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temporarily adding section 2.1.7, effective July 17, 1995 through December 31, 1996.

APPENDIX C TO PART 75—MISSING DATA ESTIMATION PROCEDURES

1. PARAMETRIC MONITORING PROCEDURE FOR MISSING SO<sub>2</sub> Concentration or NO<sub>x</sub> EMISSION RATE DATA

1.1 *Applicability*

The owner or operator of any affected unit equipped with post-combustion SO<sub>2</sub> or NO<sub>x</sub> emission controls and SO<sub>2</sub> pollutant concentration monitors and/or NO<sub>x</sub> continuous emission monitoring systems at the inlet and outlet of the emission control system may apply to the Administrator for approval and certification of a parametric, empirical, or process simulation method or model for calculating substitute data for missing data periods. Such methods may be used to parametrically estimate the removal efficiency of the SO<sub>2</sub> of postcombustion NO<sub>x</sub> emission controls which, with the monitored inlet concentration or emission rate data, may be used to estimate the average concentration of SO<sub>2</sub> emissions or average emission rate of NO<sub>x</sub> discharged to the atmosphere. After approval by the Administrator, such method or model may be used for filling in missing SO<sub>2</sub> concentration or NO<sub>x</sub> emission rate data when data from the outlet SO<sub>2</sub> pollutant concentration monitor or outlet NO<sub>x</sub> continuous emission monitoring system have been reported with an annual monitor data availability of 90.0 percent or more.

Base the empirical and process simulation methods or models on the fundamental chemistry and engineering principles involved in the treatment of pollutant gas. On a case-by-case basis, the Administrator may pre-certify commercially available process simulation methods and models.

1.2 *Petition Requirements*

Continuously monitor, determine, and record hourly averages of the estimated SO<sub>2</sub> or NO<sub>x</sub> removal efficiency and of the parameters specified below, at a minimum. The affected facility shall supply additional parametric information where appropriate. Measure the SO<sub>2</sub> concentration or NO<sub>x</sub> emission rate, removal efficiency of the add-on emission controls, and the parameters for at least 2160 unit operating hours. Provide information for all expected operating conditions and removal efficiencies. At least 4 evenly spaced data points are required for a valid hourly average, except during periods of calibration, maintenance, or quality assurance activities, during which 2 data points per hour are sufficient. The Administrator will review all applications on a case-by-case basis.

1.2.1 Parameters for Wet Flue Gas Desulfurization System

1.2.1.1 Number of scrubber modules in operation.

1.2.1.2 Total slurry rate to each scrubber module (gal per min).

1.2.1.3 In-line absorber pH of each scrubber module.

1.2.1.4 Pressure differential across each scrubber module (inches of water column).

1.2.1.5 Unit load (MWe).

1.2.1.6 Inlet and outlet SO<sub>2</sub> concentration as determined by the monitor or missing data substitution procedures.

1.2.1.7 Percent solids in slurry for each scrubber module.

1.2.1.8 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.2 Parameters for Dry Flue Gas Desulfurization System

1.2.2.1 Number of scrubber modules in operation.

1.2.2.2 Atomizer slurry flow rate to each scrubber module (gal per min).

1.2.2.3 Inlet and outlet temperature for each scrubber module (°F).

1.2.2.4 Pressure differential across each scrubber module (inches of water column).

1.2.2.5 Unit load (MWe).

1.2.2.6 Inlet and outlet SO<sub>2</sub> concentration as determined by the monitor or missing data substitution procedures.

1.2.2.7 Any other parameters necessary to verify scrubber removal efficiency, if the Administrator determines the parameters above are not sufficient.

1.2.3 Parameters for Other Flue Gas Desulfurization Systems

If SO<sub>2</sub> control technologies other than wet or dry lime or limestone scrubbing are selected for flue gas desulfurization, a corresponding empirical correlation or process simulation parametric method using appropriate parameters may be developed by the owner or operator of the affected unit, and then reviewed and approved or modified by the Administrator on a case-by-case basis.

1.2.4 Parameters for Post-Combustion NO<sub>x</sub> Emission Controls

1.2.4.1 Inlet air flow rate to the unit (boiler) (mcf/hr).

1.2.4.2 Excess oxygen concentration of flue gas at stack outlet (percent).

1.2.4.3 Carbon monoxide concentration of flue gas at stack outlet (ppm).

1.2.4.4 Temperature of flue gas at outlet of the unit (°F).

1.2.4.5 Inlet and outlet NO<sub>x</sub> emission rate as determined by the NO<sub>x</sub> continuous emission monitoring system or missing data substitution procedures.

1.2.4.6 Any other parameters specific to the emission reduction process necessary to verify the NO<sub>x</sub> control removal efficiency, (e.g., reagent feedrate in gal/mi).

1.3 Correlation of Emissions With Parameters

Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the SO<sub>2</sub> or post-combustion NO<sub>x</sub> emission controls under varying unit operating loads. Equations 1-7 in §75.15 may be used to estimate the percent removal efficiency of the SO<sub>2</sub> emission controls on an hourly basis.

