportunity for parties to file additional briefs.

(d) If the Environmental Appeals Board issues an order affirming, reversing, or modifying the decision of the Administrator, then the decision as supplemented or changed by the order, shall be final agency action.

(e) If the Environmental Appeals Board issues an order affirming, reversing, or modifying the proposed decision, the proposed decision, as supplemented or changed by the order, shall be final agency action.

(f) If the Environmental Appeals Board issues an order remanding the proceeding, then final agency action occurs upon completion of the remanded proceeding, including any appeals to the Environmental Appeals Board in the remanded proceeding.

[FR Doc. 93–1 Filed 1–8–93; 8:45 am]

BILLING CODE 6560–50–M

federal register

Monday
January 11, 1993

Part III

Environmental Protection Agency

40 CFR Part 51

Criteria and Procedures for Determining Conformity to Transportation Plans; Proposed Rule

asked to refrain from engaging the staff or its contractor in discussions of the merits of the projects outside of any announced meetings.

Further, interested persons are reminded of the Commission's Rules of Practice and Procedure, requiring parties or interceders (as defined in 18 CFR 385.2010) filing documents with the Commission, to serve a copy of the document on each person whose name is on the official service list for this proceeding. *See* 18 CFR 4.34(b).

For further information please contact Kathleen Sherman at (202) 219–2834.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–16264 Filed 7–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. CP93–517–000]

Arkla Energy Resources Co.; Application

July 2, 1993.

Take notice that on June 25, 1993, Arkla Energy Resources Company (AER), P.O. Box 21734, Shreveport, Louisiana 71151, filed an application with the Commission in Docket No. CP93–517–000 pursuant to section 7(b) of the Natural Gas Act (NGA) for permission and approval to abandon the transportation of natural gas for a direct sales customer, Central Louisiana Electric Company, Inc. (CLECO), which was authorized in Docket No. CP81–400–000,[1] all as more fully set forth in the application which is open to the public for inspection.

AER proposes to abandon the firm transportation of up to 50,000 MMBtu equivalent of natural gas per day,[2] because their sales contract expired January 1, 1992, and CLECO has made other arrangements for its natural gas supplies. AER would not abandon any facilities in this proposal.

Any person desiring to be heard or to make any protest with reference to said application should on or before July 22, 1993, file with the Federal Energy Regulatory Commission, Washington, DC 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the NGA (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no motion to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that permission and approval for the proposed amendment are required by the public convenience and necessity. If a motion for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for AER to appear or be represented at the hearing.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–16265 Filed 7–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket Nos. TQ93–10–63–000 and TM93–10–63–000]

Carnegie Natural Gas Co.; Proposed Changes in FERC Gas Tariff

July 2, 1993.

Take notice that on June 30, 1993, Carnegie Natural Gas Company (Carnegie) tendered for filing the following revised tariff sheets to its FERC Gas Tariff, Second Revised Volume No. 1:

Forty-Fifth Revised Sheet No. 8
Forty-Fifth Revised Sheet No. 9

Carnegie states that pursuant to sections 23 and 26 of the General Terms and Conditions of its FERC Gas Tariff, it is filing a combined Out-of-Cycle Purchased Gas Adjustment (PGA) and Transportation Cost Adjustment (TCA) to reflect changes in its projected purchased gas costs and projected Account No. 858 costs. The proposed effective date of the tendered tariff sheets is July 1, 1993.

Carnegie states that the revised tariff sheets incorporate a decrease of $0.3681 per Dth in the commodity PGA sales rates under Carnegie's Rate Schedules CDS and LVWS, as well as to the maximum and minimum PGA rates under Rate Schedule SEGSS, and a TCA demand rate increase of $1.6045 per Dth, a TCA commodity rate decrease of $0.0096 per Dth, and an increase in the DCA charge of $0.0527 per Dth, as compared to Carnegie's most recent PGA and TCA filing in Docket Nos. TQ93–8–63–001 and TM93–8–63–001, filed on June 11, 1993, and supplemented on June 17 and June 23, 1993.

Carnegie states that the commodity PGA rate decrease was necessitated by revised projections in Carnegie's purchased gas costs due to an unanticipated decline in the cost of spot gas supplies available on and after July 1, 1993, and that the TCA demand rate increase was necessitated by a reservation charge increased recently proposed by Carnegie's upstream pipeline, Texas Eastern Transmission Corporation ("TETCO"), to recover gas supply realignment costs pursuant to Order No. 636, citing TETCO's filing on May 28, 1993, in Docket No. RP93–125–000.

Carnegie states that copies of its filing were served on all jurisdictional customers and interested state commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with 18 CFR 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests should be filed on or before July 12, 1993. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the public reference room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 93–16271 Filed 7–8–93; 8:45 am]

BILLING CODE 6717–01–M

[Docket No. TA93–1–24–000]

Equitrans, Inc.; Proposed Changes in FERC Gas Tariff

July 2, 1993.

Take notice that on July 1, 1993, Equitrans, Inc. (Equitrans), tendered for filing as part of its FERC Gas Tariff, Original Volume No. 1, the following tariff sheets with a proposed effective date of September 1, 1993:

Forty-Fourth Revise Sheet No. 10
Thirty-Second Revised Sheet No. 34

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[1] See order issued at 18 FERC ¶ 61,220 (1982).

[2] See order issued at 35 FERC ¶ 61,089 (1986).