Continuous Emission Monitoring Guide

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ACRONYMS and UNITS of MEASURE

AAR - Authorized Account Representative

AGA - American Gas Association

API - American Petroleum Institute

ARP - Acid Rain Program

ASME - American Society of Mechanical Engineers

ASTM - American Society of Testing and Materials

BAF - Bias Adjustment Factor

CAIR - Clean Air Interstate Regulation

CAMD - Clean Air Markets Division

CAMR - Clean Air Mercury Regulation

CDV - Conditional Data Validation

CEM - Continuous Emission Monitoring

CEMS - Continuous Emission Monitoring System

CFR - Code of Federal Regulations

CO_2 - Carbon Dioxide

DAHS - Data Acquisition and Handling System

DP - Differential Pressure

DR - Designated Representative

EDR - Electronic Data Reporting

EGU - Electric Generating Unit

EPA - Environmental Protection Agency

ETS - Emissions Tracking System

GCV - Gross Calorific Value

GHR - Gross heat Rate

GPA - Gas Processors Association

Hg - Mercury

ISO - International Organization for Standardization

LME - Low Mass Emissions

MDC - Monitoring Data Checking

MER - Maximum Potential Emission Rate (MER)

NBP - NO_x Budget Trading Program

NIST - National Institute of Standards and Technology

NSPS - New Source Performance Standards

NO_x - Nitrogen Oxides

O_2 - Oxygen

OOC - Out-of-Control

PLC - Programmable Logic Controller

PMA - Percent Monitor Data Availability

PNG - Pipeline Natural Gas

QA/QC - Quality Assurance/Quality Control

RA - Relative Accuracy

RATA - Relative Accuracy Test Audit

RM - Reference method

SIP - State Implementation Plan

SO_2 - Sulfur Dioxide

TTFA - Targeting Tool for Field Audits

WAF - Wall Effects Adjustment Factor

Btu - British thermal unit

dscfh - Dry standard cubic feet per hour

dscf/mmBtu - Dry standard cubic feet per million Btu

lb/hr - Pounds per hour

lb/mmBtu - Pounds per million Btu

lb/scf - Pounds per standard cubic foot

mmBtu/hr - Million Btu per hour

ppmv - Parts per million by volume

scfh - Standard cubic feet per hour

scf CO_2/mmBtu - Standard cubic feet of CO_2 per million Btu

tons/hr - Tons per hour

tons/scf - Tons per standard cubic foot

µg/scm - Micrograms per standard cubic meter

1.0 INTRODUCTION

1.1 What is the purpose of this guide?

EPA has developed this plain-English guide as a "road map" to help interested parties navigate through the complex Part 75 continuous emission monitoring rule. This guide may be useful to people responsible for complying with the rule, regulatory agencies assessing compliance with the rule, and others who want a general understanding of the emissions monitoring approach used in EPA's emissions trading programs.

This guide, although quite comprehensive, does not replace the Part 75 rule. Rather, it provides a general overview of Part 75 and is intended to clarify the regulation. To gain a more complete understanding of the rule, it is necessary to carefully read and study Part 75, as well as the associated guidance documents issued by EPA, such as the "Part 75 Emissions Monitoring Policy Manual" and the "Electronic Data Reporting Instructions").

For further information on EPA's emissions trading programs, continuous emissions monitoring, Part 75, and related topics, see the EPA Clean Air Markets Division (CAMD) website at: www.epa.gov/airmarkets

1.2 What is Part 75 and who must comply with it ?

The Part 75 continuous emission monitoring rule, which is found in Volume 40 of the Code of Federal Regulations (CFR), was originally published in January, 1993. The purpose of the regulation was to establish continuous emission monitoring (CEM) and reporting requirements under EPA's Acid Rain Program (ARP), which was instituted in 1990 under Title IV of the Clean Air Act. The ARP regulates electric generating units (EGUs) that burn fossil fuels such as coal, oil and natural gas and that serve a generator > 25 megawatts. For these units, Part 75 requires continuous monitoring and reporting of sulfur dioxide (SO_2) mass emissions, carbon dioxide (CO_2) mass emissions, nitrogen oxides (NO_x) emission rate, and heat input. The SO_2 component of the ARP is a "cap and trade" program, designed to reduce acid deposition by limiting SO_2 emission levels in the "lower 48" states of the U.S.

In October, 1998, EPA added Subpart H to Part 75, which provides a blueprint for the monitoring and reporting of NO_x mass emissions and heat input under a State or Federal NO_x emissions reduction program. The Agency anticipated that such programs were likely to come into existence, due to growing concern over health hazards associated with NO_x emissions from power plants and large industrial sources. NO_x is a precursor to ozone and fine particulate matter formation. Subpart H has since been adopted as the required monitoring methodology for NO_x mass emissions and heat input under the NO_x Budget Trading Program (NBP).

The NBP is a NO_x cap and trade program, designed to limit ground-level ozone formation during the ozone season (from May 1st through September 30th) in 22 states in the Eastern U.S.

The state regulations for the NBP apply mainly to large EGUs and industrial boilers, although certain states have included other categories of NO_x-emitting sources, such as cement kilns and refinery process heaters. The state rules are patterned after a model regulation developed by EPA (40 CFR Part 96), and require NO_x mass emissions and heat input to be monitored and reported according to Subpart H of Part 75. The Program assigns a total NO_x emissions budget (tons per ozone season) to each state, and is administered jointly by the states and EPA's Clean Air Markets Division (CAMD).

On May 12 and May 18, 2005, EPA published two new air regulations, the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). These regulations provide model rules for cap and trade programs that can be adopted by the states. The CAIR rule seeks to reduce fine particulate and ozone emissions by imposing tight emission caps on SO_2 and NO_x mass emissions from EGUs in 28 states. CAIR includes annual SO_2 and NO_x emissions caps for 23 of the 28 affected states and an ozone season cap on NO_x emissions in 25 of the states. The CAMR rule seeks to achieve substantial reductions in mercury (Hg) mass emissions from coal-fired EGUs in all 50 states.

Both CAIR and CAMR require Part 75 monitoring. Under CAIR, monitoring systems for NO_x mass emissions and heat input must be installed and certified by 2008, and monitoring systems for SO_2 mass emissions and heat input must be certified by 2009. Under CAMR, Part 75-compliant monitoring systems for Hg mass emissions and, if required, heat input must be installed and certified by January 1, 2009. For a further discussion of these new rules, see Appendix I of this guide.

Part 75 specifies the types of continuous monitoring systems that may be used for each parameter (SO_2, NO_x, Hg, etc.) and sets forth the operation, maintenance and quality assurance/quality control (QA/QC) requirements for each system. In most cases, continuous emission monitoring systems (CEMS) are required, although in some instances, other monitoring methodologies are allowed.

Table 1 summarizes the various programs that require (or will require) Part 75 monitoring. Each of these programs requires certain parameters to be monitored over specified time periods. For each affected unit, the specific parameters that must be monitored, the units of measure, and the averaging (or accounting) periods depend on which program(s) apply.

Table 1 also shows that when the same pollutant is regulated under two different programs, the Part 75 monitoring and reporting requirements for the pollutant are not necessarily consistent between the two programs. For example, the ARP and NBP assess NO_x compliance differently. The ARP requires the NO_x emission rate to be monitored and reported in pounds per million Btu (lb/mmBtu) and specifies annual NO_x emission rate limits for certain coal-fired EGUs, under 40 CFR Part 76. But the ARP does not have an emissions trading component for NO_x, and therefore does not require NO_x mass emissions to be reported[1]. Conversely, the NBP, which is a NO_x cap and trade program, does require NO_x mass emissions to be monitored and

[1] There is one exception to this. For low mass emissions (LME) units in the Acid Rain Program, NO_x mass emissions are reported in addition to NO_x emission rate, to demonstrate that the unit continues to qualify for LME status from year-to-year. LME units are discussed in detail in Section 6 of this guide.

Table 1: Programs That Require Part 75 Monitoring

Program	Affected Sources	Parameter(s) Measured (units)	Accounting or Averaging Period	Data Used for Program Compliance ?
Acid Rain Program	EGUs and other combustion sources that opt-in to the SO_2 cap and trade program	SO_2 (tons) CO_2 (tons) NO_x (lbs/mmBtu) Heat input (mmBtu) Opacity[g] (%)	Annual (cumulative) Annual (cumulative) Annual (average) Annual (cumulative) Varies[h]	Yes[a] No[b] Certain units only[c] In some cases[d] No
NO_x Budget Trading Program	EGUs , certain large industrial units, and units that opt in to the cap and trade program	NO_x (tons) Heat input (mmBtu)	Ozone season[5] (cumulative) Ozone season[e] (cumulative)	Yes[a] In some cases[f]
Trading Programs under the CAIR Regulation[9]	EGUs and opt-in units	SO_2 and NO_x (tons) NO_x (tons)	Annual (cumulative)–23 states Ozone season[e] (cumulative)— 25 states	Yes[a]
Trading Program under the CAMR Rule[i]	Coal-fired EGUs	Hg (ounces)	Annual (cumulative)	Yes[a]

[a] The cumulative annual tons of SO_2, the cumulative annual or ozone season tons of NO_x , or the cumulative annual ounces of Hg emitted must be less than or equal to the number of emission credits (allowances) held

[b] At present, CO_2 is not a regulated pollutant. Title IV of the Clean Air Act requires only an estimate of annual CO_2 mass emissions from electrical generating units.

[c] Under 40 CFR Part 76, certain coal-fired units are required to meet an annual NO_x emission limit.

[d] If a unit exceeds its annual NO_x emission rate limit under Part 76, the cumulative annual heat input is used to calculate the excess emission penalty

[e] The ozone season extends from May 1st through September 30th

[f] Heat input monitoring is required for most, but not all NO_x Budget Trading Program sources. Heat input data is used by affected sources to calculate NO_x mass emissions and may be used by State agencies to determine future NO_x allowance allocations.

[g] Required only for coal-fired units and certain oil-fired units in the Acid Rain Program.

[h] Varies according to State and/or other Federal requirements

reported for allowance accounting purposes, but does not require compliance with NO_x emission limits in lb/mmBtu. For sources subject to both the ARP and the NBP, the requirements of both programs must be met—therefore, NO_x mass emissions and NO_x emission rate must both be monitored and reported.

1.3 What is a cap and trade program?

A cap and trade program is a market-based approach to reducing emissions. The concept is simple: EPA caps, or limits, the total annual or seasonal mass emissions of a pollutant such as SO_2, NO_x or Hg. The cap is divided into emission allowances that are allocated to each affected source. Each emission allowance represents an authorization to emit one ton of SO_2 or NO_x, or one ounce of Hg over a specified time period (i.e., calendar year or ozone season). To demonstrate compliance, a source is required to hold a number of allowances greater than or equal to its emissions in the regulated time period. Since the total number of allowances allocated to the affected sources is less than the pre-program ("baseline") mass emissions from those sources, the program reduces the mass emissions of the regulated pollutant..

> A cap and trade program does not specify traditional numerical emission limits (e.g. ppm, lb/mmBtu, etc.) for the regulated pollutant(s) Instead, compliance is demonstrated by holding enough allowances to cover the total mass emissions from the affected unit(s) during a specified time period. However, numerical emission limits imposed by other programs or by the operating permit still apply.

At the end of each compliance period, a reconciliation process takes place to verify that each affected source has enough allowances to cover its emissions. Automatic penalties for noncompliance are part of the U.S. cap and trade programs. For example, if an ARP unit does not have enough allowances to cover its annual SO_2 emissions, the owner or operator of the unit must pay an excess emissions penalty and must surrender future-year allowances to cover the shortfall. For a NBP unit, if its ozone season NO_x emissions exceed its allowance holdings, the owner or operator of the unit must surrender at least 3 future-year allowances and, if required by state rules, pay additional penalties.

This market-based approach allows sources to determine the most cost-effective way to comply. Sources may reduce emissions by using pollution control technologies, employing energy conservation measures, reducing utilization, switching fuels, or other strategies. Sources also are allowed to buy and sell allowances from each other to ensure that each unit has enough allowance credits in its account to cover its emissions. In this manner, a cap and trade program reduces emissions at a lower cost than traditional pollution control regulations and policies, by setting a goal and allowing market forces to determine how the goal is met.

1.4 Why is continuous monitoring necessary?

Emissions monitoring and accounting are the backbone of cap and trade programs. Because the emission allowances are based on the total mass of a pollutant emitted over a certain time period, emissions must be monitored continuously during the compliance period. It is therefore essential to have a reliable measurement method for the commodity being regulated and traded---in this case, emissions— to ensure that the goal of achieving actual, measurable emissions reductions in a cost-effective manner is met. Part 75 provides the necessary measurement method, and gives value to the traded commodity by:

- Ensuring that the emissions from all sources are consistently and accurately measured and reported. In other words, a ton of emissions[2] from one source is equal to a ton of emissions[2] from any other source;

- Ensuring that a complete record of emission data is produced for each unit in the program (i.e., data are obtained for every hour of unit operation);

- Verifying that emission caps are not exceeded, thereby ensuring that emissions are not underestimated and that emission reduction goals are being met.

1.5 How is the Part 75 Rule Structured ?

Part 75 consists of nine Subparts, A through I, followed by a series of eleven Appendices, A through K[3]. A brief description of each Subpart and Appendix follows.

Subparts

- **Subpart A (§§75.1-75.8)** defines the purpose of the regulation and the extent of its applicability. Subpart A also includes general Acid Rain Program provisions, compliance dates, prohibitions, and lists various methodologies (e.g., ASTM, ASME, etc.) that are incorporated into the rule by reference.

- **Subpart B (§§75.10–75.19)** presents the general emission monitoring requirements for each pollutant (SO_2 , NO_x , etc.). Special instructions are given for monitoring at common stack and multiple stack exhaust configurations.

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[2] Or an ounce of emissions, for Hg

[3] Note that three of the Appendices (H, I, and J) are "reserved". Appendix H was in the original January, 1993 rule, but was removed and reserved in May, 1999. Appendix I was proposed in 1998, but never finalized. Appendix J was removed and reserved in May, 1999.

- **Subpart C (§§75.20-75.24)** presents the process for certification and recertification of the required continuous monitoring systems, provides the quality assurance and quality control (QA/QC) requirements for the systems, defines “out-of-control” periods, and requires bias adjustment of data from SO_2 , NO_x , and flow monitors.

- **Subpart D (§§75.30-37)** describes the missing data procedures that are used to determine the appropriate substitute data values, for unit operating hours in which the monitoring systems fail to provide quality-assured data.

- **Subpart E (§§75.40-75.48)** describes the requirements that must be met for approval of an alternative monitoring system.

- **Subpart F (§§75.50-75.59)** contains the recordkeeping requirements

- **Subpart G (§§75.60-75.67)** contains the reporting requirements. Instructions are provided for submitting notifications, monitoring plans, certification applications, emissions reports, and special petitions to the Administrator.

- **Subpart H (§§75.70-75.75)** describes the NO_x mass emission monitoring requirements for sources in a NO_x mass emissions reduction program that adopts Part 75, such as the NO_x Budget Program or a NO_x trading program under the CAIR rule. Special instructions are provided for sources that report data only during the ozone season.

- **Subpart I (§§75.80-75.84)** describes the Hg mass emission monitoring requirements for sources in a Hg mass emissions reduction program that adopts Part 75, such as a national Hg trading program under the CAMR rule.

Appendices

- **Appendix A** describes CEMS installation and certification test procedures, and provides performance specifications for the CEMS and explains how to set the span and range of CEMS ;

- **Appendix B** describes the required on-going CEMS quality assurance tests and procedures for CEMS, and includes rules for data validation;

- **Appendix C** provides guidelines for parametric and load-based missing data substitution;

- **Appendix D** provides an optional protocol for estimating SO_2 mass emissions and heat input for gas-fired and oil-fired units;

- **Appendix E** provides an optional protocol for estimating NO_x emissions from gas-fired and oil-fired peaking units;

- **Appendix F** provides equations for converting raw monitoring data into the appropriate units of measure;

- **Appendix G** gives procedures for monitoring and calculating CO_2 mass emissions, for ARP units;

- **Appendices H, I and J** are currently reserved; and

- **Appendix K** provides special operating instructions and quality-assurance requirements for sorbent trap monitoring systems, which are used to monitor Hg emissions.

1.6 What other Federal regulations interface with Part 75 ?

Part 75 is one of the Acid Rain Program core rules, which, collectively, are found in Volume 40 of the CFR, Parts 72 through 78. Part 75 is referenced in several of the other core rules. First, in §72.2, there are numerous important definitions that apply to Part 75. Second, Part 76, which specifies annual NO_x emission limits for certain coal-fired boilers, requires Part 75 monitoring to be used to demonstrate compliance with these emission limits. Third, Part 74 requires units that opt-in to the Acid Rain Program to monitor and report SO_2 emissions according to Part 75.

Part 75 also interfaces with some of the New Source Performance Standards (NSPS) regulations in 40 CFR Part 60. Many units that are currently in the Acid Rain Program or the NO_x Budget Program are also subject to one of the NSPS boiler regulations (Subparts D, Da, Db and Dc) or to the NSPS rule for combustion turbines (Subpart GG). The Part 60 boiler regulations require continuous emission monitoring for SO_2 and/or NO_x , and Subpart GG allows a NO_x CEMS to be used to monitor and report "excess emissions". Subparts Da and Db allow a certified Part 75 NO_x monitoring system to be used to meet the Part 60 NO_x monitoring requirements. Subpart GG allows a certified Part 75 NO_x CEMS to be used for excess emission monitoring.

2.0 OVERVIEW OF PART 75 MONITORING REQUIREMENTS

Part 75 requires an hourly accounting of the emissions from each affected unit. Continuous emission monitoring systems (CEMS) are used to provide the emissions data unless the unit qualifies to use one of the alternative monitoring methodologies specified in the rule. With few exceptions, the alternative methodologies apply to oil-fired and gas-fired units.

The selected monitoring methodology for each unit must be approved by EPA through a certification process. Once the methodology has been approved and the required monitoring systems are certified, the recording and reporting of emissions data begins. Part 75 also requires on-going quality assurance and quality control (QA/QC) procedures, to ensure that the data collected by the monitoring systems continue to be accurate.

This section provides an overview and general description of the Part 75 monitoring and reporting requirements (see Figure 1). More specific information is provided in the subsequent sections of this guide.

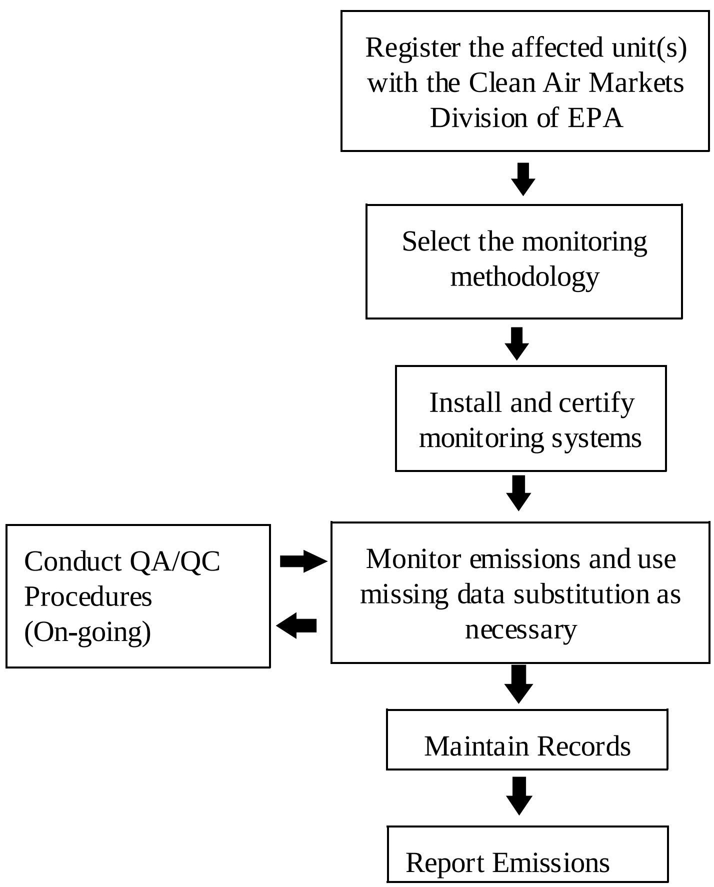

Figure 1. Overview of Part 75 Monitoring Requirements

2.1 Register the Affected Unit(s) with EPA.

Each affected unit must be registered with EPA's Clean Air Markets Division (CAMD) before any data is reported for the unit. As part of the registration process, a Designated Representative, or "DR" (for the Acid Rain and CAIR Programs), a "Hg Designated Representative" (for the CAMR Program), or an Authorized Account Representative, or "AAR" (for the NO_x Budget Program), must be assigned for each unit. The Designated Representative or AAR takes the responsibility for ensuring that each affected unit complies with all of the applicable program requirements, and that the emissions data reported to EPA are true and accurate. For units subject to both the Acid Rain Program and to one or more of the SO_2 and NO_x trading programs under CAIR, the Designated Representative for all of these trading programs must be the same person.

2.2 Select a Monitoring Methodology

Monitoring Options

Part 75 provides several monitoring options. The options that are available for a unit depend on how the unit is classified (see Table 2 in Section 2.4, below). In general, if a unit is coal-fired or combusts any type of solid fuel, the basic continuous monitoring provisions in §§75.10-75.18 require the use of CEMS for all monitored parameters. However, there are a few exceptions to this. If a unit is classified as an oil- or gas-fired unit, it may qualify for an alternative monitoring approach instead of CEMS for some or all parameters. In some cases, the unit may even qualify for a monitoring exemption.

> The Part 75 rule generally requires the use of CEMS for units that combust coal or other solid fuel(s). Alternative monitoring approaches, referred to in the rule as "excepted methods" or "excepted monitoring systems" , may be used for qualifying oil-fired and gas-fired units, and for certain coal-fired units under the CAMR rule.

The monitoring alternatives or exemptions that apply to a unit depend mainly on how often the unit operates each year, how much it emits, and the type(s) of fuel(s) it combusts. These alternatives and exemptions are:

- ***Any oil-fired or gas-fired unit*** may use the alternative, or "excepted" methodology in Appendix D of Part 75 to determine SO_2 mass emissions and/or unit heat input. The Appendix D method requires continuous monitoring of the fuel flow rate with a certified fuel flowmeter and periodic fuel sampling and analysis to determine one or more of the following quantities: (1) the gross calorific value (GCV) of the fuel; (2) the fuel sulfur content; and (3) the density of the fuel. The Appendix D methodology is discussed in greater detail in Section 4 of this guide.

- ***Oil-fired and gas-fired peaking units*** may use the alternative method in Appendix E of Part 75 to estimate the hourly NO_x emission rate in lb/mmBtu. Appendix E requires hourly determination of the heat input rate to the unit, using the fuel flow rate measured by a certified Appendix D fuel flowmeter, in conjunction with the GCV of the fuel. A correlation curve of NO_x emission rate versus heat input rate (derived from emission testing) is then used to estimate the hourly NO_x emission rates. The Appendix E methodology is discussed in greater detail in Section 5 of this guide.

- ***Certain oil-fired and gas-fired units*** may qualify to use the low mass emissions (LME) methodology in §75.19 to estimate SO_2, CO_2, and/or NO_x emissions and heat input. To qualify for LME status, a unit's annual SO_2 and NO_x mass emissions, and in some cases, its ozone season NO_x mass emissions, must be demonstrated to be below certain threshold values.

  The LME methodology requires that records be kept of the hours in which the unit operates, the type(s) of fuel(s) combusted, the electrical or steam load during each of those hours, and, in some cases, the operational status of the NO_x emission controls. Default emission rates and estimates of heat input are used to quantify the unit's mass emissions. The LME methodology is discussed in greater detail in Section 6 of this guide.

- ***Acid Rain Program units*** may use the alternative procedures in Appendix G of Part 75 to estimate CO_2 mass emissions, in lieu of installing CEMS. Appendix G allows CO_2 emissions to be estimated, either by using: (1) fuel feed rates and the results of periodic fuel sampling and analysis (to determine the % carbon in the fuel); or (2) hourly heat input rate measurements from a certified Appendix D fuel flowmeter and a fuel-specific, carbon-based "F-factor".

  Appendix G is the most frequently-used method for estimating CO_2 mass emissions from oil and gas-fired units. Part 75 allows the fuel feed rate methodology (option (1), above) to be used for coal-fired units also, but it is not currently being used by any of them.

- ***Certain Acid Rain Program units*** are exempted from opacity monitoring requirements. Coal-fired units with wet scrubbers may be exempted if the presence of condensed water in the effluent gas stream interferes with the opacity readings. Also, any unit that meets the definition of gas-fired or diesel-fired in §72.2, or that qualifies as a dual-fuel reciprocating engine is exempted from opacity monitoring. However, note that these Part 75 exemptions do not supersede the provisions of any other program, regulation, or permit that may require an opacity monitor to be installed.

- ***Affected coal-fired units under the CAMR rule*** may use an alternative ("excepted") type of continuous Hg monitoring system, known as a "sorbent trap monitoring system". A sorbent trap system continuously samples the stack gas for an extended period of time (e.g., up to a week or more) and collects Hg on a sorbent medium such as activated carbon. The total volume of stack gas sampled during the collection period is measured, and the Hg concentration is determined by taking the ratio of the collected Hg mass to the sample volume.

- ***Certain affected units under CAMR*** may qualify to use a low mass emissions methodology to estimate the annual Hg mass emissions, in lieu of continuously monitoring the Hg concentration. This alternative methodology applies mainly to small units with very low ($\leq$ 29 lb/yr) annual Hg mass emissions. It requires periodic Hg emission testing, and conservatively high default Hg concentrations must be used for emissions reporting.

Sections 3 through 6 of this guide provide more information on the various Part 75 emission monitoring methodologies. Section 3 describes the basic CEM provisions, and Sections 4, 5, and 6, respectively, discuss the alternative Appendix D, Appendix E, and low mass emission methodologies.

Special Petitions

Under §75.66, EPA has established a petition process through which affected sources can request relief or variances from certain provisions of Part 75. Each petition must contain sufficient information for the Agency to evaluate the request. At a minimum, the petition must: (1) identify the affected facility and unit(s); (2) explain why the proposed alternative is being suggested instead of the regulatory requirement; (3) provide a description of any equipment or procedures used in the proposed alternative; (4) demonstrate that the proposed alternative is consistent with the purposes of Part 75 and the Clean Air Act; and (5) explain why approving it will not have any significant adverse effects.

The regulatory flexibility provided by the petition process reduces the cost of compliance for many sources and facilitates program implementation. EPA strives for consistency in its petition responses. When a petition is approved (or denied), petitions of a similar nature will also be approved (or denied). The Agency also seeks to avoid setting precedents by answering petitions in a way that will weaken or undermine the Part 75 rule. Finally, when EPA approves a large number of petitions of the same type, this often indicates the need for a rule change. The Agency has revised Part 75 a number of times on this basis.

Alternative Monitoring Systems

Subpart E of Part 75 allows sources to petition EPA for approval of an alternative

> On the one hand, EPA has received and approved only a few Subpart E petitions to use alternative monitoring systems, partly due to the rigorous requirements of Subpart E and partly because the Appendix D, Appendix E and LME "excepted" methods in Part 75 provide substantial flexibility in choosing a monitoring methodology. On the other hand, the Agency has approved many minor variations to the monitoring provisions of Part 75

monitoring system. To obtain approval, the petition must demonstrate that the alternative system has the same precision, reliability, accessibility, and timeliness as a certified Part 75 CEMS. The performance of any alternative system must be demonstrated by simultaneous testing against a fully certified CEMS or an EPA reference test method. The petition must also propose quality assurance procedures and missing data substitution procedures for the alternative monitoring system that are consistent with the corresponding Part 75 procedures for CEMS. The criteria and procedures for approval of alternative systems are specified in Subpart E and are not discussed further in this guide.

2.3 Install and Certify Monitoring Systems

Before any monitoring methodology or monitoring system is used, it must be approved through a certification process. This process is described in detail in Section 7 of this guide. Except for LME units[4], the general steps for obtaining certification are:

- Step 1---Prepare and submit an initial monitoring plan
- Step 2---Submit certification test notices
- Step 3---Conduct certification testing
- Step 4---Submit a certification application
- Step 5---Receive approval or disapproval

2.4 Monitor and Record Emissions Data

With the exception of LME units[5], monitoring and reporting of emissions begins as soon as certification testing is successfully completed, provided that the tests are completed by the

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[4] For LME units, only the first, fourth, and fifth steps of the process apply. The initial monitoring plan and the certification application are submitted together ≤45 days before the methodology begins to be used (see Section 6 of this guide).