Each parametric data substitution procedure should develop a data correlation procedure to verify the performance of the SO<sub>2</sub> emission controls or post-combustion NO<sub>x</sub> emission controls, along with the SO<sub>2</sub> pollutant concentration monitor and NO<sub>x</sub> continuous emission monitoring system values for varying unit load ranges.

For NO<sub>x</sub> emission rate data, and wherever the performance of the emission controls varies with the load, use the load range procedure provided in section 2.2 of this appendix.

1.4 Calculations

1.4.1 Use the following equation to calculate substitute data for filling in missing (outlet) SO<sub>2</sub> pollutant concentration monitor data.

$$M_o = I_e (1-E)$$

(Eq. C-1)

where,

M<sub>o</sub> = Substitute data for outlet SO<sub>2</sub> concentration, ppm.

I<sub>e</sub> = Recorded inlet SO<sub>2</sub> concentration, ppm.

E = Removal efficiency of SO<sub>2</sub> emission controls as determined by the correlation procedure described in section 1.3 of this appendix.

1.4.2 Use the following equation to calculate substitute data for filling in missing (outlet) NO<sub>x</sub> emission rate data.

$$M_o = I_e (1-E)$$

(Eq. C-2)

where,

M<sub>o</sub> = Substitute data for outlet NO<sub>x</sub> emission rate, lb/mmBtu.

I<sub>e</sub> = Recorded inlet NO<sub>x</sub> emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO<sub>x</sub> emission controls determined by the correlation procedure described in section 1.3 of this appendix.

1.5 Missing Data

1.5.1 If both the inlet and the outlet SO<sub>2</sub> pollutant concentration monitors are unavailable simultaneously, use the maximum inlet SO<sub>2</sub> concentration recorded by the inlet SO<sub>2</sub> pollutant concentration monitor during the previous 720 quality assured monitor op-

erating hours to substitute for the inlet SO<sub>2</sub> concentration in Equation C-1 of this appendix.

1.5.2 If both the inlet and outlet NO<sub>x</sub> continuous emission monitoring systems are unavailable simultaneously, use the maximum inlet NO<sub>x</sub> emission rate for the corresponding unit load recorded by the NO<sub>x</sub> continuous emission monitoring system at the inlet during the previous 2160 quality assured monitor operating hours to substitute for the inlet NO<sub>x</sub> emission rate in Equation C-2 of this Appendix.

1.6 Application

Apply to the Administrator for approval and certification of the parametric substitution procedure for filling in missing SO<sub>2</sub> concentration or NO<sub>x</sub> emission rate data using the established criteria and information identified above. DO not use this procedure until approved by the Administrator.

2. LOAD-BASED PROCEDURE FOR MISSING FLOW RATE AND NO<sub>x</sub> EMISSION RATE DATA

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow (scfh) and NO<sub>x</sub> emission rate (in lb/mmBtu).

2.2 Procedure

2.2.1 For a single unit, establish 10 operating load ranges defined in terms of percent of the maximum hourly gross load of the unit, in gross megawatts (MWge), as shown in Table C-1. For units sharing a common stack monitored with a single flow monitor, the load ranges for flow (but not for NO<sub>x</sub>) may be broken down into 20 equally-sized operating load ranges in increments of 5 percent of the combined maximum hourly gross load of all units utilizing the common stack. For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity or for a unit for which hourly gross load in MWge is not recorded separately, use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia) instead of MWge. Indicate a change in the number of load ranges or the units of loads to be used in the precertification section of the monitoring plan.

TABLE C-1.—DEFINITION OF OPERATING LOAD RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURES

Operating load range	Percent of maximum hourly gross load (%)
1 .....	0-10



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TABLE C-1.—DEFINITION OF OPERATING LOAD RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURES—Continued

Operating load range	Percent of maximum hourly gross load (%)
2	10-20
3	20-30
4	30-40
5	40-50
6	50-60
7	60-70
8	70-80
9	80-90
10	90-100

2.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO<sub>x</sub> continuous emission monitoring system, for each hour of unit operation record a number, 1 through 10 (or 1 through 20 for flow at common stacks), that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour.

2.2.3 Beginning with the first hour of unit operation after installation and certification of the flow monitor or the NO<sub>x</sub> continuous emission monitoring system and continuing thereafter, the data acquisition and handling system must be capable of calculating and recording the following information for each unit operating hour of missing flow or NO<sub>x</sub> data within each identified load range during the shorter of: (1) the previous 2,160 quality assured monitor operating hours (on a rolling basis), or (2) all previous quality assured monitor operating hours.

2.2.3.1 Average of the hourly flow rates reported by a flow monitor, in scfh.

2.2.3.2 The 90th percentile value of hourly flow rates, in scfh.

2.2.3.3 The 95th percentile value of hourly flow rates, in scfh.

2.2.3.4 The maximum value of hourly flow rates, in scfh.

2.2.3.5 Average of the hourly NO<sub>x</sub> emission rate, in lb/mmBtu, reported by a NO<sub>x</sub> continuous emission monitoring system.

2.2.3.6 The 90th percentile value of hourly NO<sub>x</sub> emission rates, in lb/mmBtu.

2.2.3.7 The 95th percentile value of hourly NO<sub>x</sub> emission rates, in lb/mmBtu.

2.2.3.8 The maximum value of hourly NO<sub>x</sub> emission rates, in lb/mmBtu.

2.2.4 Calculate all monitor or continuous emission monitoring system data averages, maximum values, and percentile values determined by this procedure using bias adjusted values in the load ranges.

2.2.5 When a bias adjustment is necessary for the flow monitor and/or the NO<sub>x</sub> continuous emission monitoring system, apply the adjustment factor to all monitor or continu-

ous emission monitoring system data values placed in the load ranges.

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO<sub>x</sub> emission rate data according to the procedures in subpart D of this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26547, 26548, May 17, 1995]

APPENDIX D TO PART 75—OPTIONAL SO<sub>2</sub> EMISSIONS DATA PROTOCOL FOR GAS-FIRED AND OIL-FIRED UNITS

## 1. APPLICABILITY

1.1 This protocol may be used in lieu of continuous SO<sub>2</sub> pollutant concentration and flow monitors for the purpose of determining hourly SO<sub>2</sub> emissions and heat input from: (1) gas-fired units as defined in §72.2 of this chapter; or (2) oil-fired units as defined in §72.2 of this chapter. This optional SO<sub>2</sub> emissions data protocol contains procedures for conducting oil sampling and analysis in section 2.2 of this appendix; the procedures for flow proportional oil sampling and the procedures for manual daily oil sampling may be used for any gas-fired unit or oil-fired unit. In addition, this optional SO<sub>2</sub> emissions data protocol contains two procedures for determining SO<sub>2</sub> emissions due to the combustion of gaseous fuels; these two procedures may be used for any gas-fired unit or oil-fired unit.

1.2 Pursuant to the procedures in §75.20, complete all testing requirements to certify use of this protocol in lieu of a flow monitor and an SO<sub>2</sub> continuous emission monitoring system. Complete all testing requirements no later than the applicable deadline specified in §75.4. Apply to the Administrator for initial certification to use this protocol no later than 45 days after the completion of all certification tests. Whenever the monitoring method is to be changed, reapply to the Administrator for recertification of the new monitoring method.

## 2. PROCEDURE

## 2.1 Flowmeter Measurements

For each hour when the unit is combusting fuel, measure and record the flow of fuel combusted by the unit, except as provided for gas in section 2.1.4 of this appendix. Measure the flow of fuel with an in-line fuel flowmeter and automatically record the data with a data acquisition and handling system, except as provided in section 2.1.4 of this appendix.

2.1.1 Measure the flow of each fuel entering and being combusted by the unit. If a portion of the flow is diverted from the unit without being burned, and that diversion occurs downstream of the fuel flowmeter, an



additional in-line fuel flowmeter is required to account for the unburned fuel. Record the flow of each fuel combusted by the unit as the difference between the flow measured in the pipe leading to the unit and the flow in the pipe diverting fuel away from the unit.

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (i.e., a pipe carrying fuel for multiple units). If the flowmeter is installed in a common pipe header, do one of the following:

2.1.2.1 Measure the fuel flow in the common pipe and combine SO<sub>2</sub> mass emissions for the affected units for recordkeeping and compliance purposes; or

2.1.2.2 Provide information satisfactory to the Administrator on methods for apportioning SO<sub>2</sub> mass emissions and heat input to each of the affected units demonstrating that the method ensures complete and accurate accounting of all emissions regulated under this part. The information shall be provided to the Administrator through a petition submitted by the designated representative under §75.66. Satisfactory information includes apportionment using fuel flow measurements, the ratio of load (in MWe) in each unit to the total load for all units receiving fuel from the common pipe header, or the ratio of steam flow (in 1000 lb/hr) at each unit to the total steam flow for all units receiving fuel from the common pipe header.

2.1.3 For a gas-fired unit or an oil-fired unit that continuously or frequently combusts a supplemental fuel for flame stabilization or safety purposes, measure the flow of the supplemental fuel with a fuel flowmeter meeting the requirements of this appendix.

2.1.4 For an oil-fired unit that uses gas solely for start-up or burner ignition or a gas-fired unit that uses oil solely for start-up or burner ignition a flowmeter for the start-up fuel is not required. Estimate the volume of oil combusted for each start-up or ignition, either by using a fuel flowmeter or by using the dimensions of the storage container and measuring the depth of the fuel in the storage container before and after each start-up or ignition. A fuel flowmeter used solely for start-up or ignition fuel is not subject to the calibration requirements of section 2.1.5 and 2.1.6 of this appendix. Gas combusted solely for start-up or burner ignition does not need to be measured separately.

2.1.5 Each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of  $\pm 2.0$  percent of the upper range value (i.e., maximum calibrated fuel flow rate), either by design or as calibrated and as measured under laboratory conditions by the manufacturer, by an independent laboratory, or by the owner or operator. The flowmeter accuracy must include all error from all parts of the fuel flowmeter

being calibrated based upon the contribution to the error in the flowrate.