[5] For LME units, reporting begins with the first operating hour in the year or ozone season in which the LME methodology is first used (see Section 6 of this guide for further discussion). This date will always be later than the date of provisional certification (which in this case, is the date that a complete certification application is received—see §75.20(h)(3)).

certification deadline specified in the regulations[6]. Part 75 monitoring systems are considered to be "provisionally certified" in the period extending from the date of successful completion of the

Table 2: Part 75 Monitoring Options

If an Affected Unit Is Classified as a . . .	These are the Allowable Monitoring Options ...					
	Basic CEMS Provisions[a] (§§75.10-18)	Appendix D Method[b]	Appendix E Method[c]	LME Method[d] (§75.19)	Appendix G Method[e]	Excepted Hg Method[f]
Coal-fired unit under ARP, NBP, or CAIR	✓				✓	
Coal-fired unit under CAMR	✓					✓
Non-peaking oil-fired or gas-fired unit under ARP, NBP, or CAIR	✓	✓		✓	✓	
Oil-fired or gas-fired peaking unit under ARP, NBP, or CAIR	✓	✓	✓	✓	✓	

[a] For SO_2, NO_X, CO_2, flow rate, Hg, opacity, and heat input (as applicable).
[b] For SO_2 emissions and heat input only.
[c] For NO_X emissions only. If Appendix E is used for NO_x, Appendix D must be used for SO_2 and/or heat input.
[d] If the LME qualifying thresholds are met and this method is selected, it must be used for all parameters, i.e., for SO_2, NO_X, CO_2, and heat input (as applicable)
[e] For CO_2 emissions only
[f] Any affected unit under CAMR may use an "excepted" sorbent trap monitoring system instead of an Hg CEMS (see §§72.2 and 75.15). Low-emitting sources of Hg (≤ 29 lb/yr) may qualify to use the excepted mercury low mass emissions methodology described in §75.81(b).

[6] When the tests are not completed by the deadline, emissions reporting must begin immediately upon expiration of the deadline, and conservatively high substitute data values (usually maximum potential values) must be reported.

certification tests[7] through the end of a 120-day review period[8], provided that the systems are operated in accordance with all Part 75 requirements and the permitting authority does not disapprove the systems in the meantime. Emissions data may be reported as quality-assured during this period of provisional certification.

Part 75 requires emissions data to be reported for every hour that an affected unit is operating, including periods of start-up, shutdown, and malfunction. If one of the required monitoring systems is not working or is out-of-control (e.g., if it fails one of its required quality assurance tests), data from an approved backup monitor or from an EPA reference method[9] may be reported. If quality-assured data from a back-up monitor or reference method are not available, the Part 75 missing data substitution procedures must be used to estimate emissions.

The Part 75 missing data routines for CEMS are found in §§75.31 through 75.38 and the routines for sorbent trap monitoring systems are found in §75.39. These routines consist of mathematical algorithms that are used to determine an appropriate substitute value for any unit operating hour in which quality-assured data are not obtained for a monitored parameter (i.e., for SO_2 , NO_x, Hg, CO_2, O_2 , flow rate, or moisture). Generally speaking, historical, quality-assured monitoring data are used to determine the substitute data values. The exact substitute data values that are applied in a given situation depends on:

- The historical availability of quality-assured data from the monitor(s)[10];
- The length of the missing data period; and
- For certain parameters (NO_x and flow rate), the hourly unit loads during the missing data period.

The missing data procedures are designed to be conservative. This provides an incentive to reduce periods of monitor downtime, by rewarding high percent monitor data availability (PMA)[10]. The procedures will produce conservatively high emissions estimates for units with

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[7] Note that when "conditional data validation" is used, the date of provisional certification may be date on which certification testing begins (or perhaps even earlier), rather than the date on which the testing is completed (see Section 9.5 of this guide).

[8] Upon receipt of a complete certification application, the regulatory agencies have 120 days to review the application. A notice of approval or disapproval may be issued during this time period. Absent such notice, if all required tests were passed, the monitoring systems are considered to be certified "by default".

[9] EPA reference methods are discussed in Section 7.7 of this guide.

[10] The term used in Part 75 to describe this is the "percent monitor data availability", or PMA. In its most basic form, the PMA represents the percentage of time that quality-assured data was obtained in a historical lookback through a certain number of unit operating hours. Note that the PMA tracks the availability of quality-assured data, not the availability of individual monitoring systems. For example, if the primary CEMS is out-of-service but quality-assured data are recorded by a backup system, the PMA is unaffected.

lower PMA values.

The monitoring methodologies in Appendices D, E, and G of Part 75 also have missing data procedures. The missing data algorithms under these appendices are considerably less complex than the CEMS and sorbent trap system algorithms. The Part 75 missing data substitution procedures are discussed in greater detail in Section 9 of this guide.

2.5 Conduct Quality Assurance/Quality Control Procedures

After certification, the following periodic performance evaluations of all monitoring systems must be conducted, to ensure the continued accuracy of the emissions data:

- The quality-assurance tests for CEMS include daily assessments (e.g., calibration error tests), weekly assessments (system integrity checks of Hg CEMS equipped with converters), quarterly assessments (e.g., linearity checks), and semi-annual (or annual in some cases) relative accuracy test audits (RATAs);

- For sorbent trap monitoring systems, annual RATAs and the quality assurance procedures of Part 75, Appendix K are required;

- For CAMR units that qualify to use the Hg low mass emissions option, either semi-annual or annual Hg emission testing is required, depending on the annual mass emission level;

- For Appendix D fuel flowmeters, annual accuracy tests are required; and

- For Appendix E units and LME units using site-specific emission rates, re-testing is required once every 5 years.

Note that for linearity checks, RATAs, and fuel flowmeter accuracy tests, test exemptions and test deadline extensions are permitted by Part 75 in certain circumstances. The required QA tests for Part 75 monitoring systems are discussed in greater detail in section 8 of this guide.

For all required continuous monitoring systems, a written quality assurance (QA) plan must be developed and followed . The quality control plan includes step-by-step procedures for each of the required QA tests, as well as procedures for calibration adjustments, preventive maintenance, audits, recordkeeping and reporting.

2.6 Maintain Records

The basic record keeping provisions of Part 75 are found in Subpart F (§75.53 and §§75.57 through 75.59). Most of the required records are kept electronically, for a minimum of three years, using a data acquisition and handling system (DAHS), although some monitoring plan information and quality assurance (QA) test support data is kept in hard copy. The DAHS records all data from the monitoring systems, translates it into the required units of measure, and stores the data. When emissions data are missing, the DAHS automatically performs missing data substitution. The DAHS also electronically records and stores operating data for the combustion unit, emission control device data, monitoring plan data, and the results of QA checks and tests.

Parallel recordkeeping sections, that frequently cite the basic Subpart F provisions, are found in §75.73 of Subpart H (for NO_x mass trading programs such as the NBP) and in §75.84 of Subpart I (for mercury mass trading programs such as the CAMR). The NBP, CAIR and CAMR rules also include recordkeeping sections, but in general, these sections contain no new or unique requirements. Rather, they serve as “road signs”, pointing back to the recordkeeping provisions in Subparts F, H, and I.

The electronic records that must be maintained are quite detailed and are not discussed further in this guide. Typically, DAHS vendors can provide software that meets the Part 75 recordkeeping requirements.

2.7 Report Emissions

The basic Part 75 reporting provisions (originally written for the ARP) are found in Subpart G (§§75.60 through 75.64). Subpart G includes requirements to provide various types of notifications and to submit monitoring plans, certification applications, and electronic emissions reports at specified times. Parallel notification and reporting sections, which reference sections of Subpart G, are found in §§75.73 and 75.74 of Subpart H (for NO_x trading programs such as the NBP), and in §75.84 of Subpart I (for mercury trading programs such as the CAMR).

The NBP, CAIR and CAMR rules also include notification and reporting sections, but these sections simply reference the notification and reporting provisions in Subparts G, H, and I of Part 75. The CAIR SO_2 rule refers to Subpart G; the NBP and CAIR NO_x rules refer to Subparts G and H; and the CAMR rule refers to Subpart I.

For units under the Acid Rain Program and/or the CAIR annual SO_2 and NO_x trading programs, emissions reports must be submitted four times a year, i.e., one report for each calendar quarter. Units that are subject to the NO_x Budget Program or to the CAIR ozone season NO_x trading program, but are <u>not</u> in either the Acid Rain Program or the CAIR annual SO_2 and NO_x programs, have the option of reporting emissions data either year-round or only for the ozone season (May 1st through September 30th).

The quarterly reports allow EPA to track the quality of the emissions data throughout the year (or ozone season) as well as the status of emissions compared to the allowances held. The data and information to be reported include the following:

- Facility information;

- The hourly emissions data, operating data, the results of the required QA tests, and other information specified in the monitoring plan and recordkeeping sections of Part 75;
- Unit operating hours for the quarter and cumulative operating hours for the calendar year and/or ozone season;
- Tons of SO_2 emitted during the quarter and cumulative SO_2 mass emissions for the calendar year (ARP units and units in the CAIR SO_2 Trading Program, only);
- Average NO_x emission rates (lb/mmBtu) for the quarter and for the year-to-date (ARP units, and certain units in the NBP and CAIR NO_x Trading Programs);
- Tons of CO_2 emitted during the quarter and cumulative CO_2 mass emissions for the calendar year (ARP units, only);
- Tons of NO_x emitted during the quarter and cumulative NO_x mass emissions for the calendar year and/or ozone season, as applicable (for units in the NBP and CAIR NO_x Trading Programs);
- Ounces of Hg emitted during the quarter and cumulative Hg mass emissions for the calendar year (CAMR units, only); and
- Total heat input (mmBtu) for quarter and cumulative heat input for calendar year (or ozone season)—unless exempted from heat input reporting by regulation.

EPA requires the data be submitted electronically, because of the large volume of information that must be reported. The Agency provides a standard electronic data reporting (EDR) format that must be used and provides monitoring data checking (MDC) software that can be used to perform quality control checks on the data prior to data submittal. While use of the MDC software is optional, EPA encourages it because using the MDC will cut down on the number of re-submissions and save time and money. EPA processes each quarterly report through rigorous quality control checks to verify data accuracy and conformance to the required format. After the review, the Agency sends notifications to the affected sources, indicating whether the quarterly data are acceptable or unacceptable. The Part 75 reporting requirements are discussed in more detail in Section 10 of this guide.

3.0 BASIC CONTINUOUS EMISSION MONITORING REQUIREMENTS

The basic Part 75 continuous monitoring approach is to install CEMS and a DAHS on each affected unit and record emissions and heat input data. This general approach must be followed for combustion units that burn coal or any other solid fuel[11] (see Table 3). Oil-fired and gas-fired units may either comply with these basic requirements or may use alternative monitoring methods for some or all parameters (see Sections 4, 5, and 6 of this guide for further discussion of the alternative methods).

Table 3: Units that Must Comply with the Basic Part 75 CEMS Requirements

The basic Part 75 CEMS requirements must be met for any unit that . . .
• Is coal-fired, as defined in §72.2; or that • Combusts wood, refuse or other material in addition to gas or fuel oil

3.1 What is a continuous emission monitoring system (CEMS)?

A continuous emission monitoring system, or CEMS, consists of all the equipment needed to measure and provide a permanent record of the emissions from an affected unit. Examples of CEMS components include:

- Pollutant concentration monitors (e.g., SO_2 , NO_x, or Hg monitors).
- Diluent gas monitors, to measure $\%O_2$ or $\%CO_2$
- Volumetric flow monitors
- Sample probes
- Sample (“umbilical”) lines
- Sample pumps
- Sample conditioning equipment (e.g., heaters, condensers, gas dilution equipment)
- Data loggers or programmable logic controllers (PLCs)

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[11] As previously-noted, Part 75 allows the use of Appendix G, a non-CEMS method, to estimate CO_2 mass emissions from coal-fired units. However, none of the coal-fired units in the Acid Rain or NO_x Budget Programs are presently using it. Also, for Hg, certain coal-fired may qualify to use the low mass emissions option in §75.81(b), instead of continuously monitoring the Hg concentration.

- DAHS components that electronically record all measurements and automatically calculate and record emissions and heat input in the units of measure required by the rule.

The specific components of a CEMS depend upon the parameter being monitored, the measurement principle of the CEMS, and the required units of measure. Some components are common to all systems, while others are specific to a particular monitoring technology. To illustrate:

- The key components of every Part 75 CEMS are the analyzer(s) and the DAHS (see Table 4). Table 4 shows that all Part 75 CEM systems, except for one, have only one component monitor. The exception is the NO_x emission rate, or "NO_x-diluent" monitoring system, which measures NO_x in lb/mmBtu. This system includes both a NO_x monitor and a diluent gas monitor (either CO_2 or O_2).

- PLCs and data loggers are common to all types of CEMS

- Probes, sample lines, vacuum pumps and sample conditioning equipment are associated with "extractive" CEMS, which continuously withdraw a sample of the effluent gas from the stack and send it to an analyzer located in a climate-controlled environment (i.e., a "CEMS shelter").

- "In-situ" CEMS, which analyze the effluent gas at stack conditions, sometimes have probes[12], but unlike extractive systems, do not require sample lines, sample conditioning equipment, etc.

- Extractive CEMS that measure on a dry basis require moisture removal systems, whereas wet basis extractive systems[13] do not.

The number of required monitors can sometimes be minimized by sharing certain components among two or more monitoring systems. For example, data from a single diluent gas monitor could be used to calculate NO_x emission rate and CO_2 mass emissions.

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[12] Some in-situ monitoring systems have a probe that measures at a single point or along a short path. Other in-situ systems send a beam of light across the stack to a detector.

[13] There are two basic types of wet-basis extractive systems: (1) hot-wet; and (2) dilution extractive. Hot-wet systems (which are seldom used) require the sample lines and the analyzer to be heated to prevent moisture from condensing. Dilution-extractive systems (which are widely-used in Part 75 applications) prevent condensation by a different principle. The gas sample is diluted with large quantities of purified air to keep it above its dew point.

Table 4: Part 75 CEM Systems

Type of Monitoring System (Units of Measure)	Key Components:							
	SO_2 Monitor	NO_x Monitor	Flow Monitor	Diluent Gas[a] Monitor	Hg Monitor[g]	Moisture Monitor	Opacity Monitor	DAHS
SO_2 concentration (ppm)	√							√
NO_x emission rate (lb/mmBtu)		√		√				√
NO_x concentration[b] (ppm)		√						√
Hg concentration (µg/scm)					√			√
Stack gas flow rate (scfh)			√					√
CO_2 concentration[c] (% CO_2)				√				√
O_2 concentration[d] (% O_2)				√				√
Moisture[e] (% H_2O)						√		√
Opacity[f] (%)							√	√

[a] Diluent gas is either CO_2 or O_2.

[b] This type of system is used only by NO_x Budget Program or CAIR NO_x Program sources, in conjunction with a stack flow monitor, to quantify NO_x mass emissions.

[c] Note that CO_2 concentration may be determined indirectly, using an O_2 monitor and Equation F-14a or F-14b. In the Acid Rain Program, this type of system is used with a flow monitor to quantify CO_2 mass emissions. In the NO_x Budget Program or CAIR NO_x Program, it is used exclusively for heat input rate determinations.

[d] This type of system is used exclusively for heat input rate determinations. An O_2 monitor is required.

[e] This type of system is used whenever the emissions or heat input calculations require a correction for the stack gas moisture content.

[f] This type of system is required only for coal-fired and certain oil-fired units in the Acid Rain Program. It is generally referred to as a “continuous opacity monitoring system”, or “COMS”, rather than a CEMS.

[g] A sorbent trap monitoring system may be used to monitor the Hg concentration, in lieu of a Hg CEMS.

3.2 What is a sorbent trap monitoring system ?

As previously noted in Section 2.2, above, a sorbent trap monitoring system is an alternative type of continuous Hg monitoring system that may be used instead of an Hg CEMS, for any affected unit under the CAMR rule. A sorbent trap system continuously samples the stack gas for an extended period of time (anywhere from several hours to several days, depending on the Hg concentration in the stack). Mercury is collected inside a tube ("trap") that is filled with a sorbent medium such as activated carbon, and a dry gas meter is used to measure the total volume of dry stack gas sampled during the data collection period.

The sorbent trap system is similar to an extractive-type CEMS, in that it continuously samples the stack gas and uses a moisture removal system. However, the similarity ends there, as the sorbent trap system differs from a CEMS in many ways. First, it does not measure the real-time Hg concentration every hour. Rather, it gives only an average Hg concentration over the data collection period, and this average concentration cannot be known until the sorbent traps have been analyzed in the lab. Second, unlike a CEMS, which samples at a constant rate, the sample flow rate through a sorbent trap is varied during the collection period, in proportion to the stack gas volumetric flow rate. Third, paired sorbent trap systems must be run simultaneously during each data collection period, and the Hg concentrations obtained from the two systems must agree to within a specified tolerance to validate the data. Finally, the certification and on-going quality-assurance test requirements for sorbent trap systems are considerably different from those for an Hg CEMS. The only QA test common to both types of systems is the RATA. The certification and QA test requirements for Hg monitoring systems are discussed further in Sections 7 and 8 of this guide.

3.3 Primary and Backup Monitoring Systems

For each monitored pollutant or parameter, Part 75 requires that a primary monitoring system be designated. Data from the primary system <u>must</u> be reported if it is in-service. However, when the primary system is not able to provide quality-assured data, data from one of the following types of backup monitors or monitoring systems may be reported:

- ***Redundant backups***. A redundant backup monitoring system is a fully-certified, stack- or duct-mounted system that continuously records data and is kept on "hot stand-by" in case of a primary system outage. A redundant backup monitoring system is operated, maintained and quality-assured in the same manner as the primary system.
- ***Non-redundant backups***. A non-redundant backup monitoring system is a certified system that does not operate continuously. Rather, it is kept on "cold stand-by", and must pass a substantive quality-assurance test each time it is brought into service. For example, before a non-redundant backup gas monitoring system can be used for Part 75 reporting, it must pass a linearity check. The use of a non-redundant backup system is restricted to 720 hours per year at a given unit or stack location.

- ***Like-kind replacement analyzers***. A like-kind replacement analyzer is a gas analyzer of the same type as the primary (i.e., it monitors the same parameter by the same measurement principle). A like-kind replacement analyzer may be used for short periods of time when the primary analyzer malfunctions or needs maintenance. The replacement analyzer does not require certification, provided that it is connected to the same probe and sample interface as the primary analyzer, and that it is not used for more than 720 hours per year at a particular unit or stack location. A linearity check of the analyzer is required each time it is brought into service.
- ***Reference method backups***. EPA reference test methods (e.g., Method 6C for SO_2 or Method 7E for NO_x) may be used to provide quality-assured data during CEMS outages.

Although it might save money initially, failure to have backup or redundant monitoring equipment could result in over-reporting of emissions in the long run. For example, suppose that the same CO_2 monitor is used to determine both CO_2 mass emissions and NO_x emission rate. When the CO_2 monitor malfunctions, the missing data procedures for both NO_x and CO_2 must be applied, since the systems for NO_x and CO_2 are considered to be out-of-control. As previously noted, the Part 75 missing data procedures tend to produce increasingly more conservative (i.e., conservatively high) emissions estimates as the PMA decreases. Therefore, long missing data periods may result in significant over-reporting of emissions and loss of allowance credits.

3.4 How must a CEMS be operated?

The minimum operating and data capture requirements for Part 75 CEM systems are summarized in Table 5. In general, the CEMS must be operated at all times when the unit is combusting fuel, except when the monitors are being calibrated, maintained, or repaired. As previously noted, each CEMS must be equipped with an automated DAHS, to record the emissions data and to reduce it to hourly averages[14]. To make an hourly average, at least one valid data point (generally, this means a valid one-minute average) is required in each 15-minute quadrant of the hour in which the unit operates.[15] A single DAHS is usually sufficient to manage data for all the parameters that must be monitored.

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[14] Except for opacity data, which generally has a shorter averaging period (e.g., 6 minutes)

[15] However, when required quality-assurance or maintenance activities are performed during a unit operating hour, only two data points (in two separate quadrants, $\geq$ 15 minutes apart) are needed to validate the hourly average. This helps to minimize data loss during mandatory QA activities.

Table 5: Minimum Operating and Data Capture Requirements for Part 75 CEMS

For this parameter...	The CEMS must complete one cycle of sampling and analyzing at least...	And record valid data at least...	And the DAHS must reduce the recorded data to...
SO_2, CO_2, O_2, NO_x, Hg, moisture, and flow rate	Once for each successive 15-minute period	Once for each 15-minute "quadrant" in each unit operating hour	Hourly averages
Opacity	Once for each successive 10-second period	Once for each successive averaging period	6-minute averages or other required averaging period

3.5 How are emissions and heat input rates determined from CEMS data?

The methods for determining emissions and heat input rates are shown in Table 6. This table presents the general equations used to convert monitoring data into the units of measure required by Part 75. The equations are somewhat different for each parameter monitored, but are based on the same principles. These principles are explained below.

The gas monitors required by Part 75 (i.e., SO_2 , NO_x , CO_2 and O_2) measure concentration in parts per million by volume (ppmv)[16], with one exception—Hg monitors measure concentration in micrograms per standard cubic meter (µg/scm). However, concentration data alone are not sufficient to characterize emissions under Part 75---the concentrations must be converted into emission rates. The rule specifies the appropriate conversion factors to use.

The units of the emission rates are pounds per standard cubic foot (lb/scf) for SO_2 and NO_x, tons per standard cubic foot (tons/scf) for CO_2, and ounces per standard cubic foot (oz/scf) for Hg. These emission rates are then used to determine the emissions in the units of measure required by Part 75, i.e., either mass per unit of time (lb/hr, tons/hr, or oz/hr), mass per unit of heat input (e.g., lb/mmBtu), or simply mass (pounds, tons, ounces).

[16] Diluent gas monitors give a readout in % CO_2 or %O_2 , but this is simply a power of 10 multiple of the parts per million value, e.g., 10% CO_2 corresponds to 100,000 ppmv.

Table 6: Calculating Emissions and Heat Input Rate from Part 75 CEMS Data

To calculate this quantity. . .	These parameters must be monitored . . .	And an equation with this general structure is used . . .	Example Equations [a]
SO_2 or NO_x mass emission rate (lb/hr) or CO_2 mass emission rate (tons/hr) or Hg mass emission rate (ounces/hr)	SO_2 concentration and stack gas flow rate or CO_2 concentration and stack gas flow rate or Hg concentration and stack gas flow rate	E = (K) * (C) * (Q) *(H_2O) Where: E = SO_2 , NO_x , CO_2 or Hg mass emission rate (lb/hr or tons/hr or ounces/hr) K = Species-specific conversion constant [b] C = Hourly average SO_2 , NO_x , CO_2, or Hg concentration (ppmv or %CO_2, or µg/scm) Q = Hourly average volumetric flow rate (scfh) H_2O = Moisture correction term (if SO_2 , CO_2 , or Hg is measured on a dry basis)	F-1, F-2
SO_2 , NO_x , CO_2 , or Hg mass emissions (lb, tons, or ounces)	SO_2 , NO_x , CO_2 , or Hg concentration, stack gas flow rate and operating time	M = (E) * (t_{op}) Where: E = SO_2 , NO_x , CO_2 , or Hg mass emission rate, calculated as shown above (lb/hr, tons/hr, or ounces/hr) t_{op} = Operating time [c] (hr)	F-3, F-12, F-26, F-28, F-29
NO_x emission rate (lb/mmBtu)	NO_x concentration and Diluent gas (CO_2 or O_2) concentration	R = (K) * (C) * (F) * (D)* (H_2O) Where: R = NO_x emission rate (lb/mmBtu) K = Conversion constant[b] C = Hourly average NO_x concentration (ppmv) F = Fuel-specific F-factor (dscf/mmBtu or scf CO_2/mmBtu) D = Diluent gas correction term H_2O = Moisture correction term (if NO_x and diluent are measured on a different moisture basis)	F-5, F-6, 19-4, 19-8
NO_x mass emissions (lb) (Alternate method)	Heat input rate, NO_x emission rate, and operating time	M = (R) * (HI) * (t_{op}) Where: M = NO_x mass emissions (lb) R = NO_x emission rate (lb/mmBtu) HI = Heat input rate (mmBtu/hr) t_{op} = Operating time [c] (hr)	F-24

Table 6 (cont'd)

To calculate this quantity. . .	These parameters must be monitored . . .	And an equation with this general structure is used . . .	Example Equations [a]
Heat input rate (mmBtu/hr)	Diluent gas concentration and stack gas flow rate	HI = (Q) * (1/F) * (1/D)*(H_2O) Where: HI = Heat input rate (mmBtu/hr) Q = Hourly average volumetric flow rate (scfh) F = Fuel-specific F-factor (dscf/mmBtu or scf CO_2/mmBtu) D = Diluent gas correction term H_2O = Moisture correction term (if required)	F-15, F-16, F-17, F-18
Opacity	Opacity (%)	Follow the site-specific instructions of the instrument manufacturer	-------

a Equation codes beginning with "F" are from Appendix F of Part 75. Equations beginning with "19" are from EPA Method 19, in Appendix A-7 of 40 CFR Part 60.

[b] The appropriate constants are 1.660 x 10^{-7} lb/scf-ppm for SO_2 , 1.194 x 10^{-7} lb/scf-ppm for NO_x , 5.7 x 10^{-7} tons/scf-%CO_2 for CO_2, and 9.978 x 10^{-10} oz-scm/µg-scf for Hg.

[c] Operating time is defined as the fraction of the hour in which the unit operates (or, for a common stack, the fraction of the hour that exhaust gases flow through the stack). For example, t_{op} = 1.00 for a full hour of unit operation, 0.50 for a half-hour of unit operation, etc.

Determining lb/mmBtu emission rates

To obtain emission rates in terms of mass per unit of heat input (e.g., NO_x emission rate in lb/mmBtu), the emission rate in lb/scf is multiplied by a fuel-specific "F-factor." The F-factor relates the volume of stack gas or CO_2 produced by combustion to the caloric heat content of the fuel combusted. For example, typical units for an F-factor are dry standard cubic feet of stack gas per million Btu heat input (dscf/mmBtu), or standard cubic feet of CO_2 per million Btu (scf CO_2 /mmBtu). The F-factors, which are listed in Appendix F of the rule, are derived for each type of fuel based on the thermodynamic principles of combustion. Since F-factors are derived assuming that fuel and air are mixed in an exact stoichiometric ratio and that combustion is complete, corrections for excess air are needed.

Determining mass emission rates

To obtain emission rates in terms of mass per unit time (lb/hr, tons/hr, or oz/hr), the emission rate (lb/scf, tons/scf, or oz/scf) is multiplied by the stack gas flow rate, in standard cubic feet per hour (scfh). For $NO_{x,}$ the mass emission rate in lb/hr may also be calculated by multiplying the NO_x emission rate (lb/mmBtu) by the heat input rate (mmBtu/hr).

Determining heat input rate, in mmBtu/hr

To determine heat input rate (mmBtu/hr), the monitored stack gas flow rate (scfh) is divided by the F-factor (scf/mmBtu) and a correction for excess air is applied.

Converting mass emission rates and heat input rates

To convert an hourly pollutant mass emission rate (e.g., lb/hr) to mass (e.g., lb), or to convert an hourly heat input rate (mmBtu/hr) to heat input (mmBtu), multiply the emission (or heat input) rate by the operating time. The operating time, t_{op}, is defined as the fraction of the hour in which the unit combusts fuel. For units sharing a common stack, if the CEMS are installed on the stack, the operating time is the fraction of the hour that exhaust gases flow through the stack. For example, t_{op} = 1.00 for a full hour of unit operation, 0.50 for a half-hour of unit operation, etc.

3.6 When are corrections for stack gas moisture content required?

Determination of the stack gas moisture content is required only in certain situations where CEMS are used to satisfy the Part 75 monitoring requirements. Table 7 summarizes when correction for the stack gas moisture content is required. Generally speaking, the stack gas moisture content must be monitored when two parameters in the emission or heat input rate equation (e.g., gas concentration and stack gas flow rate) are not measured on the same moisture basis (i.e., one is measured on a wet basis and the other on a dry basis).

For example, flow rate monitors always measure stack gas flow on a wet basis. This means that the volume of gas measured includes the contribution from the moisture content of the stack gas. Therefore, when a gaseous pollutant such as SO_2 is measured on a dry basis, in order to obtain the correct mass emission rate in lb/hr, the dry-basis SO_2 concentration is multiplied by the wet-basis stack gas flow rate, and a moisture correction is applied. As a second example, when NO_x emisssion rate in lb/mmBtu is measured, a moisture correction is needed if the NO_x concentration and diluent gas monitors measure on different moisture bases.

If a correction for the stack gas moisture content is required, one of the following moisture measurement methods must be used:

- An O_2 analyzer (or analyzers) capable of measuring on both a wet and dry basis.
- A continuous moisture sensor.
- A stack temperature sensor and a moisture look-up table (for saturated gas streams only).
- A fuel-specific default moisture value defined in Part 75 (for coal and wood, only).
- A site-specific default moisture value approved by petition under §75.66.