2.1.5.1 Use the procedures in the following standards for flowmeter calibration or flowmeter design, as appropriate to the type of flowmeter: ASME MFC-3M-1989 with September 1990 Errata ("Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi"), ASME MFC-4M-1986 (Reaffirmed 1990), "Measurement of Gas Flow by Turbine Meters," American Gas Association Report No. 3, "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines" (October 1990 Edition), Part 2: "Specification and Installation Requirements" (February 1991 Edition) and Part 3: "Natural Gas Applications" (August 1992 edition), (excluding the modified flow-calculation method in Part 3) ASME MFC-5M-1985 ("Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters"), ASME MFC-6M-1987 with June 1987 Errata ("Measurement of Fluid Flow in Pipes Using Vortex Flow Meters"), ASME MFC-7M-1987 (Reaffirmed 1992), "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles," ISO 8316: 1987(E) "Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank," or MFC-9M-1988 with December 1989 Errata ("Measurement of Liquid Flow in Closed Conduits by Weighing Method") for all other flow meter types (incorporated by reference under §75.6 of this part). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology (NIST) standards. Document other procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit and a petition submitted by the designated representative under §75.66(c). If the flowmeter accuracy exceeds  $\pm 2.0$  percent of the upper range value, the flowmeter does not qualify for use under this part.

2.1.5.2 Alternatively, a fuel flowmeter used for the purposes of this part may be calibrated or recalibrated at least annually (or, for fuel flowmeters measuring emergency fuel, backup fuel or fuel usage of peaking units, every four calendar quarters when the unit combusts the fuel measured by the fuel flowmeter) by comparing the measured flow of a flowmeter to the measured flow from another flowmeter which has been calibrated or recalibrated during the previous 365 days using a standard listed in section 2.1.5 of this appendix or other procedure approved by the Administrator under §75.66. Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow



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readings for each meter at each of three different flow levels, corresponding to (1) normal full operating load, (2) normal minimum operating load, and (3) a load point approximately equally spaced between the full and minimum operating loads. Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

$$ACC = \frac{|R-A|}{URV} \times 100 \quad (\text{Eq. D-1})$$

Where:

ACC=Flow meter accuracy as a percentage of the upper range value, including all error from all parts of both flowmeters.

R=Average of the three flow measurements of the reference flow meter.

A=Average of the three measurements of the flow meter being tested.

URV=Upper range value of fuel flow meter being tested (i.e. maximum measurable flow).

If the flow meter accuracy exceeds  $\pm 2.0$  percent of the upper range value at any of the three flow levels, either recalibrate the flow meter until the accuracy is within the performance specification, or replace the flow meter with another one that is within the performance specification. Notwithstanding the requirement for annual calibration of the reference flowmeter, if a reference flowmeter and the flowmeter being tested are within  $\pm 1.0$  percent of the flowrate of each other during all in-place calibrations in a calendar year, then the reference flowmeter does not need to be calibrated before the next in-place calibration. This exception to calibration requirements for the reference flowmeter may be extended for periods up to five calendar years.

## 2.1.6 Quality Assurance

2.1.6.1 Recalibrate each fuel flowmeter to a flowmeter accuracy of  $\pm 2.0$  percent of the upper range value prior to use under this part at least annually (or, for fuel flowmeters measuring emergency fuel, backup fuel or fuel usage of peaking units, every four calendar quarters when the unit combusts the fuel measured by the fuel flowmeter), or more frequently if required by manufacturer specifications. Perform the recalibration using the procedures in section 2.1.5 of this appendix. For orifice-, nozzle-, and venturi-type flowmeters, also recalibrate the flowmeter the following calendar quarter using the procedures in section 2.1.6.2 of this appendix, whenever the fuel flowmeter accuracy during a calibration or test is greater than  $\pm 1.0$  percent of the upper range value, or whenever a visual inspection of the orifice, nozzle, or venturi identifies corrosion since the previous visual inspection.

2.1.6.2 For orifice-, nozzle-, and venturi-type flowmeters that are designed according to the standards in section 2.1.5 of this appendix, satisfy the calibration requirements of this appendix by calibrating the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. In addition, conduct a visual inspection of the orifice, nozzle, or venturi at least annually.

## 2.2 Oil Sampling and Analysis

Perform sampling and analysis of as-fired oil to determine the percentage of sulfur by weight in the oil.

2.2.1 When combusting diesel fuel, sample the diesel fuel either (1) every day the unit combusts diesel fuel, or (2) upon receipt of a shipment of diesel fuel.

2.2.1.1 If the diesel fuel is sampled every day, use either the flow proportional method described in section 2.2.3 of this appendix or the daily manual method described in section 2.2.4 of this appendix.

2.2.1.2 If the diesel fuel is sampled upon delivery, calculate  $SO_2$  emissions using the highest sulfur content of any oil supply combusted in the previous 30 days that the unit combusted oil. Diesel fuel sampling and analysis may be performed either by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that sampling is performed according to ASTM D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under §75.6 of this part).

2.2.2 Perform oil sampling every day the unit is combusting oil except as provided for diesel fuel. Use either the flow proportional method described in section 2.2.3 of this appendix or the daily manual method described in section 2.2.4 of this appendix.

2.2.3 Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177-82 (Reapproved 1990), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products" (incorporated by reference under §75.6), every day the unit is combusting oil. Extract oil at least once every hour and blend into a daily composite sample. The sample composite period may not exceed 24 hr.

2.2.4 Representative as-fired oil samples may be taken manually every day that the unit combusts oil according to ASTM D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under §75.6), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purposes of calculating  $SO_2$  emissions under section 3 of



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this appendix. Use the gross calorific value measured from that day's sample to calculate heat input. If oil supplies with different sulfur contents are combusted on the same day, sample the highest sulfur fuel combusted that day.

NOTE: For units with pressurized fuel flow lines such as some diesel and dual-fuel reciprocating internal combustion engine units, a manual sample may be taken from the point closest to the unit where it is safe to take a sample (including back to the oil tank), rather than just prior to entry to the boiler or combustion chamber. As-delivered manual samples of diesel fuel need not be as-fired.

2.2.5 Split and label each oil sample. Maintain a portion (at least 200 cc) of each sample throughout the calendar year and in all cases for not less than 90 calendar days after the end of the calendar year allowance accounting period. Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129-91, "Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)," ASTM D1552-90, "Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)," ASTM D2622-92, "Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry," or ASTM D4294-90, "Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy" (incorporated by reference under §75.6).

2.2.6 Where the flowmeter records volumetric flow rather than mass flow, analyze oil samples to determine the density or specific gravity of the oil. Determine the density or specific gravity of the oil sample in accordance with ASTM D287-82 (Reapproved 1991), "Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)," ASTM D941-88, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer," ASTM D1217-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer," ASTM D1481-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary," ASTM D1480-91, "Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer," ASTM D1298-85 (Reapproved 1990), "Standard Practice for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method," or ASTM D4052-91, "Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter" (incorporated by reference under §75.6).

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat

content in accordance with ASTM D240-87 (Reapproved 1991), "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter," ASTM D2382-88, "Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method)", or ASTM D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter" (incorporated by reference under §75.6) or any other procedures listed in section 5.5 of appendix F of this part.

2.2.8 Results from the oil sample analysis must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results of the analysis be available within 5 business days, or sooner if practicable.

### 2.3 SO<sub>2</sub> Emissions from Combustion of Gaseous Fuels

Account for the hourly SO<sub>2</sub> mass emissions due to combustion of gaseous fuels for each day when gaseous fuels are combusted by the unit using the procedures in either section 2.3.1 or 2.3.2.

2.3.1 Sample the gaseous fuel daily.

2.3.1.1 Analyze the sulfur content of the gaseous fuel in grain/100 scf using ASTM D1072-90, "Standard Test Method for Total Sulfur in Fuel Gases", ASTM D4468-85 (Reapproved 1989) "Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry," ASTM D5504-94 "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence," or ASTM D3246-81 (Reapproved 1987) "Standard Test Method for Sulfur in Petroleum Gas By Oxidative Microcoulometry" (incorporated by reference under §75.6). The test may be performed by the owner or operator, an outside laboratory, or the gas supplier.

2.3.1.2 Results from the analysis must be available on-site no later than thirty calendar days after the sample is taken.

2.3.1.3 Determine the heat content or gross calorific value for at least one sample each month and use the procedures of section 5.5 of appendix F of this part to determine the heat input for each hour the unit combusted gaseous fuel.

2.3.1.4 Multiply the sulfur content by the hourly metered volume of gas combusted in 100 scf, using Equation D-4 of this appendix.

2.3.2 If the fuel is pipeline natural gas, calculate SO<sub>2</sub> emissions using a default SO<sub>2</sub> emission rate of 0.0006 lb/mmBtu.

2.3.2.1 Use the default SO<sub>2</sub> emission rate of 0.0006 lb/mmBtu and the hourly heat input from pipeline natural gas in mmBtu/hr, as determined using the procedures in section 5.5 of appendix F of this part. Calculate SO<sub>2</sub>



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emissions using Equation D-5 of this appendix.

2.3.2.2 Provide information on the contractual sulfur content from the pipeline gas supplier in the monitoring plan for the unit, demonstrating that the gas has a hydrogen sulfide content of 1 grain/100 scf or less, and a total sulfur content of 20 grain/100 scf or less.

#### 2.4 Missing Data Procedures.

When data from the procedures of this part are not available, provide substitute data using the following procedures.

2.4.1 When sulfur content or oil density data from the analysis of an oil sample or when sulfur content data from the analysis of a gaseous fuel sample are missing or invalid, substitute, as applicable, the highest measured sulfur content or oil density (if using a volumetric oil flowmeter) recorded during the previous 30 days when the unit burned that fuel. If no previous sulfur content data are available, substitute the maximum potential sulfur content of that fuel.

2.4.2 When gross calorific value data from the analysis of an oil sample are missing or invalid, substitute the highest measured gross calorific value recorded during the previous 30 days that the unit burned oil. When gross calorific value data from the analysis of a monthly gaseous fuel sample are missing or invalid, substitute the highest measured gross calorific value recorded during the previous three months that the unit burned gaseous fuel.