Table 7: Correction for Stack Gas Moisture Content

For this parameter . . .	A correction for stack gas moisture is required if . . .
SO_2 mass emission rate (lb/hr)	SO_2 concentrations are measured on a dry basis
NO_x emission rate (lb/mmBtu)	NO_x and diluent gas concentrations are not measured on the same moisture basis
NO_x mass emissions (lb)	NO_x mass is calculated as the product of NO_x concentration, stack gas flow rate and operating time, and the NO_x concentrations are measured on a dry basis
Hg mass emissions (ounces)	Hg concentrations are measured on a dry basis
CO_2 mass emission rate (tons/hr)	CO_2 concentrations are measured on a dry basis
Heat input rate (mmBtu/hr)	CO_2 is the diluent gas and is measured on a dry basis; or O_2 is measured as the diluent gas

3.7 What if a unit has multiple stacks or shares a stack with other units?

If a unit shares a common stack with other units or emits through multiple stacks, Part 75 requires procedures to be implemented that ensure complete emissions and heat input accounting. In some cases, the procedures will require monitoring systems to be installed at more than one stack or duct location. The configuration of ductwork and stacks, the program(s) that the unit is subject to, and the regulatory status of the units (i.e., affected or non-affected) determine the number of monitors needed and the required locations.

Common and multiple stack configurations for the various trading programs are addressed in several different places within Part 75. For Acid Rain Program units, the rule provisions pertaining to common and multiple stacks are found in §§ 75.16 through 75.18. For CAIR SO_2 Trading Program units, the provisions are in §75.16. For NO_x Budget Trading Program units and CAIR NO_x Trading Program units, the applicable provisions are in §75.72. For Hg Budget units under CAMR, the common and multiple stack provisions are found in §75.82.

These rule provisions are summarized in Table II-A of Appendix II of this guide. For configurations that are not covered in Table II-A, sources should contact EPA for additional guidance.

3.8 What are the missing data procedures for CEMS ?

For each unit operating hour in which quality-assured CEMS data are not obtained (i.e., are missing), Part 75 requires substitute data to be reported. The rather complex CEMS missing data procedures are discussed in detail in Section 9 of this guide.

4.0 APPENDIX D METHODOLOGY FOR GAS-FIRED AND OIL-FIRED UNITS

If an affected unit meets the definition of gas-fired or oil-fired, the alternative methodology in Appendix D of Part 75 may be used instead of CEMS, for certain parameters. Appendix D applies only to the measurement of the SO_2 mass emission rate and the unit heat input rate.

> The alternative methodology in Appendix D of Part 75 for gas-fired and oil-fired units pertains to the monitoring of the SO_2 mass emission rate and the unit heat input rate.

4.1 What is a gas-fired or oil-fired unit ?

Gas-fired and oil-fired units are defined[17] in Tables 8 and 9.

Table 8: Gas-Fired Units

According to §72.2, a combustion unit is a gas-fired unit if it . . .
• Combusts natural gas or other gaseous fuel(s) (including coal-derived fuel), such that gaseous fuel combustion accounts for at least: ‣ 90.0 percent of the unit's average annual heat input during the previous three calendar years, and ‣ 85.0 percent of the annual heat input in each of those calendar years, and • Combusts fuel oil for the remaining heat input (if any)

Table 9: Oil-Fired Units

According to §72.2, a combustion unit is an oil-fired unit if it . . .
• Combusts only fuel oil and gaseous fuel(s), and • Does not meet the definition of a gas-fired unit in §72.2

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[17] The definitions of gas-fired and oil-fired in §72.2 each consist of two parts. One part of the definition applies to all purposes under the Acid Rain Program except for Part 75, and the other applies exclusively to Part 75. In Tables 8 and 9, only the Part 75-specific pieces of the definitions are presented.

4.2 What is the Appendix D alternative monitoring method ?

The alternative monitoring methodology in Appendix D requires continuous monitoring of the fuel flow rate and periodic sampling of the fuel characteristics, such as sulfur content, gross calorific value (GCV), and density. The measured fuel flow rates are used together with the results of the fuel sampling and analysis to determine the SO_2 mass emission rate and/or the unit heat input rate, depending on the requirements of the applicable program(s). The Appendix D methodology is summarized in Table 10.

Table 10: Appendix D Monitoring Methodology for Gas-Fired and Oil-Fired Units

If an affected unit is . . .	Part 75 allows . . .	And to obtain the necessary data . . .
In the Acid Rain Program or the CAIR SO_2 Trading Program and meets the definition of oil-fired or gas-fired in §72.2	The SO_2 mass emission rate (lb/hr) and the unit heat input rate (mmBtu/hr) to be calculated based on measured fuel flow rates and fuel characteristics	The fuel flow rate is continuously monitored, and Periodic fuel sampling and analysis is conducted to determine some or all of the following--- fuel sulfur content, GCV, and density
In the NO_x Budget Trading Program or the CAIR NO_x Trading Program(s), but is not in the Acid Rain Program or the CAIR SO_2 Trading Program, and if the unit meets the definition of oil-fired or gas-fired in §72.2	The unit heat input rate (mmBtu/hr) to be calculated based on measured fuel flow rates and fuel characteristics	The fuel flow rate is continuously monitored, and Periodic fuel sampling and analysis is conducted to determine the GCV

4.3 How is the fuel flow rate measured ?

Appendix D requires the fuel flow rate to be continuously monitored and the data to be reduced to hourly averages. To achieve this a certified fuel flowmeter or a commercial billing meter may be used. To certify a fuel flowmeter, its accuracy must be established using one of the methods[18] specified in section 2.1.5.1 of Appendix D.

[18] These methods represent consensus standards established by various organizations, e.g., ASME, API, AGA, and ISO.

- In most cases, the certification test procedure consists of calibrating the meter with a flowing fluid, at three flow rates covering its normal operating range**.** Generally, this requirement is met by calibrating the flowmeter in a laboratory, although the flowmeter may be calibrated at the affected facility, by comparison against an in-line "master meter" which has been tested for accuracy within the past 365 days using one of the methods in section 2.1.5.1 of Appendix D.

- Alternatively, an orifice-, nozzle- or venturi-type flowmeter may be certified if its primary element (for example, the orifice plate) meets the design criteria specified in American Gas Association Report No. 3, and if its pressure, temperature, and differential pressure transmitters are calibrated with standards traceable to the National Institute of Standards and Technology (NIST).

- A commercial billing meter may be used for Appendix D applications without certification, if the meter can provide hourly average fuel flow rates, and if the regulated source is not affiliated with the billing company.

4.4 What are the fuel sampling requirements of Appendix D ?

For both gaseous fuels and fuel oil, Appendix D requires periodic sampling of fuel characteristics (sulfur content and/or GCV and/or density). The required samples may be taken either by the owner/operator, the fuel supplier, or by an independent laboratory.

Sampling of gaseous fuels

Appendix D divides gaseous fuels into three categories: (1) pipeline natural gas (PNG); (2) natural gas; and (3) other gaseous fuels. The distinction between PNG and natural gas is in the fuel sulfur content. Natural gas may have as much as 20 grains of total sulfur per 100 standard cubic feet (i.e., 20 gr/100 scf), but to qualify as PNG, the total sulfur content of the gas must not exceed 0.5 gr/100 scf. The Appendix D fuel sampling and analysis requirements for gaseous fuels are as follows:

- For PNG and natural gas, <u>annual</u> sampling of the total sulfur content[19] is required, unless a valid fuel contract is in place documenting that the fuel meets the definition of PNG or natural gas. If such a contract exists, the owner or operator may choose not to perform the annual sampling—however, the maximum total sulfur content specified in the contract (often 20 gr/100 scf) must then be used to calculate the SO_2 emissions.

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[19] Acid Rain Program and CAIR SO_2 Program units, only

- The GCV of PNG or natural gas must be determined monthly, with certain exceptions for units that operate infrequently.

- For other gaseous fuels transmitted by pipeline, the required frequency of total sulfur sampling[19] is hourly, unless the results of a 720-hour demonstration[20] show that the fuel qualifies for less frequent (i.e., daily or annual) sampling.

- The GCV of other gaseous fuels transmitted by pipeline must be determined daily, or hourly unless the fuel is demonstrated [20] to have a low GCV variability, in which case monthly sampling is sufficient.

- For other gaseous fuels delivered in shipments or lots, each shipment or lot must be sampled for sulfur content[19] and GCV.

Acceptable ASTM and GPA sampling and analysis methods for gaseous fuels are referenced in sections 2.3.3.1.2 (for fuel sulfur content) and 2.3.4 (for fuel GCV) of Appendix D.

Fuel oil sampling

For oil, Appendix D provides several fuel sampling and analysis options. The required sampling of the sulfur content[19], GCV and, if applicable, density of the oil may be done using any of the following methods:

- Daily sampling; or

- Composite sampling for up to 168 hours, using hourly flow-proportional sampling or continuous drip sampling; or

- Sampling after each addition of oil to the storage tank; or

- Sampling each delivery or "lot" of fuel (i.e., each ship load, barge load, group of trucks, etc). The sample may be taken from either the supplier's storage tank or from the shipment tank (container) upon receipt.

Acceptable ASTM sampling and analysis methods for fuel oil are given in sections 2.2.5 (for fuel sulfur content) and 2.2.7 (for fuel GCV) of Appendix D.

[20] See sections 2.3.5 and 2.3.6 of Appendix D

4.5 How is the SO_2 mass emission rate calculated ?

For an Acid Rain Program unit using the Appendix D methodology, the hourly SO_2 mass emission rate is calculated using an equation that has one of the following basic structures:

SO_2 mass emission rate (lb/hr) = Fuel flow rate x Fuel sulfur content x Units conversion factor

or

SO_2 mass emission rate (lb/hr) = SO_2 emission rate (lb/mmBtu) x Heat input rate (mmBtu/hr)

An example of an equation with the first basic structure is Equation D-2 in section 3 of Appendix D, and an equation with the second basic structure is Equation D-5. In the first general equation above, the fuel flow rate is the hourly average reading from the fuel flowmeter, and the fuel sulfur content is based on the results of periodic fuel sampling and analysis (see Section 4.7, below). In the second general equation, the heat input rate is derived from the hourly average fuel flowmeter reading and the fuel GCV (see Section 4.6, below), and the SO_2 emission rate is either:

- A generic default value for the type of fuel combusted (e.g., 0.0006 lb/mmBtu for PNG); or
- A site-specific default value, determined by substituting the GCV and total sulfur content of the fuel into Equation D-1h in Appendix D.

Note that for oil, when the fuel flow rate is measured on a volumetric basis (e.g., gal/hr), it must be converted to a mass basis using the oil density. Therefore, for Acid Rain sources using volumetric oil flowmeters, periodic sampling of the density of the oil is also required.

4.6 How is the unit heat input rate calculated ?

For an Acid Rain, NO_x Budget, or CAIR unit using Appendix D to determine the hourly unit heat input rate, an equation with the following basic structure is used:

Heat input rate (mmBtu/hr) = Fuel flow rate x Fuel GCV x Units conversion factor

Examples of equations having this basic structure are Equations D-6 and D-8 in section 3 of Appendix D. In the general equation above, the fuel flow rate is the hourly average reading from the fuel flowmeter, and the GCV is based on the results of periodic fuel sampling and analysis. The units of measure for the fuel flow rate and the GCV must be consistent. For example, if the fuel flowmeter measures in gallons per hour, the GCV is expressed in units of Btu per gallon.

4.7 Which sulfur content, GCV, and density values are used in the calculations ?

Appendix D provides the source owner or operator with considerable flexibility in selecting the values of fuel sulfur content, GCV and density that are used in the emission and heat input calculations. Generally speaking, the values used in the calculations are determined in one of two ways:

(1) ***The results of the fuel sampling and analysis are used directly in the calculations*.**

Example 1: The GCV from the most recent monthly sample of pipeline natural gas is used in the heat input rate calculations.

Example 2: For a process gas, hourly samples are taken of the sulfur content and GCV, and the hourly values are used to calculate the SO_2 emissions and unit heat input rate;

or

(2) ***An "assumed value" is used in the calculations. The assumed value may be:***

- A default SO_2 emission rate of 0.0006 lb/mmBtu, for a fuel that qualifies as pipeline natural gas; or

- The highest value from any required sample taken in the previous calendar year; or

- The highest value from any sample taken in a specified "look-back" period; or

- The highest value specified in a valid, active fuel contract or tariff sheet; or

- The value obtained from a 720-hour characterization of the fuel's sulfur content or GCV[21]

This calculation method is subject to the following conditions:

- If the results of any required fuel sampling and analysis exceed the assumed value, then that sample result becomes the new assumed value; and
- If the assumed value is from a fuel contract or tariff sheet, and if the contract or tariff sheet is superseded by a new one, then the assumed value may have to be adjusted, or, in some instances, the fuel may have to be re-classified. Consider the following examples:

Example 1: A maximum GCV of 105,000 Btu/100 scf is specified in a valid, active natural gas contract. This GCV value may continue to be used in the heat input rate calculations, provided that it is not exceeded, either by the results of a required monthly GCV sample, or by the maximum GCV value in a new contract.

Example 2: In 2004, the highest percent sulfur (%S) value obtained from the required samples of distillate oil was 0.15 %S, by weight. This %S value may be used in the SO_2 emission calculations throughout 2005, provided that it is not exceeded by the results of any required fuel sample.

Example 3: Daily manual sampling of fuel oil is performed, and on each successive unit operating day, the highest sulfur content, GCV, and density values from the previous 30 daily samples are used in the calculations.

Example 4: The results of a 720-hour demonstration under section 2.3.6 of Appendix D show that a process gas has a low sulfur variability. A default SO_2 emission rate of 0.025 lb/mmBtu is calculated by substituting the 90^{th} percentile value of the fuel's sulfur content from the demonstration into Equation D-1h. This default emission rate may continue to be used unless it is exceeded when Equation D-1h is applied to the results of a required annual sample of the fuel's sulfur content.

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[21] For gaseous fuels other than natural gas, which are transmitted by pipeline—see sections 2.3.5 and 2.3.6 of Appendix D

Example 5: A fuel initially qualifies as pipeline natural gas, based on historical fuel sampling data. In this year's required annual fuel sampling and analysis, 3 samples are taken and the total sulfur content of all samples is between 1.0 and 1.5 gr/ 100 scf. The fuel is therefore re-classified as "natural gas" and the average total sulfur value from the 3 samples is used in Equation D-1h, to calculate a site-specific default SO_2 emission rate

For a complete listing of all of the available calculation options for fuel oil and gaseous fuels, see Tables D-4 and D-5 in Appendix D. Also note that for each of these options, instructions are given in section 2.3.7 of Appendix D, explaining when and how to apply the fuel sampling results. This helps to ensure national consistency in the reporting of Appendix D data.

4.8 What are the on-going quality-assurance requirements of Appendix D ?

Following initial certification, each Appendix D fuel flowmeter (except for qualifying fuel billing meters) must undergo periodic accuracy testing, using the same general approach that was used for initial certification (see Section 4.3, above). Fuel flowmeter accuracy testing must be performed once every 4 calendar quarters, unless the flowmeter qualifies for an extension of the test deadline. A one-quarter extension of the test deadline may be claimed for any calendar quarter in which:

- The fuel measured by the flowmeter is burned for less than 168 hours[22] . This type of extension is most advantageous for fuels that are seldom combusted and for units that operate infrequently; or

- The optional fuel flow-to-load ratio test described in section 2.1.7 of Appendix D is performed and passed. This option is most useful for fuels that are routinely combusted for more than 168 hours per quarter.

Note that fuel flowmeter accuracy test deadlines may not be extended indefinitely. The limits to these extensions are as follows:

- If the deadline extension is based on infrequent combustion of a fuel or infrequent unit operation, a flowmeter accuracy test must be performed no later than 4 "QA" quarters[22] or 20 calendar quarters—whichever comes first—after the quarter in which the previous test was done; or

[22] The term "fuel flowmeter QA operating quarter" (see §72.2) is used to describe a quarter in which the fuel measured by the flowmeter is combusted for 168 hours or more. All such "QA quarters" count toward the accuracy test deadline. Test deadline extensions may only be claimed for "non-QA" quarters.

- If the deadline is being extended by performing the fuel flow-to-load ratio test, the maximum allowable extension is 20 calendar quarters from the quarter of the previous test.

In addition to performing periodic fuel flowmeter accuracy testing, section 1.3 in Appendix B of Part 75 requires the owner or operator of an Appendix D unit to develop and implement a quality-assurance plan. The essential elements of the QA plan include the following:

- A written record of the fuel flowmeter accuracy test procedures;
- Records of maintenance, adjustments, and repairs of the fuel flowmeter(s); and
- A written record of the standard procedures used to perform the required fuel sampling and analysis.

4.9 What are the missing data procedures for an Appendix D unit ?

Whenever fuel flow rate data or any of the required fuel sampling data is missing, Appendix D requires substitute data values to be reported. The Appendix D missing data procedures are discussed in detail in Section 9 of this guide.

5.0 APPENDIX E METHODOLOGY FOR GAS-FIRED AND OIL-FIRED PEAKING UNITS

If a unit is in the Acid Rain Program, NO_x Budget Program, or CAIR NO_x Trading Program(s), and it meets the definition of a "peaking unit" in §72.2, and if it also qualifies as oil-fired or gas-fired (see Section 4.1, above), then the alternative methodology in Appendix E of Part 75 may be used to monitor the NO_x emission rate, in lieu of installing CEMS. For a qualifying Appendix E unit:

- The Appendix D methodology must be used to measure the hourly unit heat input rate (see Section 4.6, above); and

- Emission testing must be conducted at four different loads to develop a correlation curve of NO_x emission rate versus heat input rate

> The Appendix E methodology for gas-fired and oil-fired peaking units pertains only to the monitoring of NO_x emission rate. To use this methodology, a correlation curve of NO_x emission rate vs heat input rate is first derived from emission testing, Then, the hourly unit heat input rate is measured using the Appendix D methodology, and the hourly NO_x emission rate is determined from the correlation curve.

5.1 What is a peaking unit ?

The definition of a peaking unit is presented in Table 11. Table 11 shows that for a unit that reports emissions data year-round, peaking unit qualification depends on the annual capacity factor[23] of the unit. For units in the NO_x Budget Program and units in the CAIR Ozone Season Trading Program that report emissions only for the ozone season months (May through September), peaking unit qualification depends on the ozone season capacity factor[24] of the unit.

Table 11. Peaking Units

According to §72.2, a combustion unit is a peaking unit if it has...
• An average annual capacity factor of 10.0 percent or less over the past three years;
and
• An annual capacity factor of 20.0 percent or less in each of those three years

[23] According to §72.2, the annual capacity factor is either: (1) the ratio of the unit's actual annual electrical output to the nameplate capacity times 8,760; or (2) the ratio of the unit's actual annual heat input to the maximum design heat input times 8,760

[24] The ozone season capacity factor is calculated in the same basic way as the annual capacity factor, except that the ozone season heat input or electrical output is used in the calculation, and "8,760" is replaced with "3,672", which is the number of hours in the ozone season (see §75.74(c)(11)).

5.2 How is an Appendix E correlation curve constructed ?

Appendix E correlation curves are derived from emission test results. Appendix E requires an initial four-load NO_x emission rate test to be performed for each type of fuel combusted in the unit, except for emergency fuel, for which the testing is optional. For boilers, the testing is performed using EPA Reference Methods 7E and 3A, and for combustion turbines and diesel or dual-fuel reciprocating engines, Reference Method 20 is used[25]. The emission testing is done at four evenly-spaced load points, ranging from the minimum to the maximum unit operating load, and three test runs are performed at each load level. For existing units, two years of historical data are used to establish the minimum and maximum operating loads. For new units, five-year projections of the minimum and maximum loads are used.

During each Appendix E test run, the unit heat input rate is determined using the fuel GCV and readings from a fuel flowmeter that meets the requirements of Part 75, Appendix D. Also, certain parameters must be monitored during each test run. For boilers, excess oxygen is monitored, and it must either be set at a normal level or at a conservatively high level. For turbines and diesel or dual-fuel reciprocating engines, at least four parameters indicative of the unit's NO_x formation characteristics are monitored and acceptable ranges for each parameter are established during testing. If a turbine uses water injection to control NO_x emissions, the water-to-fuel ratio must be one of the monitored parameters.

The NO_x emission rate and heat input rate data are averaged at each load level. Then, a correlation curve of NO_x emission rate (lb/mmBtu) versus heat input rate (mmBtu/hr) is

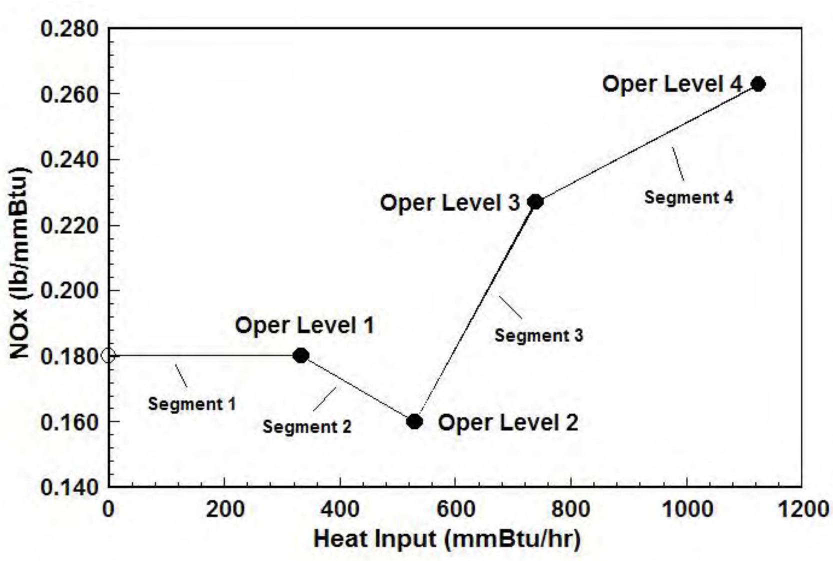

Figure 2: Typical Appendix E Correlation Curve

[25] These test methods are found in Appendices A-2, A-4 and A-7 of 40 CFR Part 60.

constructed and the curve segments are programmed into the data acquisition and handling system (DAHS). A typical Appendix E correlation curve is shown in Figure 2, above.

5.3 How are the hourly NO_x emissions determined?

The Appendix E methodology is summarized in Table 12. The hourly NO_x emission rate

Table 12: Appendix E Methodology for Determining NO_x Emissions from Oil-and Gas-Fired Peaking Units

To use Appendix E to determine . . .	The following data must be collected . . .	And the following calculations must be performed . . .
NO_x emission rate (lb/mmBtu)	The fuel flow rate must be continuously monitored, using an Appendix D fuel flowmeter; and Periodic fuel sampling, according to Appendix D, is required to determine the GCV.	Use the measured fuel flow rates and GCV to determine the hourly unit heat input rate; and Select from the correlation curve the NO_x emission rate that corresponds to the measured hourly heat input rate.
NO_x mass emissions (lb)	The fuel flow rate must be continuously monitored, using an Appendix D fuel flowmeter; and Periodic fuel sampling, according to Appendix D, is required to determine the GCV; and The unit operating time must be monitored.	Use the measured fuel flow rates and GCV to determine the hourly unit heat input rate; and Select from the correlation curve the NO_x emission rate that corresponds to the measured hourly heat input rate; and Multiply together the measured hourly heat input rate, the NO_x emission rate from the correlation curve, and the unit operating time.

is determined by measuring the hourly heat input rate[26] and reading the corresponding NO_x value from the Appendix E correlation curve[27]. To calculate the hourly NO_x mass emissions, the unit operating time[28] must also be known.

If different fuels are co-fired in an Appendix E unit, there are two possible ways of determining the hourly NO_x emission rate:

- Calculate the heat input rate for each type of fuel combusted during the hour, using the fuel flow rate and the GCV. Then, determine a NO_x emission rate for each fuel from its correlation curve and use Equation E-2 in Appendix E to calculate a Btu-weighted hourly NO_x emission rate for the unit; or

- If a consistent fuel mixture is <u>always</u> combusted in the unit (i.e., if the composition of the mixture does not vary by more than ±10%), a single correlation curve for the mixture may be derived, rather than developing separate curves for the individual fuels. If a unit qualifies to use this option, the hourly heat input rate will be a composite value[29], derived from the individual fuel flow rates, the GCV values, the fuel usage times[30], and the unit operating time[28].

5.4 What are the fuel sampling requirements of Appendix E ?

Appendix E requires the owner or operator of an affected unit to use the fuel sampling and analysis procedures of Appendix D, to determine the GCV of each type of fuel combusted in the unit. Therefore, the GCV sampling options and analytical methods described in section 4.4 of this guide, apply to Appendix E units.

5.5 What are the on-going quality-assurance requirements of Appendix E ?

The on-going quality-assurance requirements for Appendix E units are as follows:

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[26] See Section 4.6 of this guide.

[27] The NO_x emission rate value is, of course, read automatically by the DAHS

[28] The unit operating time is defined as the fraction of the hour in which the unit operates. For example, unit operating time = 1.00 for a full hour of operation, 0.50 for a half-hour of operation, etc.

[29] The equations needed to determine the heat input rates for each fuel, the total unit heat input, and the unit level heat input rate are: Equations F-19 and F-20 in Appendix F of Part 75, Equation E-1 in Appendix E, and Equation F-21c in Appendix F.

[30] Fuel usage time is the fraction of an hour that a fuel is combusted (e.g., fuel usage time = 1.00 if the fuel is burned for the whole hour, 0.50 if it is burned for 30 minutes, etc.)

- ***Parameter Monitoring.*** Once the initial correlation curve has been developed, Appendix E requires hourly monitoring of the parameters that were monitored during the baseline emission testing (i.e., excess O_2 for boilers and the four parameters associated with NO_x formation for turbines and diesel or dual-fuel reciprocating engines).

  If, for any boiler operating hour, the excess O_2 data is missing or invalid, or if the excess O_2 level is greater than 2% O_2 higher than the value observed during the baseline emission testing at the same heat input rate, then substitute NO_x emission rate data must be reported for that hour. Similarly, for turbines, diesel and dual fuel reciprocating engines, for any hour in which some or all of the required parametric data is missing, invalid or outside the acceptable ranges established during the baseline emission testing, missing data substitution must be used for NO_x emission rate.

- ***Periodic Re-testing.*** Appendix E requires periodic re-testing of each affected unit once every 5 years (20 calendar quarters), to determine new correlation curves. Unscheduled re-testing is also required if:

  - For boilers, the excess O_2 level at a particular heat input rate is more than 2% O_2 greater than the value observed during the baseline emission testing, for more than 16 consecutive unit operating hours; or

  - For combustion turbines and for diesel or dual-fuel reciprocating engines, some or all of the required parametric data is outside the acceptable ranges established during the baseline emission testing for more than 16 consecutive unit operating hours.

- ***QA Plan.*** The owner or operator of an Appendix E unit is required to develop and implement a quality-assurance (QA) plan for the unit. The contents of the plan are specified in section 1.3.6 of Part 75, Appendix B and section 4 of Appendix E. At a minimum, the QA plan must include:

  - The data and results from the initial and most recent NO_x emission rate testing, including the parametric data;

  - A written record of the procedures used to perform the NO_x emission rate testing;

  - The quality-assurance parameters that are monitored and the acceptable values and ranges of those parameters;

- Records of the monitored parametric data for each unit operating hour; and

- Because Appendix E requires an Appendix D fuel flowmeter to be used to monitor the hourly unit heat input rate, the flowmeter must meet the on-going QA requirements of Appendix D. Therefore, the the QA plan must also include the elements described in Section 4.8 of this guide.

5.6 What are the missing data procedures for an Appendix E unit ?

The owner or operator of an Appendix E unit is required to implement the missing data procedures of both Appendix D (for fuel flow rate and GCV) and Appendix E (for NO_x emission rate). These procedures are discussed in detail in Section 9 of this guide.

5.7 What happens if an Appendix E unit loses its peaking unit status ?

If, at the end of any calendar year or ozone season, the capacity factor requirements in Table 11, above, have not been met for an Appendix E unit, its peaking unit status is lost at that point. When this happens, Part 75 requires a NO_x-diluent monitoring system to be installed and certified by December 31 of the calendar year following the year in which the peaking status is lost. For example, if, at the end of 2004, the 3-year average annual capacity factor of an Appendix E unit for 2002, 2003 and 2004 is determined to be 12.5%, then a NO_x-diluent CEMS must be installed and certified by December 31, 2005 [31].

A unit which has previously qualified as a peaking unit but loses that status may qualify again as a peaking unit in a subsequent year or ozone season, but only if capacity factor data for a three year period following the loss of peaking status show that the unit once again meets the criteria in Table 11, above.

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[31] The Appendix E methodology should continue to be used until the CEMS has been certified or until the December 31st deadline, whichever occurs first. If the certification deadline is not met, the maximum potential NO_x emission rate must be reported for each unit operating hour until the CEMS is certified.