2.4.3 Whenever data are missing from any fuel flowmeter that is part of an excepted monitoring system under appendix D or E of this part, where the fuel flowmeter data are required to determine the amount of fuel combusted by the unit, use the procedures in either section 2.4.3.1 or sections 2.4.3.2 and 2.4.3.3 prior to January 1, 1996 and use the procedures in sections 2.4.3.2 and 2.4.3.3 but do not use the procedures in section 2.4.3.1 on or after January 1, 1996 to account for the flow rate of fuel combusted at the unit for each hour during the missing data period.

2.4.3.1 [Reserved]

2.4.3.2 For hours where only one fuel is combusted, substitute for each hour in the missing data period the average of the hourly fuel flow rate(s) measured and recorded by the fuel flowmeter (or flowmeters, where fuel is recirculated) at the corresponding operating unit load range recorded for each missing hour during the previous 720 hours during which the unit combusted that same fuel only. Establish load ranges for the unit using the procedures of section 2 in appendix C of this part for missing volumetric flow rate data. If no fuel flow rate data are available at the corresponding load range, use data from the next higher load range where data are available. If no fuel flow rate data are available at either the corresponding load

range or a higher load range during any hour of the missing data period for that fuel, substitute the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following: (1) the maximum fuel flow rate the unit is capable of combusting or (2) the maximum flow rate that the flowmeter can measure.

2.4.3.3 For hours where two or more fuels are combusted, substitute the maximum hourly fuel flow rate measured and recorded by the flowmeter (or flowmeters, where fuel is recirculated) for the fuel for which data are missing at the corresponding load range recorded for each missing hour during the previous 720 hours when the unit combusted that fuel with any other fuel. For hours where no previous recorded fuel flow rate data are available for that fuel during the missing data period, calculate and substitute the maximum potential flow rate of that fuel for the unit as defined in section 2.4.3.2 of this appendix.

2.4.4. In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, use three years (26,280 clock hours) in place of the prescribed lookback period.

### 3. CALCULATIONS

Use the calculation procedures in section 3.1 of this appendix to calculate SO<sub>2</sub> mass emissions. Where an oil flowmeter records volumetric flow, use the calculation procedures in section 3.2 of this appendix to calculate mass flow of oil. Calculate hourly SO<sub>2</sub> mass emissions from gaseous fuel using the procedures in section 3.3 of this appendix. Calculate hourly heat input for oil and for gaseous fuel using the equations in section 5.5 of Appendix F of this part. Calculate total SO<sub>2</sub> mass emissions and heat input as provided under section 3.4 of this appendix.

#### 3.1 SO<sub>2</sub> Mass Emissions Calculation for Oil

3.1.1 Use the following equation to calculate SO<sub>2</sub> mass emissions per hour (in lb/hr).

$$M_{SO_2} = 2.0 \times M_{oil} \times \%S_{oil} / 100.0$$

(Eq. D-2)

Where:

$M_{SO_2}$  = Hourly mass of SO<sub>2</sub> emitted from combustion of oil, lb/hr.

$M_{oil}$  = Mass of oil consumed per hr, lb/hr.

$\%S_{oil}$  = Percentage of sulfur by weight measured in the sample.

2.0 = Ratio of lb SO<sub>2</sub>/lb S.

3.1.2 Record the SO<sub>2</sub> mass emissions from oil for each hour that oil is combusted.



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## 3.2 Mass Flow Calculation for Oil Using Volumetric Flow

3.2.1 Where the oil flowmeter records volumetric flow rather than mass flow, calculate and record the oil mass flow for each hourly period using hourly oil flow measurements and the density or specific gravity of the oil sample.

3.2.2 Convert density, specific gravity, or API gravity of the oil sample to density of the oil sample at the sampling location's temperature using ASTM D1250-80 (Reapproved 1990), "Standard Guide for Petroleum Measurement Tables" (incorporated by reference under § 75.6 of this part).

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.5 of this appendix, use the following equation to calculate the mass of oil consumed (in lb/hr).

$$M_{oil} = V_{oil} \times D_{oil} \quad (\text{Eq. D-3})$$

where,

$M_{oil}$  = Mass of oil consumed per hr, lb/hr.

$V_{oil}$  = Volume of oil consumed per hr, measured in scf, gal, barrels, or  $m^3$ .

$D_{oil}$  = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or  $lb/m^3$ .

3.2.4 Calculate the hourly heat input to the unit from oil (mmBtu) by multiplying the heat content of the daily oil sample by the hourly oil mass.

3.3 SO<sub>2</sub> Mass Emissions Calculation for Gaseous Fuels

3.3.1 Use the following equation to calculate the SO<sub>2</sub> emissions using the gas sampling and analysis procedures in section 2.3.1 of this appendix:

$$M_{SO_2g} = \left( \frac{2.0}{7000} \right) \times Q_g \times S_g \quad (\text{Eq. D-4})$$

Where:

$M_{SO_2g}$  = Hourly mass of SO<sub>2</sub> emitted due to combustion of gaseous fuel, lb/hr.