6.0 LOW MASS EMISSIONS METHODOLOGIES

6.1 Gas-Fired and Oil-Fired Units

> The low mass emissions (LME) methodology in §75.19 provides an alternative to CEMS for determining SO_2, NO_x, and CO_2 emissions and unit heat input. To qualify to use the LME methodology, a unit must be gas-fired or oil-fired, and its SO_2 and/or NO_x mass emissions must not exceed certain annual and/or ozone season limits.

Part 75 provides an alternative monitoring methodology (§75.19) that may be used instead of CEMS, for gas- and oil-fired units that have very low mass emissions. This low mass emissions, or "LME" methodology does not require actual continuous monitoring of emissions or unit heat input. Rather, hourly SO_2 , NO_x and CO_2 emissions are estimated using fuel-specific default emission rates ("emission factors"), and hourly heat input is either estimated from records of fuel usage, or it is reported as the maximum rated heat input for each unit operating hour. Once the LME methodology has been selected, it must be used for all program parameters. "Mixing-and-matching" LME with other Part 75 methodologies is not allowed. Therefore, the LME methodology must be used for SO_2 , NO_x , CO_2 and heat input if the unit is in the Acid Rain Program, for SO_2 and heat input if the unit is in the CAIR SO_2 Trading Program, and for NO_x and heat input if the unit is in the NO_x Budget Program or if it is in the CAIR NO_x Trading Program(s).

6.1.1 What is a low mass emissions (LME) unit ?

Low mass emission units are defined in Table 13.

Table 13. Low Mass Emissions Units

A combustion unit may qualify as a low mass emissions, or "LME" unit if it meets the definition of a gas-fired or oil-fired unit in §72.2, and if its SO_2 and/or NO_x mass emissions meet the following limits:	
For Acid Rain and CAIR SO_2 Trading Program units:	*For NO_x Budget Program and CAIR NO_x Trading Program units:*
• $\leq$25 tons of SO_2 per year and • < 100 tons of NO_x per year	• $\leq$50 tons of NO_x per ozone season and • < 100 tons of NO_x per year[a]

[a] This limit applies only if the source is required to (or elects to) report NO_x mass emissions on a year-round basis.

6.1.2 How does a unit qualify for LME status ?

To use the LME methodology for a particular gas-fired or oil-fired unit, a certification application must be submitted to EPA and to the appropriate State or local agency, at least 45 days prior to the date on which the methodology will first be used. The essential elements of the certification application, which has both electronic and hard copy portions[32], are as follows:

- The application must include a complete monitoring plan for the unit[33]; and

- For sources that report emissions data on a year-round basis, the application must demonstrate that in each of the three calendar years immediately preceding the year of the application, the SO_2 and/or NO_x mass emissions from the unit did not exceed the annual threshold limits shown in Table 13 above. And if the unit is in the NO_x Budget Program or in the CAIR Ozone Season Trading Program, it must be demonstrated that in each of the previous three ozone seasons, the NO_x mass emissions did not exceed 50 tons.

  To make the required demonstration(s):

  - Emissions data from historical Part 75 electronic data reports (EDRs) <u>must</u> be used, where these reports are available, except as noted immediately below; or

  - In the absence of historical EDRs, reliable estimates of the unit's emissions for the previous 3 years (or ozone seasons) must be provided. These estimates may be based on records of unit operation, fuel usage, representative emission test data, CEM data, fuel sampling data, etc. Conservative default values may also be used in the calculations (e.g., the "generic" emission rates from Tables LM-1 through LM-3 in §75.19, the unit's maximum rated heat input, etc.)[34]; or

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[32] The electronic portion is sent to the EPA Clean Air Markets Division. The hard copy portion goes to the State and to the EPA Regional Office.

[33] For assistance in preparing the electronic portion of the monitoring plan, see Table A-14 in Appendix A of the EDR Instructions. A tutorial on CD-ROM is also available at the following web address: www.epa.gov/airmarkets/monitoring/mdc/index.html

[34] If emission testing will be performed to determine a default NO_x emission rate, but at the time of the application, the testing has not yet been completed, and if the generic default NO_x emission rate from Table LM-2 is inappropriately high for the unit, then, for the purposes of initial LME qualification, a more reasonable (but still conservatively high) default emission rate may be used in the calculations. For example, if the unit is not equipped with SCR or SNCR, a default NO_x emission rate based on the permit limit may be used, or, for units with SCR or SNCR, a default NO_x emission rate of 0.15 lb/mmBtu may be used. However, note that these emission estimates may not be used for Part 75 reporting purposes. Rather, the generic NO_x emission rates from Table LM-2 in §75.19 or the maximum potential emission rate (MER) must be reported until NO_x emission testing has been completed.

- For units with less than 3 years (or ozone seasons) of operating history, projected emissions estimates for one or more years may be used, to make up the difference. Projections may also be used if emission controls have been recently installed and the emissions data for one or more of the past 3 years or ozone seasons is not representative of present emission levels. All projections should be based on the anticipated manner of unit operation, the type(s) of fuel(s) that will be burned, and the expected emission rates; or

- If a unit cannot qualify for LME status based on its historical emissions and is not eligible to use projected emissions estimates, it is still possible to use the LME methodology if an enforceable permit restriction is accepted, limiting the number of unit operating hours per year (or ozone season), so that the LME emission thresholds will not be exceeded; and

- The certification application must also specify the projected date on which the LME methodology will first be used. Note that this projected date may not be arbitrarily selected, because §75.19 requires the LME methodology to be used for all unit operating hours in a calendar year or ozone season. Therefore, the only acceptable start dates for using the LME methodology are these:

  - For an existing unit that reports emissions data on a year-round basis, the first unit operating hour in a calendar year.

  - For an existing unit that reports on an ozone season-only basis, the first unit operating hour in an ozone season.

  - For new Acid Rain Program units, and for new units in the CAIR SO_2 and NO_x Trading Programs, at the hour of commencement of commercial operation (as defined in §72.2).

  - For new units in the NO_x Budget Program, at the first hour of unit operation ("first-fire"); and

- Finally, the certification application must describe the calculation methodology that will be used to ensure that the unit maintains its LME status. That is:

  - For each emissions parameter (i.e., SO_2 , CO_2 , and/or NO_x), the application must indicate whether the generic default emission rates in Tables LM-1 through LM-3 will be used in the calculations, or whether site-specific default values, determined by emission testing or other acceptable means, will be used; and

- For heat input, the application must indicate whether the maximum rated unit heat input will be reported for every operating hour or whether the long-term fuel flow methodology, based on records of fuel usage, will be used.

These calculation methods are discussed in greater detail in Section 6.3, below.

Once a complete certification application has been received by EPA and the State, the LME methodology is assigned a provisionally certified status, pending the results of Agency review. The regulatory agencies have a period of 120 days from the receipt of a complete application to review the application and to issue a notice of approval or disapproval to the source. If no such notice is provided by day 120, then the methodology is considered to be "certified by default". However, note that the LME methodology may not be used prior to the start date indicated in the certification application, even if a notice of approval is issued or if the methodology is certified by default prior to that date.

6.1.3 How are emissions and heat input calculated for an LME unit ?

To calculate the hourly SO_2 , NO_x and CO_2 mass emissions in lb (or tons)[35], default emission rates, expressed in units of lb/mmBtu (or ton/mmBtu)[35], are used together with an estimate of the unit heat input (mmBtu).

Generic vs. Site-Specific Default Emission Rates

For the combustion of fuel oil and natural gas, the generic default emission rates in Tables LM-1 and LM-3 must be used to estimate SO_2 and CO_2 emissions, unless a petition to use alternative emission rates has been approved under §75.66. However, for NO_x, use of the generic default emission rates in Table LM-2 is optional. In lieu of using these generic values, emission testing may be performed to determine site-specific NO_x emission rates.

If the unit combusts a gaseous fuel other than natural gas, site-specific default emission rates must be determined in the following way for all program parameters, since there are no generic values in §75.19 for such fuels:

- For SO_2, the sulfur content of the fuel is quantified by performing the 720-hour demonstration described in Part 75, Appendix D, section 2.3.6, to determine whether the unit is eligible to use a default SO_2 emission rate for reporting purposes. If the unit is not eligible, then the LME methodology may not be used. But if the unit is eligible, the appropriate value of the fuel's total sulfur content (from the demonstration) is substituted into Equation D-1h in Appendix D, to determine the default SO_2 emission rate in units of lb/mmBtu.

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[35] The emission rates are in lb/mmBtu for SO_2 and NO_x , and in ton/mmBtu for CO_2.

- For NO_x, fuel-and unit-specific emission testing is performed to determine the default emission rate(s), in units of lb/mmBtu.

- For CO_2, fuel sampling and analysis is performed to determine a carbon-based F-factor for the gas. Then, Equation G-4 in Appendix G of Part 75 is solved for the ratio of (W_{CO2}/H), to obtain the CO_2 emission factor in units of tons/mmBtu.

Heat Input Methodologies

To determine the hourly heat input for an LME unit, there are two options:

- The maximum rated unit heat input may be reported for each unit operating hour; or

- Long-term fuel flow may be used. The long-term fuel flow methodology requires a reliable estimate of the amount of each type of fuel combusted in the unit during each quarter[36]. Data from certified Appendix D fuel flowmeters or gas billing records may be used to make these estimates. Alternatively, for fuel oil, one of several acceptable API "tank drop" measurement methods may be used. The total unit heat input for the quarter is calculated from the estimated quarterly fuel usage and the fuel GCV[37]. The total heat input is then apportioned to the individual unit operating hours, on the basis of unit load.

Basic Equations

To determine the hourly SO_2 , NO_x, and CO_2 mass emissions, an equation that has the following basic structure is used:

Mass emissions = Default emission rate x Hourly heat input
(lb or tons) (lb or tons/mmBtu) (mmBtu)

In the general equation above, the term "hourly heat input" either represents the product of the maximum rated hourly unit heat input (mmBtu/hr) and the unit operating time[38] (hr), or is an

[36] For ozone season-only reporters, the 2nd quarter includes only the months of May and June.

[37] For oil and natural gas, either use Appendix D fuel sampling procedures to determine the GCV or use default GCV values from Table LM-5. For other gaseous fuels, the GCV must be measured at the frequency prescribed by Appendix D.

[38] Unit operating time is the fraction of the hour that the unit combusts fuel, i.e., 1.00 if the unit opeartes for the whole hour, 0.50 if it operates only for half of the hour, etc. When using the LME methodology, an operating time of 1.00 may be used for partial unit operating hours.

apportioned value from the long-term fuel flow methodology.

The heat input apportionment equations for long-term fuel flow have the general form:

$$\underset{(mmBtu)}{\textit{Hourly heat input}} = \underset{(mmBtu)}{\textit{Total quarterly heat input}} \times \frac{\textit{Hourly unit load}}{\textit{Sum of all quarterly loads}}$$

In this general equation, the unit loads are expressed on a consistent basis, either in megawatts or thousands of pounds (klb) of steam per hour.

The quarterly SO_2 , NO_x, and CO_2 mass emissions are calculated by summing the hourly mass emissions and converting this sum to tons as necessary (i.e., for SO_2 and NO_x). The cumulative annual (or ozone season) tons of SO_2 , NO_x, and CO_2 are calculated by summing the appropriate quarterly values. The cumulative SO_2 and/or NO_x values are then compared against the LME emission threshold values in Table 13, above, to determine whether the unit has retained its LME status.

6.1.4 How are site-specific default NO_x emission rates determined for an LME unit ?

There are three basic sources of information that may be used to determine the site-specific NO_x emission rate(s) for a LME unit. These are:

- Emission testing;
- Historical CEMS data; and
- Previous Appendix E test results

Emission Testing

As explained in Section 6.1.3 above, emission testing <u>may</u> (and for gaseous fuels other than natural gas, <u>must</u>) be performed to establish fuel- and unit-specific default NO_x emission rates for a LME unit. Testing at four load levels is required (with some exceptions---see below), with three runs at each load. The basic procedures described in Part 75, Appendix E, section 2.1 are used for the testing, except that unit heat input is not measured during the test runs. Periodic re-testing is required, once every five years (20 calendar quarters).

EPA Reference Methods 7E and 3A are used to test boilers and Method 20 is used for combustion turbines[39], except that the NO_x concentrations are not corrected to 15% O_2. In addition, for units equipped with add-on NO_x emission controls (e.g., water injection, SCR, etc.) and for combustion turbines that use lean premix (dry low-NO_x) technology to reduce NO_x emissions, appropriate parameters must be monitored and recorded during the test period, to document that the emission controls are working properly. From this data, acceptable values

[39] These reference methods are found in Appendices A-2, A-4 and A-7 of 40 CFR Part 60.

and/or ranges for each parameter are established and kept in a quality-assurance plan for the unit.

For a group of "identical" LME units, a subset of the units may be tested, rather than testing each unit individually. To be considered identical, all of the units in the group must:

- Be of the same size (maximum rated hourly heat input); and
- Have the same history of modifications (e.g., control device installations, frequency of major maintenance outages, etc.); and
- Have stack or turbine outlet temperatures within ±50°F of the average stack or turbine outlet temperature for the group.

If the group of LME units qualifies as identical, Table LM-4 in §75.19 is used to determine how many units need to be tested (e.g., if there are 3 to 6 units in the group, at least 2 units must be tested).

In the following instances, the initial NO_x emission rate testing (or periodic retesting) for LME units may be done at fewer than four loads

- Testing may be done at a single load if the unit has operated at a single load level for at least 85% of the operating hours in the past 3 years or ozone seasons; or

- Testing may be conducted at two or three load levels if those load levels cumulatively represent at least 85% of the operating hours in the past 3 years or ozone seasons; or

- For combustion turbines that operate principally at base-load (or at a set-point temperature), but are capable of operating at a higher peak load level (or at a higher internal operating temperature), testing may be done only at base-load, provided that a suitable upward adjustment is made to the base-load NO_x emission rate when the unit operates at peak load[40]; or

- If the initial testing was performed at multiple load levels, the required retests may be done at single load, i.e., at the load level for which the highest NO_x emission rate was obtained in the initial test.

Historical CEMS Data

If a unit has at least three years (or ozone seasons) of quality-assured historical NO_x emission rate data from a NO_x-diluent CEMS, the CEMS data may be used to determine fuel- and unit-specific default NO_x emission rates. In order to do this, at least 168 hours of quality-assured data are required for each fuel type, representing the full range of normal unit operating

40 This adjustment is described below, in section 6.1.5.

conditions.

Appendix E Test Results

For a peaking unit switching from the Appendix E methodology (see Section 5 of this guide) to LME, the results of a previous four-load Appendix E NO_x emission test may be used to determine the site-specific default NO_x emission rates, provided that the test results are less than 5 years old.

6.1.5 Which site-specific default NO_x emission rates are used for reporting ?

Once the necessary emission test data or CEMS data for each type of fuel combusted in the unit have been obtained, as described in Section 6.1.4, above, the site-specific default NO_x emission rate(s) that will be used for Part 75 reporting are determined as follows:

- **If the NO_x emission rate is based on emission test results:**

  - Report the highest NO_x emission rate obtained at any tested load level (average of three runs), except for units that use SCR or SNCR[41], and as otherwise noted below.

  - If the unit is an uncontrolled diffusion flame turbine, report the highest 3-run average NO_x emission rate obtained at any tested load, corrected to the average annual ambient conditions of temperature, pressure and relative humidity at the test site, using Equation LM-1a in §75.19.

  - For units equipped with SCR or SNCR:

  --- If the testing was done downstream of the SCR or SNCR, while these emission controls were *in operation*, report the higher of:

    - The highest 3-run average NO_x emission rate obtained at any tested load level; or
    - 0.15 lb/mmBtu

  --- If the testing was performed upstream of the SNCR or SNCR (or with the these controls *out-of-service*), and if the unit also uses water or steam injection or dry low-NO_x (DLN) technology to reduce NO_x emissions, and if the water injection, steam injection, or DLN technology was *in-service* during the testing, report the highest 3-run average emission rate at any

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[41] SCR and SNCR stand for selective catalytic reduction and selective non-catalytic reduction, respectively, which are post-combustion NO_x emission control technologies.

tested load level as the default NO_x emission rate.

- For a turbine that operates only at base load and peak load (or at two distinct set-point temperatures), report the 3-run average NO_x emission rate from the base load testing when the unit operates at base load, and report the 3-run average from the peak load testing when the unit operates at peak load. If testing was done only at base load, use a NO_x emission rate of 1.15 times the base load emission rate during peak load operation.

- For units that use add-on (post-combustion) NO_x controls of any kind and for units that use dry low-NO_x technology, report the appropriate generic default NO_x emission rate from Table LM-2 (§75.19) instead of the site-specific NO_x emission rate, for any unit operating hour in which the required parametric data (e.g., the water-to-fuel ratio) is unavailable or fails to document that the emission controls are working properly.

- For a group of identical LME units, follow the same basic rules as for single units, except that when it is appropriate to use the highest 3-run average NO_x emission rate, apply the highest 3-run average obtained at any tested load, for any tested unit, to all of the units in the group.

• **If the NO_x emission rate is based on historical CEMS data:**

- Use the 95^{th} percentile value from each fuel-specific data set as the default NO_x emission rate, with one exception—for units equipped with SCR or SNCR, if the 95^{th} percentile value is less than 0.15 lb/mmBtu, use 0.15 lb/mmBtu as the default NO_x emission rate.

6.1.6 What are the recordkeeping and reporting requirements for LME units ?

For a LME unit, the following essential records must be kept for three years, either on-site or (for unmanned facilities) at a central location:

- Records indicating which hours the unit operated and, for each of these hours, the unit operating time[38];
- The type(s) of fuel(s) combusted during each operating hour;
- The unit load during each operating hour (megawatts or klb/hr of steam), if long-term fuel flow is used to quantify heat input;
- Calculated hourly SO_2 , NO_x and CO_2 mass emissions (as applicable);
- The methods used to determine the hourly heat input values and the hourly NO_x emission rates;
- If the long-term fuel flow method is used , the quantity of each type of fuel combusted in each quarter, the GCV of each type of fuel, and the total quarterly

heat input; and

- For units with add-on NO_x emission controls or that use dry low-NO_x technology, records of the parametric data to verify proper operation of the emission controls (i.e., to justify using the site-specific NO_x emission rates).

All of the above information, except for the parametric data, must be reported quarterly to EPA in a standardized electronic data reporting (EDR) format. However, note that a data acquisition and handling system (DAHS) is not necessarily required to generate the quarterly EDR reports for an LME unit. EPA's Clean Air Markets Division has developed a special LME module within its Monitoring Data Checking (MDC) software, which is capable of generating quarterly EDRs for LME units[42].

6.1.7 What are the on-going QA/QC requirements for LME units ?

On-going quality-assurance is required for LME units only if the long-term fuel flow option is used for heat input and/or if site-specific emission rates are used to report emissions data. The quality control and quality-assurance (QA/QC) provisions that must be implemented are as follows:

- If site-specific NO_x emission rates are used for reporting, these emission rates must be re-determined every five years (20 calendar quarters);

- For gaseous fuels other than natural gas, annual sampling of the fuel's total sulfur content is required. The default SO_2 emission rate currently in use must be updated if the results of the annual sulfur sampling give an SO_2 emission rate that exceeds the current value.

- If site-specific emission rates are used for reporting purposes, records must be kept of all emission tests and/or data analyses used to determine the emission rates. These records are kept until the emission rates are re-determined;

- If the unit is equipped with add-on NO_x emission controls or dry low-NO_x technology, and if site-specific NO_x emission rates are used for reporting purposes, a quality-assurance plan must be developed and kept on-site, which explains the procedures used to document proper operation of the emission controls. The plan must clearly define all of the parameters monitored and the acceptable range(s) or value(s) for each parameter;

- Fuel billing records must be kept for three years, if that option is used for long-term fuel flow;

[42] Additional information on the LME module, in the form of a tutorial on CD-ROM, is available without cost at the following web address: www.epa.gov/airmarkets/monitoring/mdc/index.html

- If the tank drop method is used to quantify long-term oil flow, records must be kept for three years of all quarterly measurements, and a copy of the API method used must be kept on-file; and

- If a certified Appendix D fuel flowmeter is used for long-term fuel flow, the QA requirements in section 2.1.6 of Appendix D must be met (see Section 4.8 of this guide).

6.1.8 What happens if a low mass emissions unit loses its LME status ?

If, at the end of a calendar year or ozone season, it is determined that the emissions from an LME unit have exceeded the applicable threshold value(s) in Table 13, above, the unit's LME status is lost at that point. When this occurs, §75.19 requires Part 75-compliant continuous monitoring systems to be installed and certified for all parameters by December 31 of the calendar year following the year in which LME status is lost. For example, if an Acid Rain-affected LME unit emits 125 tons of NO_x in 2004, then Part 75 continuous monitoring systems must be installed and certified by December 31, 2005 [43]. To meet the Part 75 monitoring requirement, CEMS, fuel flowmeters, or the Appendix E methodology may be used, as appropriate. If the certification deadline is not met, maximum potential values and conservative emission factors must be used for reporting purposes until the certification tests are completed.

LME status can also be lost if a unit switches to a fuel other than oil or gas. In this case, the unit loses its LME status as of the first hour that the new fuel is combusted, and Part 75-compliant monitoring systems must be installed and certified prior to the fuel switch[44]. If the monitoring requirement is not met on-time, maximum potential values must be reported until the monitoring systems are certified.

6.2 Coal-Fired Units

The CAMR rule, which was published in the Federal Register on May 18, 2005, provides the blueprint for a mercury cap and trade program that will affect all 50 states. The program is scheduled to be implemented in 2009. The regulated units under CAMR are coal-fired EGUs that serve a generator > 25 megawatts. The rule, which has been codified as Subpart HHHH of 40 CFR Part 60, requires Hg mass emissions to be monitored according to Part 75.

However, prior to 2005, Part 75 did not have any Hg monitoring provisions. Therefore, as

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[43] Therefore, the LME methodology may be used for one more year or ozone season after LME status has been lost.

[44] Fuel switching is generally planned well in advance. This provides sufficient time to install and certify continuous monitoring systems.

part of the May 18, 2005 rulemaking, a new Subpart I was added to Part 75. Subpart I (§§75.80 -84) provides the necessary Hg mass emissions monitoring guidelines for the trading program.

The available Hg monitoring options are described in §75.81. For any affected unit in the program, the owner or operator may install and certify an Hg CEMS or a sorbent trap monitoring system to continuously monitor the Hg concentration. Both of these monitoring options require the use of a stack flow monitor to convert the measured Hg concentrations to mass emission rates. For sorbent trap systems and Hg CEMS that measure on a dry basis, a correction for the stack gas moisture content is also required.

For units with very low annual Hg mass emissions ($\leq$29 lb/yr), continuous monitoring of the Hg concentration is not required. For these low mass emissions units, Subpart I provides an alternative Hg monitoring methodology, which allows a conservatively high default Hg concentration to be reported for each unit operating hour (see §§75.81(b) through (f)). The default Hg concentration is based on the results of emission testing.

In order for a unit to qualify to use the low mass emissions methodology, the owner or operator must perform Hg emission testing prior to January 1, 2009, to determine the Hg concentration in the effluent gas stream. The testing consists of a minimum of three runs at the normal unit operating load. If the unit is equipped with flue gas desulfurization or add-on Hg emission controls, the controls must be operating normally during the testing.

Based on the results of the emission testing, the following equation is used to provide an estimate of the annual Hg mass emissions from the unit:

$$E = 8760\ K\ C_{Hg}\ Q_{max}$$

Where:

E	=	Estimated annual Hg mass emissions from the affected unit (ounces/year)
K	=	Units conversion constant, 9.978×10^{-10} oz-scm/μg-scf
8760	=	Number of hours in a year
C_{Hg}	=	The highest Hg concentration (μg/scm) from any of the test runs or 0.50 μg/scm, whichever is greater
Q_{max}	=	Maximum potential flow rate, determined according to section 2.1.4.1 of Part 75, Appendix A (scfh)

This equation gives a very conservative estimate of the annual Hg emissions. It assumes that the unit operates year-round at its maximum potential flow rate. If the highest Hg concentration measured in any of the test runs is less than 0.50 μg/scm, a default value of 0.50 μg/scm must be used in the calculations. Note also that this methodology does not require a correction for the stack gas moisture content.

If the estimate of the annual Hg mass emissions obtained from the equation above is 464 ounces per year or less (i.e., ≤ 29 lb/yr), then the unit is eligible to use the low mass emissions methodology, and continuous monitoring of the Hg concentration is not required. For each qualifying low mass emissions unit, the owner or operator must submit the results of the Hg emission testing to the Administrator and to the permitting authority, no later than 45 days after the testing is completed. The calculations demonstrating that the unit emits 464 ounces (or less) per year of Hg must also be provided, and the default Hg concentration that will be used for reporting must be specified. The regulatory agencies will treat the submittal as a certification application, and the methodology will be considered to be provisionally certified as of the date and hour of completion of the Hg emission testing.

Following initial certification, the same default Hg concentration value that was used to estimate the unit's annual Hg mass emissions is reported for each unit operating hour. The default Hg concentration value must also be updated periodically, based on the results of additional required emission testing. Re-testing is required either semiannually or annually, depending on the results obtained in the previous test. If the estimated annual Hg emissions from the previous test are ≤144 ounces/year (9 lb/yr), the retest frequency is annual and the next test is due in four "QA operating quarters" (see footnote 63, below). If the estimated annual emissions exceed 9 lb/yr, the retest frequency is semiannual and the next test is due in two QA operating quarters.

If the low mass emissions unit is equipped with a flue gas desulfurization system or add-on Hg controls, the owner or operator must record the appropriate parametric data or SO_2 emission data for each unit operating hour, to document proper operation of the emission controls. For any unit operating hour in which this documentation is unavailable, the maximum potential Hg concentration must be reported.

The low mass emissions methodology may be used for reporting Hg mass emissions at common and multiple stack configurations, if the following conditions are met.

- For a common stack, all units using the stack must be CAMR affected units and each unit must be tested individually to demonstrate that it emits ≤ 464 ounces of Hg per year. If these conditions are met, the default Hg concentration used for reporting at the common stack will either be the highest value obtained in any test run for any of the units serving the common stack or 0.50 μg/scm, whichever is greater.

- For units with multiple stack or duct configurations, Hg emission testing must be performed separately on each stack or duct, and the sum of the estimated annual Hg mass emissions from the stacks or ducts must not exceed 464 ounces of Hg per year. For reporting purposes, the default Hg concentration used for each stack or duct will either be the highest value obtained in any test run for that stack or 0.50 μg/scm, whichever is greater.

- For units with a main stack and bypass stack configuration, Hg emission testing is performed only on the main stack. For reporting purposes, the default Hg concentration used for the main stack will either be the highest value obtained in any test run or 0.50 μg/scm, whichever is greater. Whenever the main stack is bypassed, the maximum potential Hg concentration must be reported.

At the end of each calendar year, if the cumulative annual Hg mass emissions from a low mass emissions unit have exceeded 464 ounces, the owner must install, certify, operate, and maintain a Hg concentration monitoring system or a sorbent trap monitoring system within 180 days after the end of the calendar year in which the annual Hg mass emissions exceeded 464 ounces. For common stack and multiple stack configurations, installation and certification of a Hg concentration or sorbent trap monitoring system on each stack (except for bypass stacks) is likewise required within 180 days after the end of the calendar year, if:

- The annual Hg mass emissions at the common stack have exceeded 464 ounces times the number of affected units using the common stack; or

- The sum of the annual Hg mass emissions from all of the multiple stacks or ducts has exceeded 464 ounces; or

- The sum of the annual Hg mass emissions from the main and bypass stacks has exceeded 464 ounces.

7.0 PART 75 MONITORING SYSTEM CERTIFICATION PROCEDURES

7.1 How are Part 75 monitoring systems certified ?

Before any data from Part 75 monitoring systems can be reported as quality-assured, the systems must pass a series of certification tests, to demonstrate that they are capable of providing accurate emissions data. The overall monitoring system certification process consists of several steps, as shown in Figure 3. The requirements of each certification step are discussed in detail, below. Note that for low mass emissions (LME) units, the certification process is somewhat different, and therefore is discussed separately in section 6 of this guide.