$Q_g$  = Hourly metered flow or amount of gaseous fuel combusted, 100 scf/hr.

$S_g$  = Sulfur content of gaseous fuel, in grain/100 scf.

2.0 = Ratio of lb SO<sub>2</sub>/lb S.

7000 = Conversion of grains/100 scf to lb/100 scf.

3.3.2 Use the following equation to calculate the SO<sub>2</sub> emissions using the 0.0006 lb/mmBtu emission rate in section 2.3.2 of this appendix:

$$M_{SO_2g} = ER \times HI_g \quad (\text{Eq. D-5})$$

Where:

$M_{SO_2g}$  = Hourly mass of SO<sub>2</sub> emissions from combustion of pipeline natural gas, lb/hr.

ER = SO<sub>2</sub> emission rate of 0.0006 lb/mmBtu for pipeline natural gas.

$HI_g$  = Hourly heat input of pipeline natural gas, calculated using procedures in appendix F of this part, in mmBtu/hr.

3.3.3 Record the SO<sub>2</sub> mass emissions for each hour when the unit combusts gaseous fuel.

## 3.4 Records and Reports

Calculate and record quarterly and cumulative SO<sub>2</sub> mass emissions and heat input for each calendar quarter and for the calendar year by summing the hourly values. Calculate and record SO<sub>2</sub> emissions and heat input data using a data acquisition and handling system. Report these data in a standard electronic format specified by the Administrator.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26548, 26551, May 17, 1995; 61 FR 25585, May 22, 1996]

APPENDIX E TO PART 75—OPTIONAL NO<sub>x</sub> EMISSIONS ESTIMATION PROTOCOL FOR GAS-FIRED PEAKING UNITS AND OIL-FIRED PEAKING UNITS

## 1. APPLICABILITY

## 1.1 Unit Operation Requirements

This NO<sub>x</sub> emissions estimation procedure may be used in lieu of a continuous NO<sub>x</sub> emission monitoring system (lb/mmBtu) for determining the average NO<sub>x</sub> emission rate and hourly NO<sub>x</sub> rate from gas-fired peaking units and oil-fired peaking units as defined in § 72.2 of this chapter. If a unit's operations exceed the levels required to be a peaking unit, install and certify a continuous NO<sub>x</sub> emission monitoring system no later than December 31 of the following calendar year. The provisions of § 75.12 apply to excepted monitoring systems under this appendix.

## 1.2 Certification

1.2.1 Pursuant to the procedures in § 75.20, complete all testing requirements to certify use of this protocol in lieu of a NO<sub>x</sub> continuous emission monitoring system no later than the applicable deadline specified in § 75.4. Apply to the Administrator for certification to use this method no later than 45 days after the completion of all certification testing. Whenever the monitoring method is to be changed, reapply to the Administrator for certification of the new monitoring method.

1.2.2 If the owner or operator has already successfully completed certification testing of the unit using the protocol of appendix E of part 75 and submitted a certification application under § 75.20(g) prior to \_\_\_\_\_ July 17, 1995, the unit's monitoring system does not need to repeat initial certification testing using the revised procedures published \_\_\_\_\_ May 17, 1995.



## 2. PROCEDURE

## 2.1 Initial Performance Testing

Use the following procedures for: measuring NO<sub>x</sub> emission rates at heat input rate levels corresponding to different load levels; measuring heat input rate; and plotting the correlation between heat input rate and NO<sub>x</sub> emission rate, in order to determine the emission rate of the unit(s).

## 2.1.1 Load Selection

Establish at least four approximately equally spaced operating load points, ranging from the maximum operating load to the minimum operating load. Select the maximum and minimum operating load from the operating history of the unit during the most recent two years. (If projections indicate that the unit's maximum or minimum operating load during the next five years will be significantly different from the most recent two years, select the maximum and minimum operating load based on the projected dispatched load of the unit.) For new gas-fired peaking units or new oil-fired peaking units, select the maximum and minimum operating load from the expected maximum and minimum load to be dispatched to the unit in the first five calendar years of operation.

2.1.2 NO<sub>x</sub> and O<sub>2</sub> Concentration Measurements

Use the following procedures to measure NO<sub>x</sub> and O<sub>2</sub> concentration in order to determine NO<sub>x</sub> emission rate.

2.1.2.1 For boilers, select an excess O<sub>2</sub> level for each fuel (and, optionally, for each combination of fuels) to be combusted that is representative for each of the four or more load levels. If a boiler operates using a single, consistent combination of fuels only, the testing may be performed using the combination rather than each fuel. If a fuel is combusted only for the purpose of testing ignition of the burners for a period of five minutes or less per ignition test or for start-up, then the boiler NO<sub>x</sub> emission rate does not need to be tested separately for that fuel. Operate the boiler at a normal or conservatively high excess oxygen level in conjunction with these tests. Measure the NO<sub>x</sub> and O<sub>2</sub> at each load point for each fuel or consistent fuel combination (and, optionally, for each combination of fuels) to be combusted. Measure the NO<sub>x</sub> and O<sub>2</sub> concentrations according to Method 7E and 3A in appendix A of part 60 of this chapter. Select sampling points as specified in section 5.1, Method 3 in appendix A of part 60 of this chapter. The designated representative for the unit may also petition the Administrator under §75.66 to use fewer sampling points. Such a petition shall include the proposed alternative sampling procedure and information demonstrat-

ing that there is no concentration stratification at the sampling location.