7.2 Step 1—Submit an Initial Monitoring Plan

For each affected unit, an initial monitoring plan must be submitted at least 45 days prior to the start of the certification testing of the monitoring systems. The monitoring plan identifies the overall monitoring strategy for each unit. The plan must contain sufficient information about the monitoring systems to demonstrate that all of the regulated emissions from the unit will be measured and reported. The monitoring plan consists of two parts:

- ***Electronic***, which includes the following information, arranged in EPA's standard electronic data reporting (EDR) format:
  - Unit information, such as the unit type, the maximum heat input capacity, the operating range of the unit (in terms of megawatts or steam load), the type(s) of fuel combusted, the type(s) of emission controls, etc;
  - Unit-stack configuration information, indicating how the effluent gases from the unit discharge to the atmosphere--- i.e., through a single stack or multiple stacks, or through a common stack shared with other units;
  - A description of the methodology used to monitor each pollutant or parameter (e.g., CEMS, Appendix D, Appendix E, etc.).
  - Monitoring system information, e.g., the pollutant or parameter monitored by the system, the make, model and serial number of each analyzer, etc;
  - Mathematical formulas used to calculate emissions and heat input; and
  - Analyzer span and range information;

- ***Hard copy***, which includes supplemental information that is incompatible with EDR format, such as:
  - Schematic diagrams and blueprints;
  - Data flow diagrams;

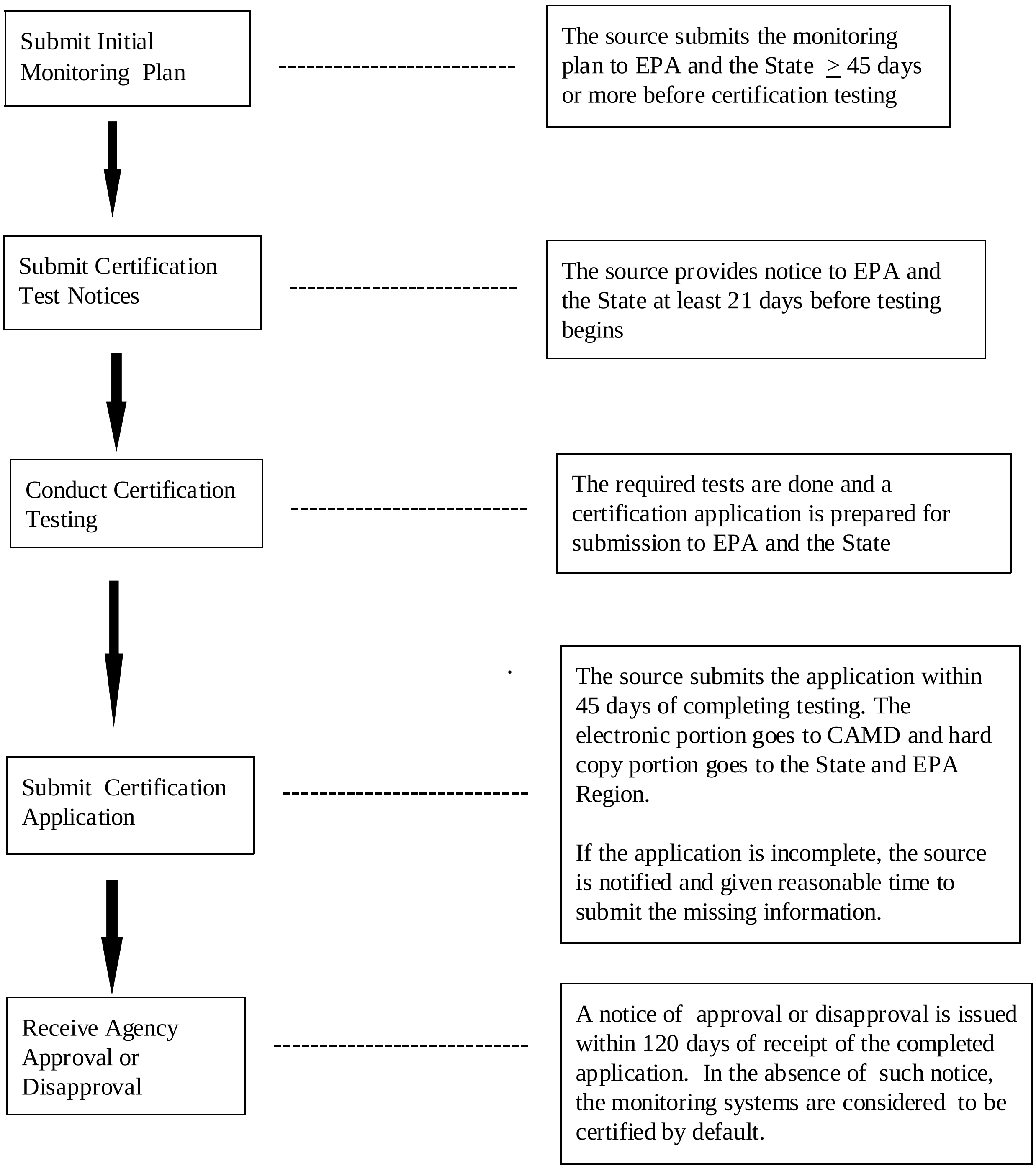

Figure 3: Monitoring System Certification Process

- Test protocols;
- Technical justifications; and
- Special documentation (e.g., fuel sampling data, vendor guarantees, etc.)

The electronic portion of the monitoring plan must be sent to the EPA Clean Air Markets Division (CAMD)[45], and the hard copy portion goes to the EPA Regional Office and to the State Agency. CAMD uses its Monitoring Data Checking (MDC) software to evaluate the electronic portion of the monitoring plan and sends feedback to the source, to the State, and to the EPA Region. The State and EPA Regional Offices then review the hard copy piece of the monitoring plan, together with the feedback from CAMD on the electronic portion. The reviewing agencies communicate their findings to the source and help to resolve any issues or deficiencies identified during the review process.

The monitoring plan is a "living"document, in that it must be continuously updated to reflect changes to the monitoring systems over time. As technology advances, the monitors originally described in the monitoring plan may be replaced, or the monitoring methodology may be changed. Also, facility operations may change and necessitate the use of additional monitors or alternative placement of existing monitors. Therefore, for any modification, replacement, or other change to an approved monitoring system or monitoring methodology, the monitoring plan must be updated. For example, replacing a gas analyzer requires a monitoring plan update, because Part 75 requires the make, model and serial number of each analyzer to be reported.

Note that Part 75 allows all of the monitoring plan information, including the hard copy portion, to be stored electronically, provided that a paper copy can be furnished to an inspector or auditor upon request.

7.3 Step 2—Submit Certification Test Notices

Certification test notices must be sent to CAMD, to the EPA Regional Office and to the appropriate State or local air agency, at least 21 days prior to conducting the required certification testing. There is one exception to this--- for the certification of Appendix D fuel flowmeters, the notifications are not required.

7.4 Step 3—Conduct Certification Testing

The types of certification tests required for Part 75 monitoring systems are described below:

- **7-day calibration error test**--- Evaluates the accuracy and stability of a gas or flow monitor's calibration over an extended period of unit operation.

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[45] See the following web address— http://www.epa.gov/airmarkets/monitoring/arp/monplanemail.html

- **Linearity check**—Determines whether the response of a gas monitor is linear across its range
- **System integrity check**—For a mercury CEMS equipped with a converter, this test verifies that the converter is working properly
- **RATA**--- Compare emissions data recorded by a CEMS to data collected concurrently with an EPA emission test method.
- **Bias test**—Determines whether a monitoring system is biased low with respect to the reference method, based on the RATA results. If a low bias is found, a bias adjustment factor (BAF) must be calculated and applied to the subsequent hourly emissions data. This test is required only for SO_2, NO_x, Hg, and flow monitoring systems.
- **Cycle time test**—Determines whether a gas monitoring system is capable of completing at least one cycle of sampling, analyzing and data recording every 15 minutes.
- **Flowmeter Accuracy test**—Demonstrates that a fuel flowmeter can accurately measure the fuel flow rate over the normal operating range of the unit.
- **Four-load NO_x emission rate testing and heat input measurement**–Provides data for a correlation curve of NO_x emission rate vs. heat input rate for an Appendix E peaking unit.
- **NO_x emission rate testing at one or more unit loads**—Determines fuel-and unit-specific NO_x emission factors for LME units (optional).
- **DAHS verification**—Ensures that all emissions calculations are being performed correctly and that the missing data routines are being applied properly.

The specific certification tests required for each Part 75 monitoring system are shown in Table 14. For the test procedures that must be followed, see the following sections of Part 75:

- For CEMS---Section 6 of Appendix A.
- For fuel flow meters---Section 2.1.5 of Appendix D.
- For Appendix E testing---Section 2.1 of Appendix E.
- For the data acquisition and handling system---§75.20(c)(9)

Table 14: Required Certification Tests for Part 75 Monitoring Systems

To certify this type of monitoring system.	These tests must be performed.	With the following exceptions and qualifications. . . .
SO_2 or NO_x concentration	• 7-day calibration error test. • Linearity check. • RATA (ppm basis) • Bias test. • Cycle time test. • DAHS verification.	• Peaking units and SO_2 and NO_x span values $\leq$ 50 ppm are exempted from the 7-day calibration error test • SO_2 and NO_x span values $\leq$ 30 ppm are exempted from linearity checks • SO_2 monitor is exempt from RATA if the unit burns only "very low-sulfur fuel" or combusts higher-sulfur fuel for $\leq$ 480 hours per year
NOx- diluent	• 7-day calibration error test (each analyzer). • Linearity check (each analyzer). • RATA (lb/mmBtu basis). • Bias test. • Cycle time test (each analyzer). • DAHS verification.	• Peaking units and NO_x span values $\leq$ 50 ppm are exempted from the 7-day calibration error test • NO_x span values $\leq$ 30 ppm are exempted from linearity checks
Stack gas flow rate	• 7-day calibration error test. • RATA (3-load) • Bias test. • DAHS verification.	• Peaking units are exempted from the 7-day calibration error test • Only single-load RATAs are required for flow monitors on peaking units and bypass stacks
CO_2 or O_2 concentration	• 7-day calibration error test. • Linearity check. • RATA • Cycle time test. • DAHS verification.	• Peaking units are exempted from the 7-day calibration error test
Hg concentration CEMS	• 7-day calibration error test • Linearity check • 3-level system integrity check • Cycle time test • RATA • Bias test • DAHS verification	• The 7-day calibration error test may be done with elemental Hg or a NIST-traceable source of oxidized Hg • The linearity check must be done with elemental Hg standards • The system integrity check is only required for CEMS with converters

Table 14 (cont'd)

To certify this type of monitoring system.	These tests must be performed.	With the following exceptions and qualifications. . . .
Sorbent trap monitoring system	• RATA • Bias test • Appendix K quality-assurance procedures • DAHS verification	• No exceptions
Moisture system with wet and dry O_2 analyzers(s)	• 7-day calibration error test (each analyzer). • Linearity check (each analyzer). • RATA (% H_2O basis). • Cycle time test (each analyzer). • DAHS verification.	• Peaking units are exempted from the 7-day calibration error test
Continuous moisture sensor	• RATA (% H_2O basis) • DAHS verification.	• No exceptions
Continuous moisture system consisting of a temperature sensor and a DAHS with a "lookup table"	• Demonstration that the DAHS applies the correct moisture value from the lookup table at 3 representative temperatures. This option applies to saturated gas streams, only.	• No exceptions
Appendix D fuel flowmeter system	• Flowmeter Accuracy test • DAHS verification.	• Qualifying billing meters
Appendix E NO_x system	• NO_x emission rate testing and Appendix D heat input measurement at 4 unit loads • DAHS verification	• Emergency fuel (testing optional)

7.5 Step 4—Submit Certification Application

Within 45 days after completing the required certification testing, a certification application must be submitted. There are two parts to the application---electronic and hard copy.

- The electronic part of the application consists of a complete, updated monitoring plan and the results of the certification tests, in EDR format. This part of the application is sent to CAMD[46].

[46] See the following web address: http://www.epa.gov/airmarkets/monitoring/arp/certemail.html

- The hard copy part of the application consists of an application form, the hard copy certification test report, and any changes made to the hard copy portion of the monitoring plan as a result of the testing. This part of the application is sent to the EPA Regional Office and to the appropriate State or local agency.

If the certification application is incomplete or is missing any information, the reviewing agencies will notify the source, and a reasonable amount of time will be given to submit the required information. A 120-day review period begins when a complete certification application has been received.

7.6 Step 5—Receive Agency Approval or Disapproval

The appropriate reviewing agency[47] will issue a notice of approval or disapproval of the certification application within 120 days of receiving the complete application. While the application is pending, the monitoring systems are considered to be "provisionally certified". This means that data from the monitoring systems are considered to be quality-assured, beginning at the date and hour of completion of the certification tests[48], and continuing throughout the 120-day review period, provided that:

- The monitoring systems are operated in accordance with all applicable Part 75 requirements; and
- A notice of disapproval of the application is not issued in the meantime.

If the reviewing agency fails to provide notice of approval or disapproval of the application by the end of the 120 day review period, then, provided that all required tests were successfully completed, the monitoring systems are considered to be certified by default. During any period that the monitoring systems are not provisionally or officially certified, the Part 75 missing data procedures must be used to estimate emissions (see Section 9 of this guide).

7.7 What reference test methods and standards are used for certification testing?

Various test methods, some of which have been developed by EPA and others by reputable standards organizations such as ASME, are used to certify Part 75 monitoring systems. In addition, high-quality calibration gases are used in many of the certification tests. These test methods and calibration standards are discussed below.

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[47] For the Acid Rain Program, the notice is issued by EPA. For the NO_x Budget Program, the notice is issued by the State or local agency.

[48] Note that if the "conditional data validation" procedures in §75.20(b)(3) are used, the date of provisional certification will be earlier than the date on which the certification tests are completed (see section 9.5 of this guide).

Calibration Gases

The certification tests of Part 75 gas monitoring systems require the use of calibration gases, either to calibrate the CEMS (e.g., for 7-day calibration error tests and linearity checks) or to calibrate the reference method analyzers that are used for RATAs. The calibration gas cylinders used for these tests are special gas mixtures that have been prepared using a standard EPA protocol[49]. These protocol gas mixtures consist of known concentrations of the pollutant or diluent gases of interest (e.g., SO_2, NO_x, CO_2, etc.), in a non-reactive gas such as nitrogen.

To be acceptable for use in Part 75 applications, a cylinder gas must meet the definition of "calibration gas" in section 5 of Appendix A, and must be traceable to standard reference materials prepared by the National Institute of Standards and Technology (NIST). The only exception to this is purified instrument air, which may be used as a zero gas or as an upscale calibration material for O_2 analyzers.

EPA Reference Methods

Part 75 requires periodic relative accuracy test audits (RATAs) of all CEMS, both gas and flow monitoring systems. The RATA compares data from the CEMS to measurements made with an EPA test method (known as a "reference method"). Reference methods are also used for Appendix E NO_x emission testing and to determine fuel- and unit-specific NO_x emission rates for LME units. Except for the Ontario-Hydro method, which is an ASTM method, the EPA reference test methods are found in Appendices A-1 through A-7 of 40 CFR Part 60. The specific method(s) used for various Part 75 applications are summarized in Table 15.

Fuel Flowmeter Accuracy Standards

Part 75 sources using Appendix D methodology are required to continuously monitor the fuel flow rate. With few exceptions, certified fuel flowmeters are used for this purpose. Fuel flowmeters are certified using test methods or, in some cases, design specifications, that have been published by consensus standards organizations such as ASME, AGA, and API. See section 4 of this guide for further discussion.

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[49] "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards" September, 1997, EPA-600/R-97/121.

Table 15 : EPA Reference Test Methods Used in Part 75 Applications

This EPA Reference Method[a].....	Or its Allowable Alternatives[b]....	Is Used to	In these Part 75 Applications.....
Method 1	Method 1A	Locate traverse points for flow rate measurement	Flow monitor RATAs
Method 2	Methods 2F, 2G, 2H and CTM-041[c]	Measure stack gas volumetric flow rate	Flow monitor RATAs
Method 3A	Methods 3, 3B	Measure diluent gas (O_2 or CO_2) concentrations	RATAs of: • NOx-diluent monitoring systems • CO_2 or O_2 monitoring systems • Flow monitors[d] Appendix E tests LME unit tests
Method 4	Wet bulb-dry bulb technique[d]	Measure the moisture content of stack gas	RATAs of: • Moisture monitoring systems • Flow monitors[d] • Certain gas monitors[e]
Method 6C	Methods 6,6A, 6B	Measure SO_2 concentration	SO_2 monitor RATAs
Method 7E	Methods 7, 7A, 7C, and 7D	Measure NO_x concentration	RATAs of NO_x monitoring systems Appendix E tests LME unit tests
Method 20	--------	Measure NO_x and diluent gas concentrations (gas turbines, only)	Appendix E tests LME unit tests

Table 15 (cont'd)

This EPA Reference Method[a].....	Or its Allowable Alternatives[b]....	Is Used to	In these Part 75 Applications.....
Ontario Hydro Method	Instrumental RM approved by the Administrator[f]	Measure Hg concentration	RATAs of Hg CEMS and sorbent trap monitoring systems

a. These reference methods are found in Appendices A-1 through A-7 in 40 CFR Part 60

b. Methods 3A, 6C and 7E are instrumental methods. Their allowable alternatives are wet-chemistry methods and are seldom, if ever, used because the results of the RATA (and hence, the quality-assured status of the CEM data) cannot be known until the laboratory analyses of the samples are completed.

c. Methods 2F and 2G correct the measured flow rates for angular (non-axial) flow. Method 2H (for circular stacks) and conditional test method CTM-041 (for rectangular stacks and ducts) are used to correct the measured flow rates for velocity decay near the stack wall, using a "wall effects adjustment factor" (WAF).

d. Molecular weight (MW) determinations are required in all flow RATAs. Measurements of diluent gas concentration and stack gas moisture content are needed to calculate the MW. Use of the wet bulb-dry bulb technique is restricted to these molecular weight determinations.

e. When the CEMS and reference method measure on a different moisture basis, moisture corrections are required.

f. At the present time, EPA is developing an instrumental reference method for Hg

7.8 What performance specifications must be met for certification?

For a Part 75 CEMS, the performance specifications that must be met for initial certification are found in section 3 of Appendix A. These specifications are summarized in Table 16. Table 16 shows that for certain tests, there is an alternative performance specification in addition to the principal, or main specification. Generally speaking, the purpose of the alternative specifications is to provide regulatory relief in cases where the main specification may be too stringent. For example, for a source with low SO_2 emissions, an SO_2 monitor may have difficulty meeting the principal relative accuracy standard of 10.0%, but might be able to meet the alternative specification, which is a mean difference of 15 ppm or less between the CEMS and reference method.

For fuel flowmeters, the basic accuracy specification that must be met is 2.0% of the full-scale, or "upper range value" (URV) of the flowmeter. For flowmeters that are calibrated with a flowing fluid (e.g., in a laboratory), this accuracy specification must be met at three points across the normal measurement range of the instrument, i.e., covering the actual range of fuel flow rates that the meter will be used to measure. For flowmeters that are certified by design (such as orifice meters), the 2.0% of URV accuracy standard is considered to be met if the primary element passes a visual inspection, and each of the pressure, temperature and differential pressure transmitters is calibrated at 3 points or "levels" (low, mid and high) across its normal measurement range, using NIST-traceable equipment, and if:

- The accuracy of each transmitter is 1.0% of full-scale (or less) at each level; or
- If, at a particular level, the sum of the accuracies of the three transmitters is 4.0% or less.

Table 16: Performance Specifications for Part 75 Continuous Monitoring Systems

For this certification test.....	On this type of monitor or monitoring system.....	The main performance specification[a] is.....	The alternate performance specification is.....	And the conditions of the alternate specification are.....
7-day calibration error test	SO_2 or NO_x	± 2.5% of span value, on each of the 7 days	$\lvert R - A \rvert \leq 5$ ppm	Span value < 200 ppm
	Flow	± 3.0% of span value, on each of the 7 days	$\lvert R - A \rvert \leq 0.01"H_2O$	Applies only to DP-type flow monitors
	CO_2 or O_2	$\lvert R - A \rvert \leq 0.5\%$ CO_2 or O_2, on each of the 7 days	----------------	--------------
	Hg CEMS	± 5.0% of span value, on each of the 7 days	$\lvert R - A \rvert \leq 1.0$ µg/scm	Span value equal to 10 µg/scm
Linearity check	SO_2 or NO_x	$\lvert R - A_{avg} \rvert \leq 5.0\%$ of the reference gas tag value, at each calibration gas level	$\lvert R - A_{avg} \rvert \leq 5$ ppm	The alternate specification may be used at any gas level
	CO_2 or O_2	$\lvert R - A_{avg} \rvert \leq 5.0\%$ of the reference gas tag value, at each calibration gas level	$\lvert R - A_{avg} \rvert \leq 0.5\%$ CO_2 or O_2	The alternate specification may be used at any gas level
	Hg CEMS	$\lvert R - A_{avg} \rvert \leq 10.0\%$ of the reference gas tag value, at each calibration gas level	$\lvert R - A_{avg} \rvert \leq 1.0$ µg/scm	The alternate specification may be used at any gas level

Table 16 (cont'd)

For this certification test.....	**On this type of monitor or monitoring system.....**	**The main performance specification[a] is.....**	**The alternate performance specification is.....**	**And the conditions of the alternate specification are.....**
Cycle time test	All gas monitoring systems	15 minutes	----------------------	---------------
System integrity check	Hg CEMS with converters	$\lvert R - A_{avg} \rvert \leq$ 5.0% of the span value, at each calibration gas level	-----------------------	----------------
RATA	SO_2 or NO_x concentration	10.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq$ 15.0 ppm[b]	$RM_{avg} \leq$ 250 ppm
	NO_x -diluent	10.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq$ 0.020lb/mmBtu	$RM_{avg} \leq$ 0.200 lb/mmBtu
	Flow	10.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq$ 2.0 ft/sec	$v_{avg} \leq$ 10.0 ft/sec
	CO_2 or O_2	10.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq$ 1.0% CO_2 or O_2	-----------
	Moisture	10.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq$ 1.5% H_2O	--------
	Hg CEMS and sorbent trap monitoring systems	20.0% RA	$\lvert RM_{avg} - C_{avg} \rvert \leq$ 1.0 µg/scm	$RM_{avg} \leq$ 5.0 µg/scm
Flowmeter accuracy test	Fuel flowmeters	2.0% of full-scale, i.e., the upper range value (URV)	T, P and ΔP transmitters are accurate to 1.0% at each of three levels, or have a combined accuracy ≤ 4.0% at any level	Alternate specification applies only to orifice, nozzle and venturi meters

[a] Note that $\lvert R - A \rvert$ is the absolute value of the difference between the reference gas (or signal) value and the analyzer reading. $\lvert R - A_{avg} \rvert$ is the absolute value of the difference between the reference gas concentration and the average of the analyzer responses, at a particular gas level.

[b] Note that $\lvert RM_{avg} - C_{avg} \rvert$ is the absolute difference between the mean reference method value and the mean CEMS value from the RATA. Thus, the arithmetic difference between RM_{avg} and C_{avg} can be either + or -.

7.9 What is meant by the "span value", and why is it important ?

The "span value" is an important concept in Part 75, for several reasons:

- It provides a basis for selecting the full-scale measurement range of a continuous monitor;
- It is used to define the upscale calibration gases (or calibration signals) that are used for daily calibrations, linearity checks, and system integrity checks of Hg monitors;
- The principal performance specifications for daily calibration error checks of SO_2, NO_x, Hg, and flow monitors are expressed as a percentage of the span value; and
- The performance specification for system integrity checks of Hg monitors is expressed as a percentage of the span value.

The span value is a reasonable estimate, or "educated guess" of how large an analyzer scale (i.e., range) is needed to accurately record the emissions or flow rate data at a particular monitored location. For each parameter monitored (e.g., SO_2 , NO_x, Hg, flow), Part 75 requires a high span value and a corresponding full-scale measurement range to be defined in the monitoring plan. For gases, the high span value is based on the maximum potential concentration, or MPC. For flow, the span value is based on the maximum potential flow rate, or MPF.

These maximum potential values can be determined in a number of different ways. For instance, depending on which gas is being monitored, the MPC may either be a "generic" default value prescribed in Part 75, or it may be based on historical fuel sampling data, emission test results, or historical CEM data. The MPF may either be estimated using Equation A-1a or A-1b in Appendix A of Part 75, or may be derived from measurements of stack gas velocity at maximum load.

Once the MPC or MPF has been determined, the high span value is set by multiplying the MPC or MPF by a factor of 1.00 to 1.25, and rounding off the result appropriately[50]. Thus, the span value may either be set equal to or slightly higher than the maximum potential value. After determining the span value, the full-scale range of the monitor must be set. Part 75 requires the range to be greater than or equal to the span value. However, note that when setting the range, the guidelines in section 2.1 of Appendix A should be taken into account, to avoid setting it too high. According to section 2.1, the range should (with certain exceptions, described below) be selected to ensure that the majority of the data fall between 20% and 80% of full-scale.

For many Part 75 units, the use of high span values and full-scale ranges derived from the

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[50] Except for Hg CEMS. For an Hg monitor, the span value is determined by rounding the MPC upward to the next highest multiple of 10 μg/scm. In other words, the MPC multiplication factor is always 1.00 and the Hg span value is always a multiple of 10 μg/scm.

maximum potential values is sufficient to ensure that data are accurately recorded. However, for units with add-on SO_2, NO_x, or Hg emission controls, or for units that burn multiple fuels with distinctly different SO_2 or NO_x emission rates, it may be necessary to define a second, low span value and a low range. A low span and range will be required if the emission levels are expected to be consistently below 20% of the high range[51] when the add-on emission controls are operating properly, or when the lowest-emitting fuel is burned.

If a second span and range are required, the low span value is set in a similar manner to the high span value. The only difference is that the low span is based on the maximum expected concentration (MEC), rather than the MPC. The MEC is the highest that the concentration of the pollutant is expected to be when the add-on controls are in normal operation or when the lowest-emitting fuel is combusted. There are a number of ways to determine the MEC. For units with add-on emission controls, it may be based on the expected efficiency of the controls. Emission test data, historical CEM data, or an emission limit in the operating permit may also be used to determine the MEC. Once the MEC has been established, the low span value is calculated by multiplying the MEC by a factor of 1.00 to 1.25 and rounding off the result appropriately[52]. Then, the low range is set greater than or equal to the low span value.

Note that for units with dual SO_2 or NO_x spans, Part 75 allows a "default high range value" to be reported when the emissions go off the low scale, as an alternative to maintaining and calibrating a high monitor range. But the default high range value is a very high number (200% of the MPC) and grossly overstates the emissions. Therefore, this option is probably not a good one except for sources whose emissions rarely, if ever, exceed the full-scale of the low range. Note also that for dual-span units there are exceptions to the "20-to-80% of range" guideline in section 2.1 of Appendix A. For instance, provided that the low span and range have been set according to the rule, the low range is exempted from this guideline. And if the add-on emission controls are operated year-round, the high range is similarly exempted.

An unusual feature of Part 75 is that for flow monitors, there is only one measurement range, but there are two span values— the "calibration span value" and the "flow rate span value". These two span values are both derived from the MPF and are actually equivalent, but almost invariably they are expressed in different units of measure. The calibration span value is the one used for daily calibrations of the flow monitor. Often it is expressed in units such as inches of water (in. H_2O) or thousands of standard cubic feet per minute (kscfm), depending on the type of flow monitor. The flow rate span value is always in units of standard cubic feet per hour (scfh), which are the units of measure prescribed by Part 75 for reporting hourly stack gas flow rates.

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[51] For Hg monitors, a second range is needed only if the high range value is $\geq$ 20 μg/scm and if the expected emission levels with the emission controls in proper operation are $\leq$ 20% of that value. For some units, an SO_2 scrubber produces a co-benefit of significantly reducing Hg emissions.

[52] Except for Hg CEMS. For an Hg monitor, the low span value is always set to 10 μg/scm.

Once the span values for all of the required continuous monitors have been established, these values are used for daily calibration assessments, Hg monitor system integrity checks, and linearity checks, as follows:

- For the daily calibrations of gas monitors, zero and upscale gases are used. The zero gas must be 0 to 20% of the span value, and the upscale gas may be either a mid level gas (defined as 50 to 60% of the span value) or a high level gas (80 to100% of the span value).

- For the daily calibrations of flow monitors, a zero calibration signal (0 to 20% of the calibration span value) and an upscale calibration signal (50 to 70% of the calibration span value) are used.

- For weekly system integrity checks of Hg CEMS, a mid-level or high-level calibration standard, with a concentration of 50 to 60% or 80 to 100% of the span value, is required.

- For linearity checks of gas monitors and 3-level system integrity checks of Hg CEMS, calibration is required at three different gas levels (low, mid, and high), using calibration standards with concentrations of 20 to 30%, 50 to 60%, and 80 to 100% of the span value, respectively.

- The principal performance specification for certain daily calibration error tests are expressed as a percentage of the span value. For an SO_2 , NO_x , or Hg monitor, the performance specification is $\pm$ 5.0% of the span value, and for a flow monitor, it is $\pm$ 6.0% of the calibration span value; and

- The performance specification for single- and 3-level system integrity checks of Hg monitors is 5.0% of the span value.

Finally, Part 75 requires periodic evaluations (at least once a year) of the MPC, MEC, span and range values. These evaluations are done by reviewing the emissions and flow rate data from the previous four quarters. If any of the MPC, MEC, span and/or range values are found to be improperly set, the necessary adjustments must be made within 45 days (or within 90 days if new calibration gases must be ordered) after the end of the quarter in which this is discovered.

7.10 Recertification and Diagnostic Testing

Whenever a replacement, modification, or other change is made to a monitoring system that may affect the ability of the system to accurately measure emissions, the system must be recertified. Also, changes to the flue gas handling system or manner of unit operation that affect the flow profile or the concentration profile in the stack may trigger recertification. Examples of situations that require recertification of Part 75 monitoring systems include:

- Replacement of an analyzer.
- Replacement of an entire CEMS.
- Change in location or orientation of a sampling probe
- Fuel flow meter replacement.
- Exceedance of Part 75 Appendix E operating parameters for more than 16 consecutive operating hours

The requirements for recertification are basically the same as those shown in Figure 3, above, for initial certification. A recertification application must be submitted within 45 days of completing the required tests and a 120-day period is allotted for the regulatory agencies to review the application. However, note that for recertifications, an initial monitoring plan submittal is not required, and the test notification requirements are slightly different from those for initial certification.

Not all changes made to a certified monitoring system require recertification. In many cases, only diagnostic testing is required to ensure that the system continues to provide accurate data. Note also that in some instances EPA requires less than a full battery of tests for recertification. For a more thorough discussion of recertification and diagnostic testing, see §75.20(b) and Questions 13.21 and 16.14 through 16.16 in EPA's "Part 75 Emissions Monitoring Policy Manual"[53].

[53] The Policy Manual is located at: http://www.epa.gov/airmarkets/monitoring/polman/index.html

8.0 QUALITY ASSURANCE and QUALITY CONTROL (QA/QC) PROCEDURES

8.1 Does Part 75 require periodic quality QA/QC testing after a monitoring system is certified ? If so, where are these test requirements found ?

Following initial certification, all Part 75 monitoring systems are required to undergo periodic quality-assurance testing, to ensure that they continue to provide accurate data.

- For CEMS, the QA test requirements are found in either:
  - Appendix B of Part 75 and §75.21, for sources that report emissions data year-round; or
  - Section 75.74(c), for NO_x Budget Program or CAIR Ozone Season Trading Program sources that report emissions data only during the ozone season, from May 1st through September 30th;
- For sorbent trap monitoring systems, the QA requirements are found in Appendices B and K of Part 75;
- For Appendix D fuel flowmeter systems, the on-going QA test requirements are in section 2.1.6 of Appendix D; and
- For Appendix E NO_x correlation curve systems, the QA requirements are found in sections 2.2 and 2.3 of Appendix E.

8.2 What are the on-going QA test requirements in Part 75 for units reporting emissions data year-round?

Year-round reporting of emissions data is required for all Acid Rain Program units, all CAIR SO_2 Trading Program units, and for certain NO_x Budget Program and CAIR NO_x Trading Program units (see Section 8.5, below). For CEMS, the on-going QA test requirements for year-round reporters are summarized in Table 17. Table 17 shows that routine QA testing of CEMS is required at four basic frequencies:

- Daily;
- Weekly;
- Quarterly; and
- Semiannual or Annual.

Calibration error checks of all monitors and interference checks of flow monitors are required daily. For Hg CEMS with converters, system integrity checks are required weekly. Gas monitor linearity checks, flow-to-load ratio tests, and leak checks (for DP-type flow monitors) are required quarterly. RATAs are required either semiannually or annually, depending on the type of monitor and/or the results of the tests (see Section 8.6, below).

For Appendix D fuel flowmeters, the basic frequency for the required accuracy tests is annual. For Appendix E systems, NO_x emission testing is required once every five years, in order to develop new correlation curves.

Table 18 summarizes the on-going QA requirements for sorbent trap monitoring systems.

Table 17: On-Going QA Test Requirements for Year-Round Reporters

Perform this type of QA test....	On these continuous monitoring systems....	At this frequency....	With these qualifications and exceptions....
Calibration error test	Gas and flow monitors	Daily	• Calibrations are not required when the unit is not in operation.
Interference check	Flow monitors	Daily	• Check is not required when the unit is not in operation.
System integrity check (single-level)	Hg CEMS with converters	Weekly[a]	• Not required if daily calibrations are done with a NIST-traceable source of oxidized Hg
Linearity check	Gas monitors	Quarterly	• Required only in "QA operating quarters"[b] and only on the range(s) used during the quarter---but no less than once a year • 168 operating hour grace period available • Not required if SO_2 or NO_x span is $\leq$ 30 ppm • For Hg monitors, you may perform a 3-level system integrity check using oxidized Hg standards, in lieu of this test
System integrity check (3-level)	Hg CEMS with converters	Quarterly	• For Hg monitors, you may perform a linearity check using elemental Hg standards, in lieu of this test
Flow-to-load ratio or gross heat rate test	Flow monitors	Quarterly	• Required only in "QA operating quarters" • Non load-based units are exempted • Complex configurations may be exempted by petition under §75.66
Leak check	Differential pressure-type flow monitors	Quarterly	• Required only in QA operating quarters • 168 operating hour grace period available

Table 17 (cont'd)

Perform this type of QA test....	On these continuous monitoring systems....	At this frequency....	With these qualifications and exceptions....
RATA and Bias test	Gas and flow monitors (Bias test applies to SO_2, NO_x, Hg, and flow monitoring systems, only)	Semiannual or Annual[c]	• Not required for SO_2 monitors if the unit exclusively burns very low sulfur fuel, or burns higher-sulfur fuel for $\leq$ 480 hours per year • 720 operating hour grace period available • For Hg monitoring systems, the RATA frequency is always annual
Flowmeter Accuracy test	Fuel flowmeter systems	Once every four "fuel flowmeter QA operating quarters"[d]	• The optional "fuel flow-to-load ratio" or "gross heat rate" test in Appendix D, section 2.1.7 may be used to extend the interval between flowmeter accuracy tests to up to 20 quarters
Primary element visual inspection	Orifice, nozzle, and venturi-type fuel flowmeters that are certified by design	Once every 3 years (12 calendar quarters)	• The optional fuel flow-to-load ratio or gross heat rate test may be used to extend the interval between visual inspections to up to 20 quarters
NO_x emission rate testing	Appendix E systems	Once every 5 years (20 calendar quarters)	-----------

[a] "Weekly" means once every 168 unit operating hours

[b] That is, a quarter with at least 168 hours of unit operation

[c] Depending on the % relative accuracy obtained in the previous test, the next RATA is required either "semiannually" (within 2 QA operating quarters) or "annually" (within 4 QA operating quarters), not to exceed 8 calendar quarters between successive tests.

[d] That is, a quarter in which the fuel measured by the flowmeter is combusted for at least 168 hours.

Table 18. Quality Assurance/Quality Control Criteria for Sorbent Trap Monitoring Systems

QA/QC Test or Specification	Acceptance Criteria	Frequency	Consequences if Not Met
Pre-test leak check	≤4% of target sampling rate	Prior to sampling	Sampling shall not commence until the leak check is passed
Post-test leak check	≤4% of average sampling rate	After sampling	Sample invalidated[a]
Ratio of stack gas flow rate to sample flow rate	Maintain within ± 25% of initial ratio from first hour of data collection period	Every hour throughout data collection period	Case-by-case evaluation
Sorbent trap section 2 breakthrough	≤5% of Section 1 Hg mass	Every sample	Sample invalidated[a]
Paired sorbent trap agreement	≤10% Relative Deviation (RD)	Every sample	Sample invalidated[a]
Spike recovery study	Average recovery between 85% and 115% for each of the 3 spike concentration levels	Prior to analyzing field samples and prior to use of new sorbent media	Field samples shall not be analyzed until the percent recovery criteria has been met
Multipoint analyzer calibration	Each analyzer reading within ± 10% of true value <u>and</u> $r^2 \geq 0.99$	On the day of analysis, before analyzing any samples	Recalibrate until successful
Analysis of independent calibration standard	Within ± 10% of true value	Following daily calibration, prior to analyzing field samples	Recalibrate and repeat independent standard analysis until successful
Spike recovery from section 3 of sorbent trap	75-125% of spike amount	Every sample	Sample invalidated[a]
RATA	RA ≤20.0% <u>or</u> Mean difference ≤ 1.0 µg/dscm for low emitters	For initial certification and annually thereafter	Data from the system are invalidated until a RATA is passed
Dry gas meter calibration (At 3 orifice settings initially, and 1 setting thereafter)	Calibration factor (Y) within ± 5% of average value from the initial (3-point) calibration	Prior to initial use and at least quarterly thereafter	Recalibrate the meter at three orifice settings to determine a new value of Y
Temperature sensor calibration	Absolute temperature measured by sensor within ± 1.5% of a reference sensor	Prior to initial use and at least quarterly thereafter	Recalibrate. Sensor may not be used until specification is met.

Table 18 (cont'd)

QA/QC Test or Specification	Acceptance Criteria	Frequency	Consequences if Not Met
Barometer calibration	Absolute pressure measured by instrument within ± 10 mm Hg of reading with a mercury barometer	Prior to initial use and at least quarterly thereafter	Recalibrate. Instrument may not be used until specification is met

[a] And data from the pair of sorbent traps are also invalidated

8.3 Are there any exceptions to these basic QA test requirements ?

Yes. Table 17 indicates that there are some exceptions to the basic QA test requirements and frequencies for year-round reporters. For instance:

- Linearity checks are not required for SO_2 or NO_x monitors with span values of 30 ppm or less;
- For calendar quarters in which the unit operates for less than 168 hours, limited exemptions from linearity checks and limited extensions of RATA deadlines are available;
- RATAs of SO_2 monitors are not required if the unit exclusively combusts "very low sulfur fuel" (as defined in §72.2) or limits combustion of higher-sulfur fuel to ≤ 480 hours per year;
- For calendar quarters in which a particular fuel is combusted for less than 168 hours, limited extensions of fuel flowmeter accuracy test deadlines are available to Appendix D units; and
- For calendar quarters in which the optional fuel flow-to-load ratio test is performed and passed, limited extensions of fuel flowmeter accuracy test deadlines are available to Appendix D units.

The low-span linearity check exemption described in the first bulleted item above and the SO_2 RATA exemption described in the third bulleted item are permanent exemptions, as long as the conditions continue to be met. However, the test extensions and exemptions described in the second, fourth and fifth bulleted items above are conditional and have definite limits, i.e., no more than 3 consecutive linearity check exemptions may be claimed, a RATA deadline may not be extended beyond 8 calendar quarters from the quarter of the last test, and the accuracy test deadline for a fuel flowmeter may not be extended beyond 5 years (20 quarters) from the quarter of the previous test.

EPA also recognizes that circumstances beyond the control of the source owner or operator, such as a forced unit outage, may prevent a linearity check or RATA from being done in the calendar quarter in which it is due. To provide regulatory relief in these instances, Part 75 allows the test to be done in a grace period, immediately following the end of that quarter. For a linearity check, the grace period is 168 unit operating hours, and for a RATA it is 720 unit operating hours. Provided that the missed QA test is performed and passed on the first attempt within the grace period, no loss of emissions data will be incurred by the affected source.

8.4 Are there any special considerations when performing these basic QA tests ?

Yes, there are a number of things must be taken into consideration when performing the QA tests, to ensure that they are done properly:

- Daily calibration error tests, interference checks, and linearity checks must be done while the unit is on-line (i.e., combusting fuel). The only exception to this is that off-line calibration error tests may be used to validate up to 26 consecutive hours of emissions data, if the off-line calibration error demonstration described in section 2.1.5 of Appendix B has been performed and passed.

- All RATAs of gas monitors must be done at normal load, while combusting a fuel that is normal for the unit. For the RATA of an Hg monitoring system, the unit must be burning coal. Normal load is defined in the monitoring plan as the most frequently-used load level (low, mid, or high). To determine the normal load:

    - First, the unit's range of operation is defined. It extends from the "minimum safe, stable load" to the "maximum sustainable load"

.

    - Second, the operating range is divided into three load bands, or levels. The first 30% of the range is defined as low load, the next 30% is mid load, and the remainder of the range is high load.

    - Third, at least four quarters of representative historical load data are analyzed[54], to determine which load levels are used the most frequently. The load level used most frequently must be designated as the normal load. The load level that is used second most frequently may be designated as a second normal load level[55].

- For flow monitors installed on peaking units and bypass stacks, only single-load RATAs are required.

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[54] For new units, projections of the anticipated manner of unit operation may be used to define the normal load level, and then any necessary adjustments can be made based on the actual unit operation

[55] The advantage of designating two normal loads is that gas monitor RATAs may be done at either load level. The "down side" is that for flow RATAs, a bias test must be taken at both normal load levels, which increases the chances that a bias adjustment factor (BAF) will have to be applied to the flow rate data.

- For all other flow monitors:

  - The annual RATAs must be done at the 2 most frequently-used load levels or (at the source's discretion) at all 3 loads, <u>unless</u>

  - The unit has operated at one load level (low, mid or high) for $\geq$ 85% of the time since the last annual flow RATA, in which case a single-load test at normal load may be performed.

  - A 3-load RATA is required at least once every 5 calendar years

- If a semiannual RATA frequency[56] is obtained, an additional RATA must be done in-between the annual RATAs. For a flow monitor, this "extra" RATA may be a single-load test at normal load.

- For units that do not produce electrical or steam load, such as cement kilns, and refinery process heaters, the RATA requirements are basically the same as for load-based units, except that the terms "level" and "operating level" apply instead of the terms "load" and "load level". Also, it is possible, with a proper justification in the monitoring plan[57], for a non load-based unit to be partly or fully exempted from performing multi-level flow RATAs.

- The quarterly "flow-to-load ratio test" is not actually a test at all. Rather it is a data analysis, which, in most cases, is performed automatically by the DAHS. The purpose of the test is to ensure that flow monitors continue to provide accurate data in-between RATAs. The "test" is performed as follows:

  - The hourly ratio of the stack gas flow rate to unit load is calculated for a segment of the quarterly flow rate data (i.e., those hours where the load was within 10% of the average load during the last normal load flow RATA).
  - These hourly ratios are then compared against a "reference" flow-to-load ratio, which is the ratio of the average reference method flow rate to the average unit load from the last normal-load RATA.
  - Alternatively, the data analysis may be done on the basis of the "gross heat

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[56] See section 8.6 of this guide.

[57] If it can be demonstrated to the satisfaction of the permitting authority that the process operates only at one or two distinct points, the requirement to perform 3-level, or perhaps even 2-level flow RATAs may be waived.

rate"[58] (GHR), which is the ratio of heat input rate to unit load), rather than using the flow-to-load ratio.

8.5 What are the on-going QA test requirements for ozone season-only reporters ?

If a unit is in the NO_x Budget Trading Program but is not an Acid Rain Program unit, emissions data may be reported on an ozone season-only basis rather than year-round, if this is allowed by the State regulation. Ozone season-only reporting is also allowed for units that are in the CAIR Ozone Season Trading Program and are not otherwise required to report year-round. If ozone season-only reporting is permitted and this option is selected, the quality assurance procedures under §75.74 (c) in Subpart H of Part 75 must be met. These procedures require some pre-ozone season quality assurance testing between October 1 and April 30, and other QA testing inside the ozone season (May 1st through September 30th).

The QA test requirements for ozone season-only reporting are considerably different from, and quite a bit more complex than, the requirements for year-round reporters. For example:

- The required pre-season linearity check of a gas monitor may be done in April (2nd quarter). However, if the unit operates for $\geq$ 168 hours in May and June, an additional 2nd quarter linearity check is required;

- The "window" of data validation for a RATA extends only for 2 calendar quarters (for semiannual frequency) or 4 calendar quarters (for annual frequency). The "QA operating quarter" concept (see Table 17) may not be used to extend RATA deadlines;

- Daily calibrations must be performed from the date and hour of any pre-ozone season linearity check or RATA , through April 30th;

- If a RATA was performed inside the ozone season, the test may be used to validate data in the next ozone season, but only if these conditions are met:
  - The data validation window from the RATA extends into the next ozone season; and
  - The monitoring system is maintained and operated, and daily calibrations are performed, throughout the entire pre-ozone season period from October 1st of the current year through April 30th of the next year

[58] The gross heat rate approach includes the diluent gas (CO_2 or O_2) concentration in the equation. This alternative is most useful for common stack configurations.

These are but a few of the QA provisions in §75.74(c). For a complete listing, see Table III-A in Appendix III of this guide. In view of this, sources that qualify to use the ozone season-only reporting option should carefully weigh the perceived benefits of this option, such as reduced reporting requirements and less required maintenance of CEMS during the off-season, against the potential invalidation of emissions data (and consequent loss of NO_x allowances) that could result from a misunderstanding or misapplication of the rule requirements.

8.6 What performance specifications must be met for the routine QA tests required by Part 75 ?

The performance specifications for the routine Part 75 QA tests are basically the same as for initial certification (see Table 16 in Section 7 of this guide). There are, however, a few notable exceptions:

- For daily calibration error tests of SO_2, NO_x, CO_2, O_2, and flow monitors, the calibration error (C.E.) specifications are twice as wide as the C.E.'s allowed in the 7-day calibration error test for initial certification. For example, when an SO_2 monitor is certified, the maximum allowable C.E. during the 7-day calibration error test is ± 2.5% of the span value, but the "control limits" for daily operation of the monitor are ± 5.0% of span.

- For SO_2 and NO_x monitors with span values of 50 ppm or less (which are exempted from the 7-day calibration error test), the control limits for daily calibration error tests are either ± 5.0% of span or $|R - A| \leq 5$ ppm.

- For RATAs, there is an incentive system that rewards good monitor performance. RATAs may be performed annually rather than semiannually if a certain level of relative accuracy is achieved[59]. The relative accuracy test frequency incentive system is summarized in Table 19. Table 19 shows that when the percent relative accuracy is 7.5% or less, the test frequency is annual. But even if 7.5% RA is not achieved, the monitoring system may still be eligible for an annual RATA frequency, if an alternative relative accuracy specification is met. The alternative specifications are also shown in Table 19, and they apply to:

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    - Low emitters of SO_2 and NO_x ;
    - Sources with very low stack gas velocities; and
    - Moisture, CO_2 , and O_2 monitoring systems.

  In each case, the alternative RA specification is the difference between the mean values of the reference method and CEMS measurements from the RATA.

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[59] Except for RATAs of Hg CEMS and sorbent trap monitoring systems, which are only required annually

Table 19: Relative Accuracy Test Frequency Incentive System

For a RATA of this type of monitoring system....	The test frequency is annual, rather than semiannual, if the % RA is....	However, if the following conditions are met.....	Then annual frequency may be attained by meeting this alternative RA specification[a].....
SO_2 or NO_x concentration	≤ 7.5%	$(RM)_{avg}$ ≤ 250 ppm[b]	± 12.0 ppm
NO_x -diluent	≤ 7.5%	$(RM)_{avg}$ ≤ 0.200 lb/mmBtu	± 0.015 lb/mmBtu
Flow	≤ 7.5%	$(RM)_{avg}$ ≤ 10.0 ft/sec	± 1.5 ft/sec
CO_2 or O_2	≤ 7.5%	--------------	± 0.7% CO_2 or O_2
Moisture	≤ 7.5%	---------------	± 1.0% H_2O

[a] The alternative RA specification is the difference between the mean CEMS and reference method values from the RATA, i.e., $[(CEMS)_{avg} - (RM)_{avg}]$

[b] $(RM)_{avg}$ is the mean value of the reference method measurements from the RATA

- For the flow-to-load ratio (or gross heat rate) test, which is not required for initial certification, the pass/fail criterion is the absolute average percent deviation of the hourly flow-to-load ratios (or hourly heat rates) from the reference ratio (or reference heat rate). Table 20, below, summarizes the acceptance criteria.

Table 20: Flow-to-Load Ratio or Gross Heat Rate Test Acceptance Criteria

For this QA test.....	If the unit load (or combined load for a common stack) during the last normal-load flow RATA was.....	Then, to pass the test, the absolute average percent deviation from the reference ratio or heat rate must be.....	
Flow-to-load ratio or Gross heat rate	≥60 MW or ≥500 klb/hr of steam	≤15.0% if unadjusted flow rates are used in the calculations	≤10.0% if bias-adjusted flow rates are used in the calculations
Flow-to-load ratio or Gross heat rate	< 60 MW or < 500 klb/hr of steam	≤20.0% if unadjusted flow rates are used in the calculations	≤15.0% if bias-adjusted flow rates are used in the calculations

8.7 Are there any notification requirements for the periodic QA tests ?

Yes. Part 75 requires sources to provide notice to CAMD, to the EPA Regional Office, and to the State, at least 21 days in advance of the following QA tests:

- RATAs
- Appendix E retests
- LME unit retests

Part 75 also allows any of the regulatory agencies to issue a waiver from these notification requirements. CAMD has waived these notification requirements. Therefore, sources are currently required to notify only the State and EPA Region, unless those agencies issue a similar waiver.

8.8 What are the Essential Elements of a Part 75 QA/QC Program ?

Part 75 requires all owners and operators of affected units to develop and implement a quality assurance/quality control (QA/QC) program for the continuous monitoring systems. Each QA/QC program must include a written plan[60] that describes in detail the step-by-step procedures and operations for a number of important activities. This quality assurance plan must be made available to the regulatory agencies upon request during field audits. The following are the essential elements that must be included in a QA plan:

- For all monitoring systems:
  - The routine maintenance procedures for the monitoring system, and a maintenance schedule;
  - The procedures used to implement the Part 75 recordkeeping and reporting requirements;
  - Records of all testing, adjustment, maintenance, repair of the monitoring system (e.g., maintenance logs); and
  - Records of corrective actions taken in response to monitoring system outages.

- For CEMS:
  - A written record of the procedures used for the required QA tests (i.e., daily calibration, linearity checks, RATAs, etc.);
  - The procedures used to adjust the CEMS to ensure accuracy; and

[60] Electronic storage of the QA plan information is allowed by the rule, provided that the information can be made available in hard copy upon request during an inspection or audit.

  - For units with add-on SO_2, NO_x, or Hg emission controls, a list of the parameters that are monitored during monitor outages to verify that the controls are working properly, and the acceptable values and ranges of the parameters.

- For sorbent trap monitoring systems:

  - Procedures for permanently marking or inscribing an identification number on each sorbent trap, for tracking purposes;
  - An explanation of the procedures used for leak checks of the traps when they are placed in or removed from service;
  - Other procedures that are used to ensure system integrity and data quality, including dry gas meter calibrations, verification of moisture removal, ensuring air-tight pump operation;
  - The QA/QC criteria of Part 75, Appendix K;
  - The chain of custody procedures used in the packing, transporting and analysis of the sorbent traps;
  - Documentation that the laboratory performing the analyses of the traps either meets the requirements of ISO 17025, or performs and passes the spike recovery study described in Appendix K at least once a year;
  - The rationale for the minimum acceptable data collection time for the size of sorbent trap selected; and
  - A detailed description of the procedures used for RATAs of the sorbent traps.

- For units using the Appendix D and E methodologies:

  - A written record of the fuel flowmeter accuracy test procedures, including (if applicable) transmitter calibration and visual inspection procedures;
  - A record of all adjustments, maintenance or repairs of the fuel flowmeter monitoring system;
  - A written record of the standard procedures used to perform the periodic fuel sampling and analysis;
  - For Appendix E units, a list of the operating parameters that are continuously monitored, and acceptable ranges for the parameters; and
  - A record of the procedures used to perform the required Appendix E NO_x emission testing.

- For pertinent information concerning the QA/QC requirements for LME units, see Section 6.1.7 of this guide.

9.0 MISSING DATA SUBSTITUTION PROCEDURES

9.1 Does Part 75 require emissions to be reported for *every* unit operating hour ?

Yes. In cap and trade programs, sources are accountable for their emissions during each hour of unit operation, because compliance is assessed by comparing the total mass emissions for the compliance period (i.e., year or ozone season) to the total number of allowances held. Therefore, Part 75 requires a complete data record for each affected unit. Emissions data must be reported for each unit operating hour, without exception.

9.2 How are emissions data reported when a monitoring system is not working ?

In real-life situations, quality-assured emissions data may not be available for some hours, because monitoring equipment occasionally malfunctions or needs to undergo routine maintenance. Also, routine QA tests are sometimes not performed on schedule or are failed. For any unit operating hour in which a monitoring system is unable to provide quality-assured data, the system is considered to be “out-of-control” (OOC). Data recorded by an out-of-control monitoring system are unsuitable for Part 75 reporting and may not be used in the emission calculations. For each hour of an OOC period, emissions data must be provided in one of the following ways:

- Using an approved Part 75 backup monitoring system that is not out-of-control; or
- Using an EPA reference test method; or
- Using an appropriate substitute data value.

Many facilities do not have backup monitoring systems, and even if they do, there is no guarantee that the backup monitor will be in-control during an outage of the primary monitor. Using EPA reference methods to collect data can be expensive and time-consuming. In view of this, there needs to be a standard methodology for determining appropriate substitute data values during missing data periods. The necessary missing data procedures are found in the following sections of Part 75:

- §§75.31 through 75.38, for units that use CEMS and report emissions data on a year-round basis;
- §75.39 for sorbent trap monitoring systems
- §75.74 (c)(7), for NO_x Budget Program units that use CEMS and report emissions data on an ozone season-only basis;
- Section 2.4 of Appendix D;
- Section 2.5 of Appendix E; and
- Section 5 of Appendix G

The Part 75 missing data substitution process is shown in Figure 4.

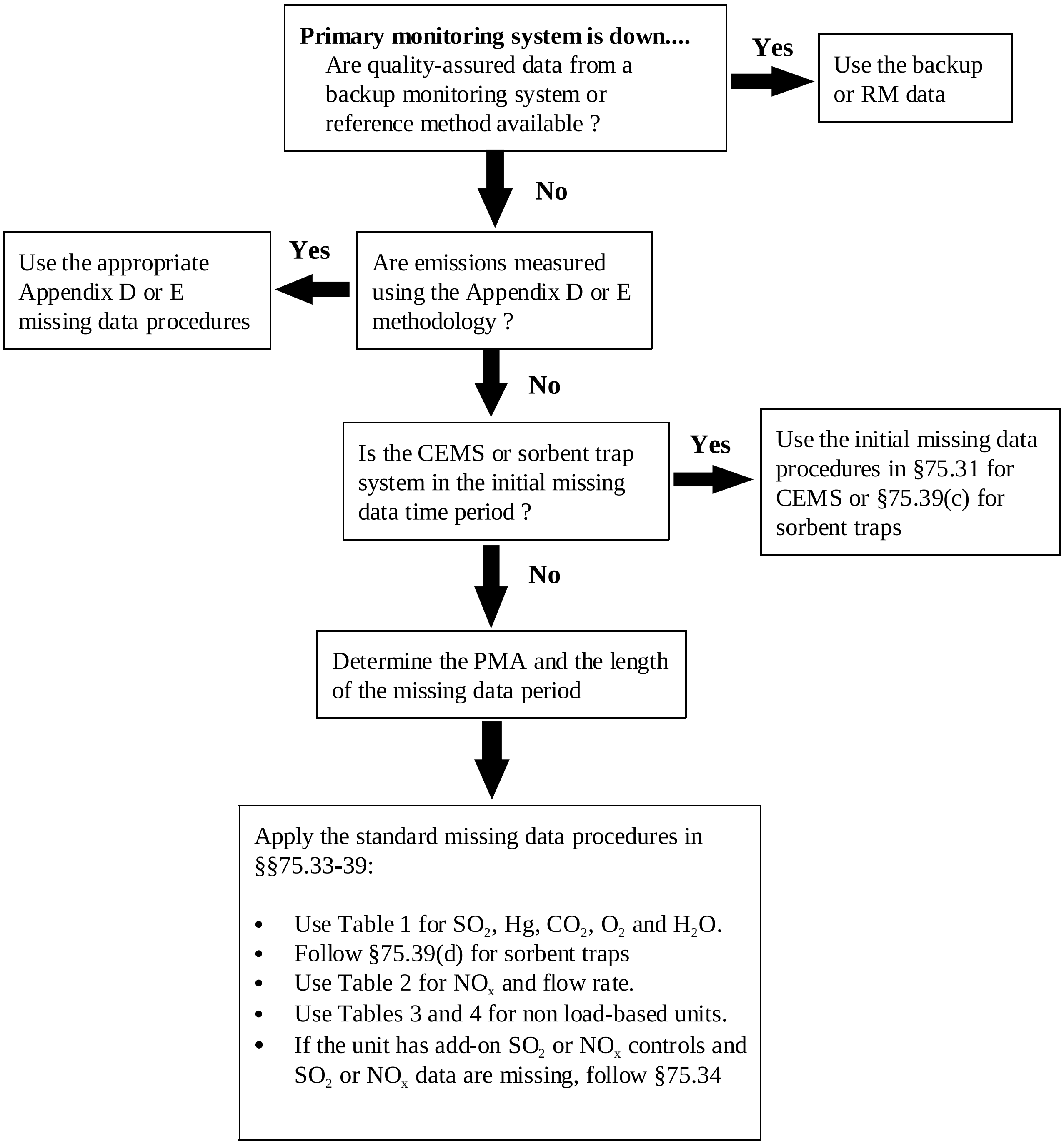

Figure 4. Part 75 missing data substitution process

9.3 What are the Part 75 missing data procedures for CEMS ?

In general, the Part 75 missing data procedures for CEMS are designed to provide conservatively high substitute data values, to ensure that emissions are not underestimated during monitor outages. Application of the missing data procedures begins either at the date and hour of provisional certification, when the CEM systems have passed all required certification tests and begin generating quality-assured data, or when the certification deadline expires, if the monitoring systems have not passed all of the required tests..

Two distinct sets of CEMS missing data algorithms are described in Part 75---the "initial" and the "standard" missing data routines. The initial missing data algorithms in §75.31 are temporary "spin-up" procedures that are used for a specified period of time, after which the standard missing data algorithms in §§75.33 through 75.38 begin to be applied[61]. For both the initial and standard missing data procedures, all of the appropriate substitute data values are calculated and applied automatically by the data acquisition and handling system (DAHS). If a missing data period extends past the end of a quarter, it is treated as two separate missing data periods, one terminating at the end of the quarter and one starting at the beginning of the next quarter.

The initial missing data procedures are used until a certain number of hours of quality-assured CEM data have been obtained. For SO_2, Hg, CO_2, O_2, and moisture, this number is 720 hours, and for NO_x and flow rate, it is 2,160 hours. The initial missing data algorithms are simple and the substitute data values derived from them are likely to be close to the actual values. For example, the algorithm for SO_2 is the arithmetic average of the SO_2 concentrations from the hour before and the hour after the missing data period. For NO_x and flow rate, the substitute data value for each hour is an arithmetic average of the available historical data at similar load levels.

Once the requisite number of hours of quality-assured data has been obtained (i.e., 720 or 2,160), use of the initial missing data procedures ceases and the standard missing data procedures begin to be applied.[62] The standard missing data routines use a tiered approach, that takes into account both the percent monitor data availability[63] (PMA) and the length of the missing data period. When the PMA is high ($\geq$95%) and the missing data period is relatively short ($\leq$ 24 hr), the standard missing data algorithms are nearly identical to the initial missing data routines---consequently, the substitute data values are generally not punitive. However, as the PMA decreases, the substitute data values become increasingly conservative, to ensure that emissions are not under-reported. For

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[61] For sorbent trap monitoring systems, the initial and standard missing data procedures are found in §75.39. The missing data algorithms for sorbent traps are similar, but not identical, to the algorithms used for Hg CEMS. This is due to the fundamental difference in the way that data is collected and recorded with the two types of Hg monitoring systems.

[62] If three years have elapsed since the date of provisional certification and the requisite number of hours of quality-assured data have not yet been obtained, the owner or operator must switch to the standard missing data routines. All available quality-assured data from the previous three years are used for the "lookbacks", until 720 (or 2,160, as applicable) hours of quality-assured data have been accumulated.

[63] In its simplest form, the PMA is the ratio of the number of quality-assured hours to the number of unit operating hours, in a specified lookback period. The PMA is calculated hourly by the DAHS.

example, when the PMA of an SO_2 or NO_x monitoring system is between 80% and 90%, the substitute data value will be the maximum value observed by looking back through the last 720 hours (for SO_2) or 2,160 hours (for NO_x) of historical, quality-assured emission data[64]. But if the PMA drops below 80%, regardless of the length of the missing data period, the maximum potential SO_2 concentration or the maximum potential NO_x emission rate must be reported.

For units with add-on SO_2, NO_x, or Hg emission controls, the use of the initial and standard missing data routines is conditional. The condition is that parametric data must be available to document that the add-on controls are working properly during the missing data period. For any hour in which this parametric evidence is unavailable, the maximum potential concentration or the maximum potential emission rate must be reported.

The initial and standard missing data algorithms for NO_x and stack gas flow rate are load-based, in order to provide more representative substitute data values. Appendix C of Part 75 requires the owner or operator to establish 10 load ranges or "load bins", by dividing the operating range of the source (e.g., 0 to 500 megawatts) into 10 equal parts[65]. Then, during periods of missing NO_x or flow rate data, the substitute data value for each hour is calculated using historical quality-assured data in the corresponding load bin.

However, certain units in the NO_x Budget Program, such as cement kilns and refinery process heaters, do not produce electrical or steam load. To accommodate these sources, EPA added a series of special missing data algorithms for NO_x and flow rate to Part 75 in 2002. The algorithms are structurally similar to the standard NO_x and flow rate missing data routines, except that they are not load-based. To alleviate industry concerns that the substitute data values determined in this manner may not be representative, the rule allows the affected sources to define "operational bins" corresponding to different process operating conditions, and to populate each bin with CEM data. The substitute data value for each missing data hour is then drawn from the appropriate operational bin.

As part of the 2002 revisions to Part 75, EPA also added provisions to §§75.33 and 75.34. These new provisions allow sources to implement the standard missing data routines in a slightly different manner, in order to obtain more representative substitute data values. Affected sources that burn different types of fuel now have the option to separate their historical CEM data according to fuel type and to apply the standard missing data procedures on a fuel-specific basis. Also, for a unit that is subject to the NO_x Budget Program or to the CAIR Ozone Season Trading Program, <u>and</u> is equipped with add-on NO_x controls, <u>and</u> reports emissions data year-round, the owner or operator may separate the NO_x emission data into ozone season and non-ozone season data "pools". Then, depending on the time of the year that the missing data period occurs (i.e., inside or outside the ozone season), the substitute data values are drawn from the appropriate data pool. This missing data option is advantageous when the NO_x emission controls are operated only (or principally) during the ozone season.

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[64] For sources that report NO_x mass emissions data on an ozone season-only basis, only data from inside the ozone season are included in the missing data lookbacks.

[65] Alternatively, at a common stack, 20 load bins may be defined for flow rate.

9.4 What are the missing data procedures for Appendices D, E and G ?

Appendix D

Appendix D of Part 75 includes missing data procedures for fuel flow rate, fuel sulfur content, GCV and density. The Appendix D missing data algorithms are considerably less complex than the CEMS missing data routines. The standard Appendix D missing data algorithms for fuel flow rate are the most sophisticated, in that they are fuel-specific and load-based. However, the substitute data value for each hour is simply an arithmetic average of the data in the corresponding load bin, based on a lookback through 720 hours of quality-assured data[66].

Appendix D requires missing data substitution for fuel sulfur content, GCV and density whenever a required periodic sample for any of these parameters is not taken, or when the results of a sample analysis are missing or invalid. The missing data approach is quite simple, in that the maximum potential value of the parameter is reported for each hour of the missing data period. Fuel-specific maximum potential values for sulfur content, GCV and density are defined in Table D-6 of Appendix D. In some cases, a conservatively high default value is prescribed (e.g., 1.0% sulfur for diesel fuel). In other cases, a multiplier is applied to the highest value in a lookback through recent fuel sampling results (e.g., 1.5 times the highest sulfur content from the previous 30 daily gas samples).

Appendix E

For Appendix E units, missing data substitution is required for any unit operating hour in which:

- One or more of the monitored QA/QC parameters is either unavailable or outside the acceptable range of values; or
- The measured heat input rate is higher than the highest heat input rate from the baseline correlation tests; or
- For a unit with add-on NO_x emission controls, the controls are either shut off or cannot be documented to be working properly; or
- Emergency fuel is combusted, unless a separate correlation curve has been derived for the fuel.

Appendix E missing data substitution is fairly straightforward. When the QA/QC parameters are unavailable or outside the acceptable range of values, the substitute data value is simply the highest NO_x emission rate from the baseline correlation curve. When the measured heat input rate is above the highest value from the baseline testing, there are two missing data options for NO_x emission rate. Either:

- Report the higher of the linear extrapolation of the correlation curve or the maximum potential NO_x emission rate (MER); or

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[66] Note that for peaking units, Appendix D allows a simplified missing data procedure to be used for fuel flow rate. Iinstead of using the standard lookback procedures, the maximum potential fuel flow rate may be reported for each hour of the missing data period.

- Report 1.25 times the highest value on the correlation curve, not to exceed the MER.

The fuel-specific MER must be reported for units with add-on NO_x emission controls, whenever the controls are either shut off or cannot be documented to be working properly. The MER must also be reported when emergency fuel is combusted, if there is no baseline correlation curve for that fuel.

Appendix G

For Acid Rain Program units using Appendix G to determine CO_2 mass emissions, missing data substitution is required whenever the results of the required fuel sampling and analysis for carbon content or GCV are missing or invalid. For periods of missing carbon content, either the appropriate default value from Table G-1 in Appendix G or the results of the most recent valid sample may be reported. When the GCV is missing, Table D-6 in Appendix D is used to determine the substitute data value.

9.5 What is conditional data validation?

When a significant change is made to a CEMS (e.g., replacement of an analyzer) and the system must be recertified, the CEMS must pass a series of recertification tests before it can be used to report quality-assured data. In most cases, recertification takes at least 7 days (since a 7-day calibration error test is usually one of the required tests). However, while the recertification tests are in progress, the requirement to report emissions data for every unit operating hour remains in effect. Without regulatory relief, this could result in an extended period of missing data substitution, and possible loss of allowance credits.

To alleviate this situation, §75.20(b)(3) of Part 75 allows conditional data validation (CDV) to be used for recertification events. Conditional data validation provides a means of minimizing the use of substitute data while a CEMS is being tested for recertification. To take advantage of this rule provision, as soon as the monitoring system is ready to be tested, a calibration error test is performed. This is called a "probationary calibration". If the probationary calibration is passed, data from the CEMS are assigned a conditionally valid status from that point on, pending the results of the recertification tests.

If the required recertification tests are then performed and passed within a certain time frame[67], with no test failures, all of the conditionally valid data recorded by the CEMS from the date and hour of the probationary calibration to the date and hour of completion of the required tests may be reported as quality-assured. However, if one of the major recertification tests (such as a linearity check or RATA) is failed, then all of the conditionally valid data are invalidated and missing data substitution must be used until all of the required tests have been successfully completed.

Part 75 extends the use of conditional data validation beyond recertification events. The procedures may also be used for initial certification, diagnostic testing, and for routine QA testing. The application of conditional data validation to initial CEMS certification is particularly

[67] According to §75.20(b)(3)(iv), linearity checks and cycle time tests must be completed within 168 unit operating hours after the probationary calibration error test. For a RATA, 720 operating hours are allowed, and a 7-day calibration error test must be completed within 21 unit operating days.

advantageous for new sources in the NO_x Budget Program, which are accountable to report NO_x mass emissions from the hour of unit start up (i.e., "first-fire"). The use of CDV for these new sources allows a significant amount of the data recorded prior to completion of the certification tests to be reclaimed and reported as quality-assured— data which otherwise would be invalidated and reported as maximum potential values. Note that if CDV is used for initial certification, it may be used for the entire window of time allotted for certification (up to 180 days in some cases), and the shorter time frames described in §75.20(b)(3)(iv) do not apply[80]. Conditional data validation is also useful when:

- Monitor repair or maintenance activities are performed that trigger diagnostic test requirements; or
- A routine QA test, such as a linearity check or RATA is failed or aborted due to a problem with the monitoring system and must be repeated.

In these instances, a probationary calibration may be done following corrective actions, and the CDV procedures applied until the required diagnostic test or QA test has been performed.

10.0 PART 75 REPORTING REQUIREMENTS

10.1 What are the basic reporting requirements of Part 75 ?

Under the Acid Rain and NO_x Budget Programs, electronic and hard copy data of various kinds (e.g., emissions data, monitoring plan information, results of certification and QA tests. etc.) must be reported to EPA and to the State at certain times, as specified in Part 75.

Initial Reporting

The initial Part 75 reporting requirements include the submittal of a monitoring plan and the results of the monitoring system certification tests. These requirements have been previously discussed in Section 7 of this guide.

Quarterly Reporting

In general, emissions data must be reported electronically each quarter, beginning either at the date and hour of provisional certification when all certification tests have been completed or the date and hour of the certification deadline specified in the rule, whichever comes first[68]. EPA uses the quarterly report data to assess compliance, by comparing each unit's reported annual SO_2 mass emissions and/or ozone season NO_x mass emissions against the number of allowances held. For coal-fired units with annual NO_x emission limits under 40 CFR Part 76, the Agency also assesses compliance with these limits.

Quarterly reporting of hourly emissions data is vital to the success of a cap and trade program. Quarterly reporting eases the administrative burden associated with the data reconciliation and allowance accounting process, because it enables EPA and the affected sources to work together during the year or ozone season to address any problems with the data, rather than waiting until the year or ozone season is over.

All quarterly reports must be submitted to EPA by direct computer-to-computer transfer, either by E-mail or by using an EPA-provided software tool known as the Emissions Tracking System File Transfer Protocol, or "ETS-FTP". The reports are due within 30 days after the end of each calendar quarter. During this 30-day submission period, the reports may be revised and resubmitted as many times as necessary.

The data in each quarterly report must be in a standardized electronic data reporting (EDR) format provided by EPA[69]. The data acquisition and handling system (DAHS) must be capable of recording all of the necessary data and putting it into this format. Currently, there are two versions of the EDR, i.e., versions 2.1 and 2.2. Most affected units use version 2.1 and have the option to upgrade to version 2.2. However, version 2.2 is required for non load-based units, LME units, and

[68] There is an exception to this, for new units in the NO_x Budget Program, which must report emissions data from first-fire.

[69] The version 2.1 and 2.2 EDR formats and accompanying Instructions are found on the Clean Air Markets Division website, at: http://www.epa.gov/airmarkets/reporting/edr21/index.html

for units using certain Part 75 compliance and missing data options.

The quarterly EDR files must include the following essential information:

- Facility information;
- Hourly and cumulative emissions data;
- Hourly unit operating information (e.g., load, heat input rate, operating time, etc.);
- Monitoring plan information;
- Results of required quality-assurance tests (e.g., daily calibrations, linearity checks, RATAs, etc.); and
- Certification statements from the Designated Representative or Authorized Account Representative (or the Alternate Representative), attesting to the completeness and accuracy of the data.

The data from each quarterly report submittal are recorded and stored in EPA's Emissions Tracking System (ETS). The tracking system consists of the previously-mentioned ETS-FTP software and data checking routines, housed in an EPA mainframe computer. All sources must obtain an account and a password from EPA in order to submit their EDR files. The success of the cap and trade programs depends vitally on ETS. It instils confidence in allowance transactions by certifying the existence and quantity of the commodity being traded.

EPA recommends that sources pre-screen their EDR data before making an official submittal. ETS has a test region where quarterly reports can be sent to receive a preliminary feedback report. Also, EPA has developed the Monitoring Data Checking (MDC) software, which is available to all via the Internet[70]. EPA uses MDC to perform routine electronic audits of the quarterly reports (see Sections 10.2 and 10.3, and Figure 5, below).

10.2 How does EPA evaluate the electronic quarterly reports ?

Each quarter, EPA reviews and evaluates the EDR reports, using the following four-step review process:

- **Data Review -** The quarterly reports are analyzed using two software tools: ETS and MDC. The ETS software recalculates the reported emissions from the raw data. MDC checks the monitoring plan information, recalculates the reported QA test results, and determines whether the source is up-to-date on its important QA tests, such as linearity checks, RATAs, etc. The ETS and MDC evaluations identify sources with reporting problems and also flag sources that have not submitted their EDRs by the reporting deadline.
- **Feedback to Sources -** EPA provides feedback to the sources, based on the results of the

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[70] The MDC software and information on how to use it can be found at the following website address: http//www.epa.gov/airmarkets/monitoring/mdc/index/html

ETS and MDC evaluations. The feedback reports indicate that either:

- The data have been accepted and will be stored in the EPA mainframe for the purposes of annual reconciliation and dissemination; or
- The EDR is unacceptable, and contains "critical" errors that prevent the data from being used for allowance accounting and dissemination; or
- The data have been accepted, but EPA has identified "non-critical" (informational) errors that must be corrected in subsequent quarterly reports.

- **Data Resubmission** - EPA requires reports with critical errors to be resubmitted by a specified deadline (generally within 30 days).
- **Data Dissemination** - All data are reviewed, and preliminary and final emissions data reports are prepared for public release and compliance determination.

10.3 Part 75 Audit Program

When emissions data are reported in a standardized electronic format such as the EDR, regulatory agencies can develop software tools with which to audit the data. The results of these electronic audits can serve as a basis for targeting problem sources, either for more comprehensive electronic audits or for field audits. In the Part 75 audit program, both electronic audits and field audits are routinely performed.

Special Electronic Audits

In addition to the routine electronic audits of the Part 75 electronic quarterly reports, using the ETS and MDC software tools. EPA also occasionally performs special (ad-hoc) electronic audits to look for other specific data reporting problems (e.g., incorrect application of the missing data routines).

Field Audit Targeting Tool

EPA has recently developed an electronic auditing software tool, known as the Targeting Tool for Field Audits (TTFA). This tool is intended to be used primarily by State agencies, to assist them in targeting sources for field audits. The TTFA tool is capable of identifying a variety of CEMS operation and maintenance problems, such as monitoring systems with an excessive number of failed calibration error tests or linearity checks, sources with long periods of monitor down time, monitoring systems with improperly-set span and range values, etc.

Field Audits and Inspections

EPA relies primarily on State and local agencies to conduct field audits of Part 75-affected sources. In many instances, the field audits are integrated with routine source inspections. The audits encourage good monitoring practices by raising plant awareness of Part 75 requirements. Field audits generally include the following activities:

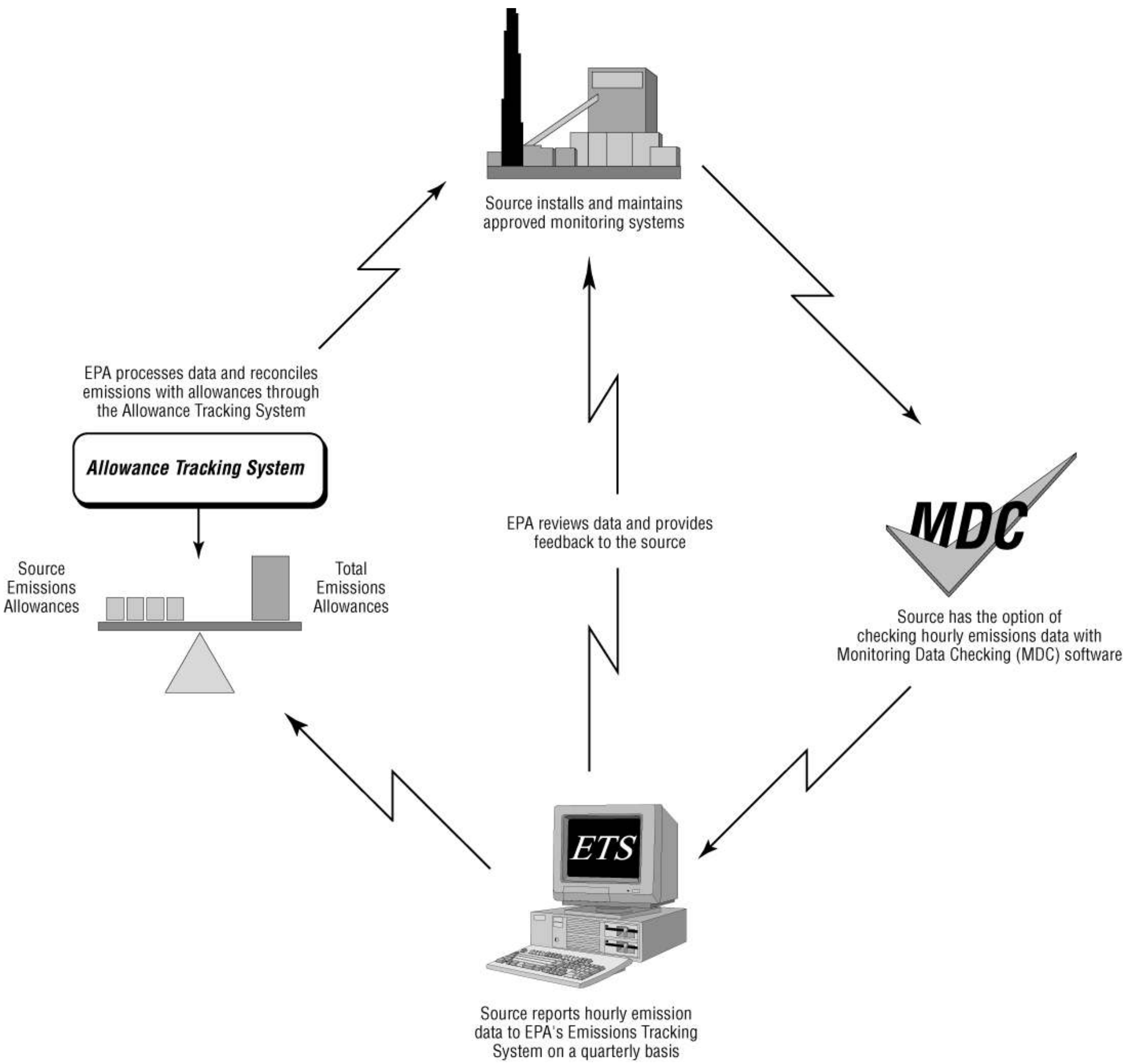

Figure 5. Part 75 data reporting and review process.

- Pre-audit preparation (e.g., monitoring plan review, examination of historical EDR data using MDC or the TTFA targeting tool, etc.);
- On-site inspection of the monitoring equipment and system peripherals;
- Records review;
- QA test observations; and
- Interviews with the appropriate plant personnel.

EPA has developed a Field Audit Manual, which is available on the Internet[71]. The Field Audit Manual details recommended procedures for conducting field audits of Part 75 CEMS. The Manual includes tools that can be used to prepare for an audit, techniques that can be used to conduct the on-site inspections and records review, proper methods for observing QA tests, and guidelines for preparing a final report. Checklists are also provided that can be used to ensure that all necessary data is obtained during the audit. EPA has designed the audit procedures in the Manual so that personnel with varying levels of experience can use them. Three levels of audits are described in the Manual:

- A Level 1 audit, consisting of on-site inspection of the CEM equipment, records review, and observation of a daily calibration error test;
- A Level 2 audit, including all of the Level 1 activities, plus observation of a linearity check or RATA; and
- A Level 3 audit, including the Level 1 activities, plus a performance test (linearity check or RATA) conducted by agency personnel.

Any State or local agency can perform a Level 1 or Level 2 audit, but not all agencies have the necessary equipment or expertise to conduct the performance test required by the Level 3 audit.

10.4 Electronic Reporting—Update

The Clean Air Markets Division of EPA has recently initiated an effort to re-engineer its data collection and processing systems. The goal of this project is to modernize the way in which the Part 75 electronic data is reported to the Agency. The current “record type-column” EDR format will be replaced with an “XML” format that interacts more efficiently with a database structure than does the current format. Proponents of XML believe that using this format will streamline Part 75 reporting and will make the emissions data more accessible to interested parties because of the enhanced database management capabilities.

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[71] The Field Audit Manual is found at the following Internet address: http://www.epa.gov/airmarkets/monitoring/auditmanual/index.html

The DAHS vendors will need to develop the necessary software to generate the electronic reports in XML format. EPA plans to make a gradual transition from the current EDR reporting format to XML reporting. The Agency plans for a “beta test” version of XML to be available by the end of 2006. In 2007, beta testers may opt to use the XML version for some or all of their official quarterly report submittals. In 2008, all sources will, at their discretion, be allowed to report either in the current EDR format or in XML. In 2009, all sources will be required to report only in the XML format.

Some changes to Part 75 will be needed to close out the old EDR format and to support the new XML reporting format. EPA plans to propose these rule changes in November, 2005 and to finalize them by the end of 2006.

APPENDIX I

Regulatory Update
(CAIR and CAMR Rules)

APPENDIX I: Regulatory Update (CAIR and CAMR Rules)

On March 10, 2005 and March 15, 2005, respectively, the EPA Administrator signed two important air regulations:

- The Clean Air Interstate Rule (CAIR); and
- The Clean Air Mercury Rule (CAMR)

The CAIR rule, which was published on May 12, 2005, applies to units that produce electricity for sale and serve a generator with a nameplate capacity > 25 megawatts. Some 28 States are affected by the regulation, mostly in the eastern half of the United States. The CAIR rule, which has been codified in 40 CFR Part 96, is a model regulation for a cap and trade program for SO_2 and NO_x. The goal of this program, which will begin in 2008, is to achieve significant reductions in SO_2 and NO_x mass emissions, far exceeding the reductions that have thus far been achieved by the Acid Rain and NO_x Budget Programs.

The CAIR rule actually consists of three separate regulations, i.e., one for annual SO_2 mass emissions, one for annual NO_x mass emissions, and one for ozone season NO_x mass emissions. Most of the affected States are subject to all three of these rules, although a few States (MN, GA, TX) are exempted from the ozone season NO_x rule and a handful of other States (AR, DE, NJ, CT, MA) are subject only to the ozone season NO_x rule. Each affected State is required to submit a SIP revision to EPA for approval within 18 months of the effective date of the rule. If a State adopts the model rule (or something close to it) and submits it as a SIP revision, Agency approval will be automatic.

The CAMR rule, which was published on May 18, 2005, applies to coal-fired units that produce electricity for sale and serve a generator with a nameplate capacity > 25 megawatts. This regulation, which is found at Subpart HHHH of 40 CFR Part 60, is also a model rule for a cap and trade program. The program is designed to achieve substantial reductions in mercury mass emissions, and is scheduled to begin in 2009. The CAMR rule is similar to CAIR, in that each State must submit a SIP revision to EPA within 18 months of the effective date of the rule, and any State SIP revision that adopts the model rule will be automatically approved. However, unlike CAIR, which focuses mainly on the eastern U.S., the CAMR rule is national in its scope and affects all 50 States.

The CAMR regulation is rather unique, in that it is based on section 111(d) of the Clean Air Act. In order to justify a section 111(d) rulemaking for a particular category of existing sources and for a particular pollutant, there must be a New Source Performance Standards (NSPS) regulation in place for the same source category and pollutant. However, prior to 2005, there was no NSPS regulation in existence for mercury emissions from coal-fired power plants. Therefore, on May 18, 2005, a mercury NSPS rule (which had been proposed on January 30, 2004) was published along with the CAMR regulation. The mercury NSPS rule provisions have been codified as amendments to Subpart Da of 40 CFR Part 60. The mercury NSPS applies to coal-fired electric generating units that have a heat input capacity $\geq$ 250 mmBtu/hr and that commence construction after January 1,

2004. The rule requires mercury emissions to be continuously monitored.

Both the CAIR and CAMR rules build upon the existing Part 75 infrastructure and require the emission monitoring and reporting provisions of Part 75 to be implemented. For SO_2 and NO_x, the transition to CAIR should be relatively smooth, because Part 75 monitoring and reporting of SO_2 and NO_x mass emissions has been successfully implemented under the Acid Rain and NO_x Budget Programs for many years. Most of the units affected by CAIR are currently in one or the other (or both) of these Programs and already have some or all of the required Part 75 monitoring systems in place.

However, implementation of the mercury trading program under the CAMR rule will be more challenging, because continuous mercury monitoring has not been required by any State or Federal regulation prior to the CAMR rule. In view of this, as part of the May 18, 2005 final rule package, EPA has added Subpart I to Part 75. Subpart I serves the same purpose for mercury mass emissions monitoring as Subpart H of Part 75 does for NO_x mass emissions monitoring, in that it provides the monitoring guidelines for a multi-state trading program. The May 18, 2005 final rule has also added specific mercury monitoring provisions to Part 75, in support of Subpart I. These new mercury monitoring provisions apply only to units that are regulated under a State or Federal mercury mass emissions reduction program that adopts Subpart I.

EPA is aware that mercury monitoring technology is still in its infancy and is not nearly as well-understood or as well-established as SO_2 and NO_x monitoring technology. However, the results of recent field studies of mercury monitors have been encouraging, and at the present rate of progress, mercury monitoring technology is expected to be sufficiently developed by the time the CAMR rule is implemented.

APPENDIX II

Part 75 Monitoring Requirements for Common Stack and Multiple Stack Configurations

The following Table summarizes the Part 75 monitoring requirements for common stack and multiple stack configurations, under the Acid Rain, NO_x Budget, CAIR and CAMR trading programs.

Table II-A: Part 75 Monitoring Requirements for Common Stack and Multiple Stack Configurations

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
1	Is in the Acid Rain Program and shares a common stack with other affected units in the Program, but no non-affected units	SO_2 (or CO_2) mass emissions [lb/hr (or tons/hr)]	An SO_2 (or CO_2) monitor and a flow monitor on the duct leading from each unit to the common stack; <u>or</u> An SO_2 (or CO_2) monitor and a flow monitor on the common stack and report the combined emissions
		NO_x emission rate (lb/mmBtu)	A NO_x-diluent monitoring system on each duct leading from each unit to the common stack; <u>or</u> A NO_x-diluent monitoring system on the common stack, subject to certain conditions[1]
		Heat input rate (mmBtu/hr)	A flow monitor and a diluent gas monitor on the duct leading from each unit to the common stack; <u>or</u> A flow monitor and a diluent gas monitor on the common stack and apportion the common stack heat input rate to the individual units on the basis of unit load (i.e., electrical or steam load)
		Opacity (%)	An opacity monitor on each unit, if required to do so by another State or Federal regulation; <u>otherwise</u> An an opacity monitor on the common stack.

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
2	Is in the Acid Rain Program and shares a common stack with at least one other unit that is not in the Acid Rain Program	SO_2 (or CO_2) mass emissions [lb/hr (or tons/hr)]	An SO_2 (or CO_2) monitor and a flow monitor on the duct leading from each affected unit to the common stack; or An SO_2 (or CO_2) monitor and a flow monitor on the common stack, subject to certain conditions[2]
		NO_x emission rate (lb/mmBtu)	A NO_x-diluent monitoring system on the duct leading from each affected unit to the common stack; or A NO_x-diluent monitoring system on the common stack and petition the Administrator under §75.66 for approval of a strategy to apportion the common stack emission rate to the individual units
		Heat input rate (mmBtu/hr)	A flow monitor and a diluent gas monitor on the duct leading from each affected unit to the common stack; or A flow monitor and a diluent gas monitor on the common stack, subject to certain conditions[3]
		Opacity (%)	An opacity monitor on each unit, if required to do so by another State or Federal regulation; otherwise An opacity monitor on the common stack.

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
3	Is in the Acid Rain Program and either: (a) Has multiple exhaust stacks <u>or</u> (b) Has multiple breechings (i.e., ducts) leading to a single stack, and the owner or operator elects to monitor in the breechings	SO_2 (or CO_2) mass emissions [lb/hr (or tons/hr)]	An SO_2 (or CO_2) monitor and a flow monitor on each stack or duct and sum the measured mass emissions.
		NO_x emission rate (lb/mmBtu)	A NO_x-diluent monitoring system and a flow monitor on each stack or duct and determine a Btu-weighted NO_x emission rate for the unit; <u>or</u> If Appendix D is used to measure the unit heat input, install a NO_x-diluent monitoring system on each stack or duct and report the highest hourly NO_x emission rate recorded by any of these systems as the emission rate for the unit; <u>or</u> If the combustion products are well-mixed, install a NO_x-diluent monitoring system on one stack or duct[4]
		Heat input rate (mmBtu/hr)	A flow monitor and a diluent gas monitor on each stack or duct and sum the measured heat input rates for the unit; <u>or</u> If the unit uses Appendix D methodology, use the measured hourly fuel flow rates and the fuel GCV to quantify the unit heat input rate

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
4	Is in the Acid Rain Program and has a main stack-bypass stack exhaust configuration	SO_2 (or CO_2) mass emissions [lb/hr (or tons/hr)]	An SO_2 (or CO_2) monitor and a flow monitor on both the main stack and the bypass stack; or An SO_2 (or CO_2) monitor and a flow monitor only on the main stack and during bypass hours, report the maximum potential SO_2 concentration[5] and the appropriate substitute data values for flow rate and CO_2
		NO_x emission rate (lb/mmBtu)	A NO_x-diluent monitoring system only on the main stack and report the maximum potential NO_x emission rate (MER) during bypass hours; or Follow the procedures for multiple stacks (Case 3(a), above)
		Heat input rate (mmBtu/hr)	A flow monitor and a diluent gas monitor on both the main stack and the bypass stack; or A flow monitor and a diluent gas monitor only on the main stack and report the appropriate substitute data values for flow rate and diluent gas concentration during bypass hours
		Opacity (%)	An opacity monitor on both the main stack and bypass stack; or An opacity monitor only on the main stack, subject to certain conditions[6]

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
5	Is in the NO_x Budget Trading Program or the CAIR NO_x Trading Program(s) and shares a common stack with other affected units in the Program(s), but no non-affected units	NO_x mass emissions (lb/hr)	A NO_x-diluent monitoring system and a flow monitor on the duct leading from each unit to the common stack[7]; or A NO_x concentration monitoring system and a flow monitor on the duct leading from each unit to the common stack[8]; or A NO_x-diluent monitoring system and a flow monitor on the common stack[7] and report the combined NO_x mass emissions; or A NO_x concentration monitoring system and a flow monitor on the common stack[8] and report the combined NO_x mass emissions
		Heat input rate[9] (mmBtu/hr)	A flow monitor and a diluent gas monitor on the duct leading from each unit to the common stack; or A flow monitor and a diluent gas monitor on the common stack and apportion the common stack heat input rate to the individual units by load[10]; or If any unit is oil-or gas-fired, Appendix D methodology (i.e., measured fuel flow rates and fuel GCV) may be used to determine its unit heat input rate. If this option is selected, a flow monitor and diluent monitor must be installed in the duct leading to the common stack for the remaining units.

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
6	Is in the NO_x Budget Trading Program or the CAIR NO_x Trading Program(s) and shares a common stack with at least one non-affected unit	NO_x mass emissions (lb/hr)	A NO_x-diluent monitoring system and a flow monitor[7] on the duct leading from each affected unit to the common stack. Alternatively, if any of the affected units is oil- or gas-fired, for that unit an Appendix D fuel flowmeter may be installed in lieu of the stack flow monitor; or A NO_x concentration monitoring system and a flow monitor[8] on the duct leading from each affected unit to the common stack; or A NO_x-diluent monitoring system and a flow monitor on the common stack, subject to certain conditions[11].
		Heat input rate[9] (mmBtu/hr)	Consistent with the NO_x mass emissions monitoring option used[12], install all necessary flow and diluent gas monitors on the common stack and/or on the ducts leading from the units to the common stack. Alternatively, if any unit is oil-or gas-fired, Appendix D may be used to determine the heat input rate for that unit.

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
7	Is in the NO_x Budget Trading Program or the CAIR NO_x Trading Program(s) and has a main stack and bypass stack exhaust configuration	NO_x mass emissions (lb/hr)	A NO_x-diluent monitoring system and a flow monitor on each stack[7]. Alternatively, if the unit is oil- or gas-fired, Appendix D fuel flowmeters may be used in lieu of installing a stack flow monitor; or A NO_x concentration monitoring system and a flow monitor on each stack[8]; or A NO_x-diluent monitoring system and a flow monitor or a NO_x concentration monitoring system and a flow monitor only on the main stack, and report maximum potential values for NO_x and flow rate when the bypass stack is used.
		Heat input rate[9] (mmBtu/hr)	If both stacks are monitored, install flow and diluent gas monitors on each stack; or If only the main stack is monitored, install flow and diluent gas monitors on the main stack and during bypass hours, use maximum potential flow rate, maximum potential CO_2 (or minimum potential O_2) concentration values in the heat input rate equation; or If the unit is oil or gas-fired, use Appendix D to determine the unit heat input rate.

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
8	Is in the NO_x Budget Program or the CAIR NO_x Trading Program(s) and either: (a) Has multiple exhaust stacks or (b) Has multiple breechings (i.e., ducts) leading to a single stack, and the owner or operator elects to monitor in the ducts	NO_x mass emissions (lb/hr)	A NO_x-diluent monitoring system and a flow monitor on each stack or duct[7] and sum the measured NO_x mass emissions; or A NO_x concentration monitoring system and a flow monitor on each stack or duct[8] and sum the measured NO_x mass emissions; or If the unit is oil- or gas-fired, install a NO_x-diluent system on only one stack or duct, subject to certain conditions[13].
		Heat input rate[9] (mmBtu/hr)	A flow monitor and diluent gas monitor on each stack or duct and sum the measured heat input rates; or If the unit is oil- or gas-fired and meets certain criteria[13], use Appendix D to determine the unit heat input rate.
9	Is in the CAIR SO_2 Trading Program and shares a common stack with other affected units in the Program, but no non-affected units	SO_2 mass emissions (lb/hr)	Follow the guidelines for SO_2 mass emissions in Case 1, above
		Heat input rate (mmBtu/hr)	Follow the guidelines in Case 1, above
10	Is in the CAIR SO_2 Trading Program and shares a common stack with at least one other unit that is not in the Program	SO_2 mass emissions (lb/hr)	Follow the guidelines for SO_2 mass emissions in Case 2, above
		Heat input rate (mmBtu/hr)	Follow the guidelines in Case 2, above

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
11	Is in the CAIR SO_2 Trading Program and either: (a) Has multiple exhaust stacks or (b) Has multiple breechings (i.e., ducts) leading to a single stack, and the owner or operator elects to monitor in the ducts	SO_2 mass emissions (lb/hr)	Follow the guidelines for SO_2 mass emissions in Case 3, above
		Heat input rate (mmBtu/hr)	Follow the guidelines in Case 3, above
12	Is in the Hg Budget Trading Program under CAMR and shares a common stack with other affected units in the Program, but no non-affected units	Hg mass emissions (oz/hr)	A Hg concentration monitoring system or sorbent trap system and a flow monitor on the duct leading from each unit to the common stack .If the units qualify for the low mass emissions option under §75.81(b), the Hg monitoring systems are not required; or A Hg concentration monitoring system or a sorbent trap system and a flow monitor on the common stack and report the combined Hg mass emissions. If the units qualify for the low mass emissions option under §75.81(b), the Hg monitoring system is not required.
		Heat input rate[9] (mmBtu/hr)	A flow monitor and a diluent gas monitor on the duct leading from each unit to the common stack; or A flow monitor and a diluent gas monitor on the common stack and apportion the common stack heat input rate to the individual units by load, according to §75.16(e)[10].

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
13	Is in the Hg Budget Trading Program under CAMR and shares a common stack with at least one non-affected unit	Hg mass emissions[15] (oz/hr)	A Hg concentration monitoring system or sorbent trap system and a flow monitor on the duct leading from each affected unit to the common stack. If an affected unit qualifies for the low mass emissions option under §75.81(b), the Hg monitoring system is not required; or A Hg concentration monitoring system or a sorbent trap system and a flow monitor on the common stack, subject to certain conditions[14]
14	Is in the Hg Budget Trading Program under CAMR and has a main stack and bypass stack exhaust configuration	Hg mass emissions[15] (oz/hr)	A Hg concentration monitoring system or sorbent trap system and a flow monitor on both the main and bypass stacks and sum the Hg mass emissions measured at the two stacks; or A Hg concentration monitoring system or sorbent trap system and a flow monitor on the main stack, use reference methods at the bypass stack, and sum the Hg mass emissions measured at the two stacks; or A Hg concentration monitoring system or sorbent trap system and a flow monitor only on the main stack, and report the maximum potential Hg concentration and substitute data values for flow rate, diluent gas and moisture during bypass hours. If the unit qualifies for the low mass emissions option under §75.81(b), the Hg monitoring system on the main stack is not required.

Case No.	If a unit . . .	Then for this parameter . . .	Install the following monitoring equipment** at these locations . . .
15	Is in the Hg Budget Trading Program under CAMR and either: (a) Has multiple exhaust stacks <u>or</u> (b) Has multiple breechings (i.e., ducts) leading to a single stack, and the owner or operator elects to monitor in the ducts	Hg mass emissions[15] (oz/hr)	A Hg concentration monitoring system or sorbent trap system and a flow monitor on each stack or duct, and sum the Hg mass emissions measured at the stacks (or ducts). If the unit qualifies for the low mass emissions option under §75.81(b), the Hg monitoring systems are not required

Notes----Table II-A

** Although not shown in Cases 1 through 15 in Table II-A, in some instances, installation of a continuous moisture monitoring system will also be required. As described in Table 7 in Section 3.4 of this guide, a correction for stack gas moisture is sometimes required to accurately determine the emissions or heat input rate. When a correction for moisture is needed, the owner or operator must either use an approved default moisture value or install a continuous moisture monitoring system.

1 The compliance options available to the owner or operator depend on: (a) which (if any) of the units has a Part 76 NO_x emission limit; and (b) the magnitude(s) of any such limit(s).

2 Compliance options include: (a) opting the non-affected units into the Program; (b) attributing all measured emissions to the affected units; (c) monitoring the non-affected units and using a subtractive methodology; and (d) petitioning EPA for approval of an emission apportionment strategy. The owner or operator must ensure that SO_2 or CO_2 mass emissions from the affected unit(s) are not underestimated.

3 The owner or operator has the same basic compliance options for heat input rate as for SO_2 and CO_2 mass emissions accounting (see preceding footnote). Once the combined heat input rate of the affected units has been quantified, it must be apportioned to the individual affected units, either on the basis of load or according to a strategy that has been approved by petition under §75.66.

4 This option may only be used if the monitored stack or duct cannot be bypassed (e.g., with a damper). The option is also disallowed if the monitored NO_x emission rate is not representative of the emissions discharged to the atmosphere (e.g., if there are additional NO_x emission controls downstream of the monitored location).

5 Coal-fired Acid Rain Program units with this configuration have flue gas desulfurization systems (scrubbers) that reduce SO_2 emissions substantially (90% or more, in most cases). Therefore, during scrubber bypass hours, reporting the maximum potential SO_2 concentration (or, if available, data from a certified SO_2 monitor at the control device inlet) is appropriate.

6 An opacity monitor is not required on the bypass stack if: (a) a Federal, State, or local regulation exempts the bypass stack from opacity monitoring; or (b) An opacity monitor is already installed at the inlet of the add-on emission controls; or (3) if visible emissions observations are made using EPA Method 9 during bypass events.

7 These monitoring systems are required if NO_x mass is calculated by multiplying the NO_x emission rate (lb/mmBtu) by the heat input rate (mmBtu/hr).

8 These monitoring systems are required of NO_x mass is calculated as the product of NO_x concentration (ppm), stack gas flow rate (scfh), and a conversion factor.

9 If heat input reporting is required by the regulation.

10 To use this option, all units using the common stack must have the same F-factor.

11 Available compliance options include: (a) opting the non-affected units into the Program and reporting the combined NO_x mass emissions; (b) attributing all of the NO_x mass emissions measured at the common stack to the affected units; (c) installing a NO_x -diluent monitoring system and a flow monitor on the duct leading from each non-affected unit to the common stack, and petitioning to use a subtractive methodology; or (d) petitioning for approval of a method of apportioning the NO_x mass emissions measured at the common stack to the individual units.

12 Depending on the compliance option used, heat input rate determinations may be necessary at the common stack, in the ductwork to the affected units, in the ductwork of the non-affected units, or some combination of these.

[13] The conditions are: (a) Appendix D must be used to determine the heat input rate; (b) the combustion products must be well-mixed; (c) it must be impossible to bypass the monitored stack or duct (e.g., with dampers); and (d) there must be no NO_x emission controls downstream of the monitored location.

[14] The available compliance options include: (a) attribute all of the Hg mass emissions measured at the common stack to the affected unit(s); (b) install a Hg concentration monitoring system or sorbent trap system and a flow monitor on the duct leading from each non-affected unit to the common stack and petition to use a subtractive methodology for Hg mass (note: if a non-affected unit qualifies for the low mass emissions option under §75.81(b), the Hg monitoring system is not required); or (c) petition to use a method of apportioning the Hg mass measured at the common stack to the individual units

[15] Subpart I of Part 75 does not directly address heat input rate monitoring for this case. However, the provisions of §75.16(e), which are required under Case 12 seem appropriate for this case, also.

APPENDIX III

On-Going QA Test Requirements for Ozone Season-Only Reporters

The following Table summarizes the on-going QA test requirements for sources that: (1) are in the NO_x Budget Program or in the CAIR Ozone Season Trading Program; and (2) are eligible to report NO_x mass emissions data only during the ozone season, rather than year-round; and (3) elect to use this option:

Table III-A: On-Going QA Test Requirements for Ozone Season-Only Reporters

Perform these QA tests...	On these monitoring systems...	At these times...	With these qualifications and exceptions...
Daily calibrations (outside ozone season)	Gas and flow monitors	From the date and hour of any RATA or linearity check passed in the "pre-ozone season period" from 10/1 of previous year through 4/30 of current year; or Throughout the pre-ozone season period, if an ozone season RATA from the previous year is used to validate data in the current ozone season.	--------------------
Daily calibrations (inside ozone season)	Gas and flow monitors	Throughout the ozone season (5/1 through 9/30)	--------------------
Daily interference checks (outside ozone season)	Flow monitors	From the date and hour of any flow RATA passed in the pre-ozone season period	--------------------
Daily interference checks (inside ozone season)	Flow monitors	Throughout the ozone season	-------------------
Flow-to-load ratio or gross heat rate test	Flow monitor	In 2nd and 3rd quarters	• Required only in QA operating quarters • Non load-based units exempted • Complex configurations may be exempted by petition under §75.66

Table III-A (cont'd)

Perform these QA tests...	**On these monitoring systems...**	**At these times...**	**With these qualifications and exceptions...**
Linearity checks (outside ozone season)	Gas monitors	Any time during the pre-ozone season period from 10/1 of previous year through 4/30 of current year	If the test is not completed by 4/30, then either: • A 168 operating hour grace period is allowed if a linearity check was passed in the previous year and if the unit operated for < 336 hours in the last ozone season; or • If the grace period does not apply, and the test is done in the first 168 operating hours of the ozone season, it counts as both the pre-season linearity check and the 2^{nd} quarter test. Conditional data validation may be used.
Linearity checks (inside ozone season)	Gas monitors	In 2^{nd} and 3^{rd} quarters	• The linearity check is required only in QA operating quarters[48]. For 2^{nd} quarter, count only the operating hours in May and June. • If the test is done in first 168 hours of ozone season, it counts as both the pre-season linearity check and the 2^{nd} quarter check. • No grace periods allowed for these checks • A "make-up" test can be performed within the first 168 operating hours of next quarter. Conditional data validation may be used.

Table III-A (cont'd)

Perform these QA tests...	On these monitoring systems...	At these times...	With these qualifications and exceptions...
RATA and Bias test	Gas and flow monitors (Bias test applies to NO_x and flow monitors, only)	Pre-ozone season period from 10/1 of previous year through 4/30 of current year	• Not required if RATA from previous ozone season is able to validate data for part or all of current ozone season • If the results of this RATA qualify for an annual RATA frequency, this RATA may be used to validate data for entire current ozone season • If the results of this RATA require a semiannual frequency, this RATA may be used to validate data for entire current ozone season (if test was performed in the current year) or only through 6/30 of current year (if test was performed in the previous year) • If the RATA is required, but is not completed by 4/30, a 720 operating hour grace period is allowed if a RATA was passed in the previous year and if the unit operated for < 336 hours in the last ozone season • If the RATA is required, but is not completed by 4/30 and the grace period does not apply, the test may be performed inside the current ozone season, using the conditional data validation procedures of § 75.20 (b)(3), subject to certain restrictions.

Table III-A (cont'd)

Perform these QA tests...	On these monitoring systems...	At these times...	With these qualifications and exceptions...
RATA and Bias test	Gas and flow monitors (Bias test applies to NO_x and flow monitors, only)	Inside the ozone season i.e., in 2nd or 3rd quarter	• Required only when a pre-ozone season RATA or a RATA performed during the last ozone season is not able to quality assure data for the entire current ozone season • All required RATAs may be done in the 2nd or 3rd quarter instead of performing RATAs outside the ozone season • An ozone season RATA may be used to validate data for part or all of the next ozone season, if the RATA results qualify for an annual frequency, and if daily calibrations (and interference checks if applicable) are performed from 10/1 of current year through 4/30 of the next year
Flow-to-load ratio or gross heat rate test	Flow monitor	In 2nd and 3rd quarters	• Required only in QA operating quarters • Non load-based units exempted • Complex configurations may be exempted by petition under §75.66
Leak check	DP-type flow monitor	In 2nd and 3rd quarters	• Required only in QA operating quarters

Table III-A (cont'd)

Perform these QA tests...	On these monitoring systems...	At these times...	With these qualifications and exceptions...
Flowmeter accuracy test	Fuel flowmeter	Once every four "fuel flowmeter QA operating quarters"[50]	• Include calendar quarters outside the ozone season when determining the accuracy test deadline • For orifice, nozzle and venturi-type flowmeters, visual inspections are also required every 3 years • The optional fuel flow-to-load or gross heat rate test (see section 2.1.7 of Appendix D) may be performed in the 2nd and 3rd quarters to extend the interval between flowmeter accuracy tests, to up to 20 quarters
NO_x emission rate testing	Appendix E systems	Once every 5 years (20 calendar quarters)	-------

APPENDIX IV
References

APPENDIX IV: References

The following underlined section numbers in **bold** print refer to sections of this guide. The relevant rule citations for each section of the document are listed beneath the section number. All referenced rule sections are from Volume 40 of the Code of Federal Regulations.

Section 1

- §§60.4101 through 60.4176 (i.e., the CAMR rule)
- §72.6
- §§75.1 through 75.84 and Appendices A through K (i.e., the Part 75 rule)
- §§76.5, 76.6, 76.7, and 76.13
- §§ 96.1 through 96.88, and associated SIP regulations (i.e., the NO_x Budget Trading Program)
- §§96.101 through 96.188 (blueprint for CAIR NO_x annual trading program)
- §§96.201 through 96.288 (blueprint for CAIR SO_2 annual trading program)
- §§96.301 through 96.388 (blueprint for CAIR NO_x ozone season trading program)

Section 2.1

- §§60.4110 through 60.4114
- §72.2
- §§72.20 through 72.25
- §96.2
- §§96.10 through 96.14
- §§96.110 through 96.114
- §§96.210 through 96.214
- §§96.310 through 96.314

Section 2.2

- §72.2
- §§75.10 through 75.18
- §75.19
- §§75.40 through 75.48 (Subpart E)
- §75.66
- §§75.81 (a) and (b)
- Appendices D, E and G to Part 75

Section 2.3

- §§75.20
- §75.61(a)(1)
- §75.62

APPENDIX IV: References (cont'd)

Section 2.4

- §72.2
- §§75.10 through 75.19
- §75.20
- §§75.30 through 75.39
- §§75.81 (a) and (b)
- Appendices D, E and G to Part 75

Section 2.5

- §75.19(c)(1)(iv)(D)
- §§1, 2.1 through 2.4, and 2.6 of Part 75, Appendix B
- §§ 2.1.6 and 2.1.7 of Part 75, Appendix D
- § 2.2 of Part 75, Appendix E
- Appendix K to Part 75

Section 2.6

- §60.4174
- §75.53
- §§75.57 through 75.59
- §75.73
- §75.84
- §§96.74, 96.174, 96.274, and 96.374

Section 2.7

- §60.4174
- §§75.60 through 75.64
- §75.73(f)
- §§96.74, 96.174, 96.274, and 96.374

Section 3.1

- §72.2
- §§75.10 through 75.18
- §75.20(d)

Section 3.2

- §72.2
- §75.15
- Appendix K to Part 75

APPENDIX IV: References (cont'd)

Section 3.4

- §75.10(d)

Section 3.5

- Part 75, Appendix F—Equations
- Method 19 in Appendix A-7 to Part 60

Section 3.6

- §75.11(b)
- §75.12(b)
- §75.66
- Part 75, Appendix F—Equations
- Method 19 in Appendix A-7 to Part 60

Section 3.7

- §§75.16 through 75.18
- §75.72
- §75.82

Section 3.8

- §§75.30 through 75.39

Section 4.1

- §72.2

Section 4.2

- §§2.1, 2.2 and 2.3 of Part 75, Appendix D

Section 4.3

- §2.1 of Part 75, Appendix D

Section 4.4

- §§2.2 and 2.3 of Part 75, Appendix D

Section 4.5

- §§3.1, 3.2 and 3.3 of Part 75, Appendix D

APPENDIX IV: References (cont'd)

Section 4.6

- §3.4 of Part 75, Appendix D

Section 4.7

- Table D-4 in §2.2 of Part 75, Appendix D
- Table D-5 in §2.3 of Part 75, Appendix D
- §§2.3.5, 2.3.6, and 2.3.7 of Part 75, Appendix D

Section 4.8

- §72.2
- §1.3 of Part 75, Appendix B
- §§2.1.6 and 2.1.7of Part 75, Appendix D

Section 4.9

- §2.4 of Part 75, Appendix D

Sections 5.0 and 5.1

- §72.2
- §75.74(c)(11)
- §§2.1 and 3.4 of Part 75, Appendix D

Section 5.2

- §2.1 of Part 75, Appendix E

Section 5.3

- §2.4 of Part 75, Appendix E

Section 5.4

- Table D-4 in §2.2 of Part 75, Appendix D
- Table D-5 in §2.3 of Part 75, Appendix D

Section 5.5

- §1.3 of Part 75, Appendix B
- §§2.2 and 2.3 of Part 75, Appendix E

APPENDIX IV: References (cont'd)

Section 5.6

- §2.5 of Part 75, Appendix E

Section 5.7

- §1.1 of Part 75, Appendix E

Section 6.1

- §72.2
- §75.19

Section 6.1.1

- §72.2
- §75.19(a)(1)

Section 6.1.2

- §§75.19(a)(2) through (a)(4)
- §75.20(h)

Section 6.1.3

- §§75.19(c)(1), (c)(3), and (c)(4)

Section 6.1.4

- §75.19(c)(1)(iv)

Section 6.1.5

- §75.19(c)(1)(iv)(C)

Section 6.1.6

- §§75.19(c)(2), (d) and (e)

Section 6.1.7

- §75.19(e)

Section 6.1.8

- §§75.19(b)(2) and (b)(3)

APPENDIX IV: References (cont'd)

Section 6.2

- §§60.4101 through 60.4176
- §§75.80 through 75.84

Section 7.2

- §60.4174(b)
- §75.53
- §75.62
- §§75.73(c) and (e)
- §75.84(e)

Section 7.3

- §60.4173
- §75.61(a)(1)
- §§96.73, 173, 273, and 373

Section 7.4

- §60.4171
- §§75.20(c), (e) and (g)
- §75.70(d)
- §75.80(d)
- §§96.71, 171, 271, and 371

Section 7.5

- §§60.4171(c)(3) and 60.4174(c)
- §75.20(a)(2)
- §75.63
- §75.70(d)
- §75.80(d)
- §§96.71, 171, 271, and 371

Section 7.6

- §60.4171(c)(3)
- §75.20(a)(4)
- §75.70(d)
- §75.80(d)
- §§96.71, 171, 271, and 371

APPENDIX IV: References (cont'd)

Section 7.7

- Appendices A-1 through A-7 to Part 60
- §75.22
- §§5 and 6.5.10 of Part 75, Appendix A

Section 7.8

- §3 of Part 75, Appendix A
- §2.1.5 of Part 75, Appendix D

Section 7.9

- §§2.1 through 2.1.7 of Part 75, Appendix A
- §§2.2.2.1, 5.2, 6.2, 6.3.1, and 6.3.2 of Part 75, Appendix A
- §§2.1.1 and 2.1.4 of Part 75, Appendix B

Section 7.10

- §60.4171
- §75.20(b)
- §75.70(d)
- §75.80(d)
- §§96.71, 171, 271, and 371

Sections 8.1 and 8.2

- §75.21
- §§75.74(c)(2) through (c)(5)
- §§2.1 through 2.4 and 2.6 of Part 75, Appendix B
- §§ 2.1.6 and 2.1.7 of Part 75, Appendix D
- §§2.2 and 2.3 of Part 75, Appendix E
- Appendix K to Part 75

Section 8.3

- §6.2 of Part 75, Appendix A
- §§2.2 and 2.3 of Part 75, Appendix B
- §§2.1.6 and 2.1.7 of Part 75, Appendix D

APPENDIX IV: References (cont'd)

Section 8.4

- §§ 6.2, 6.3.1, 6.3.2, 6.5(b), 6.5.1, 6.5.2, 6.5.2.1, and 7.7 of Part 75, Appendix A
- §§2.1.1, 2.1.1.1, 2.1.1.2, 2.1.5, 2.2.5, and 2.3.1.3 of Part 75, Appendix B

Section 8.5

- §§75.74(c)(2) through (c)(5)

Section 8.6

- §§3.2 and 3.3 of Part 75, Appendix A
- §§ 2.1.4 and 2.2.5(b) of Part 75, Appendix B
- Figure 2 in Appendix B to Part 75

Section 8.7

- §75.61(a)(5)

Section 8.8

- §75.19(e)
- §§1.1 through 1.3 and 1.5 of Part 75, Appendix B

Section 9

- §75.20(b)(3)
- §§75.31 through 75.39
- §75.70(f)
- §75.74(c)(7)
- §75.80(f)
- §2.4 of Part 75, Appendix D
- §2.5 of Part 75, Appendix E
- §5 of Part 75, Appendix G

Section 10

- §60.4174
- §§75.60 through 75.64
- §75.73(f)
- §75.84
- §§96.74, 174, 274, and 374