2.1.2.2 For stationary gas turbines, select sampling points and measure the NO<sub>x</sub> and O<sub>2</sub> concentrations at each load point for each fuel or consistent combination of fuels (and, optionally, each combination of fuels) according to appendix A, Method 20 of part 60 of this chapter. For diesel or dual fuel reciprocating engines, measure the NO<sub>x</sub> and O<sub>2</sub> concentrations according to Method 20, but modify Method 20 by selecting a sampling site to be as close as practical to the exhaust of the engine.

2.1.2.3 Allow the unit to stabilize for a minimum of 15 minutes (or longer if needed for the NO<sub>x</sub> and O<sub>2</sub> readings to stabilize) prior to commencing NO<sub>x</sub>, O<sub>2</sub>, and heat input measurements. Determine the average measurement system response time according to section 5.5 of Method 20 in appendix A, part 60 of this chapter. When inserting the probe into the flue gas for the first sampling point in each traverse, sample for at least one minute plus twice the average measurement system response time (or longer, if necessary to obtain a stable reading). For all other sampling points in each traverse, sample for at least one minute plus the average measurement response time (or longer, if necessary to obtain a stable reading). Perform three test runs at each load condition and obtain an arithmetic average of the runs for each load condition. During each test run on a boiler, record the boiler excess oxygen level at 5 minute intervals.

## 2.1.3 Heat Input

Measure the total heat input (mmBtu) and heat input rate during testing (mmBtu/hr) as follows:

2.1.3.1 When the unit is combusting fuel, measure and record the flow of fuel consumed. Measure the flow of fuel with an in-line flowmeter(s) and automatically record the data. If a portion of the flow is diverted from the unit without being burned, and that diversion occurs downstream of the fuel flowmeter, an in-line flowmeter is required to account for the unburned fuel. Install and calibrate in-line flow meters using the procedures and specifications contained in sections 2.1.2, 2.1.3, 2.1.4, and 2.1.5 of appendix D of this part. Correct any gaseous fuel flow rate measured at actual temperature and pressure to standard conditions of 68°F and 29.92 inches of mercury.

2.1.3.2 For liquid fuels, analyze fuel samples taken according to the requirements of section 2.2 of appendix D of this part to determine the heat content of the fuel. Determine heat content of liquid or gaseous fuel in accordance with the procedures in appendix F of this part. Calculate the heat input rate during testing (mmBtu/hr) associated with each load condition in accordance with Equations F-19 or F-20 in appendix F of this



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part and total heat input using Equation E-1 of this appendix. Record the heat input rate at each heat input/load point.

## 2.1.4 Emergency Fuel

The designated representative of a unit that is restricted by its Federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available may petition the Administrator pursuant to the procedures in §75.66 for an exemption from the requirements of this appendix for testing the NO<sub>x</sub> emission rate during combustion of the emergency fuel. The designated representative shall include in the petition a procedure for determining the NO<sub>x</sub> emission rate for the unit when the emergency fuel is combusted, and a demonstration that the permit restricts use of the fuel to emergencies only. The designated representative shall also provide notice under §75.61(a) for each period when the emergency fuel is combusted.

## 2.1.5 Tabulation of Results

Tabulate the results of each baseline correlation test for each fuel or, as applicable, combination of fuels, listing: time of test, duration, operating loads, heat input rate (mmBtu/hr), F-factors, excess oxygen levels, and NO<sub>x</sub> concentrations (ppm) on a dry basis (at actual excess oxygen level). Convert the NO<sub>x</sub> concentrations (ppm) to NO<sub>x</sub> emission rates (to the nearest 0.01 lb/mmBtu) according to Equation F-5 of appendix F of this part or 19-3 in Method 19 of appendix A of part 60 of this chapter, as appropriate. Calculate the NO<sub>x</sub> emission rate in lb/mmBtu for each sampling point and determine the arithmetic average NO<sub>x</sub> emission rate of each test run. Calculate the arithmetic average of the boiler excess oxygen readings for each test run. Record the arithmetic average of the three test runs as the NO<sub>x</sub> emission rate and the boiler excess oxygen level for the heat input/load condition.

## 2.1.6 Plotting of Results

Plot the tabulated results as an x-y graph for each fuel and (as applicable) combination of fuels combusted according to the following procedures.

2.1.6.1 Plot the heat input rate (mmBtu/hr) as the independent (or x) variable and the NO<sub>x</sub> emission rates (lb/mmBtu) as the dependent (or y) variable for each load point. Construct the graph by drawing straight line segments between each load point. Draw a horizontal line to the y-axis from the minimum heat input (load) point.

2.1.6.2 Units that co-fire gas and oil may be tested while firing gas only and oil only instead of testing with each combination of fuels. In this case, construct a graph for each fuel.

2.2 Periodic NO<sub>x</sub> Emission Rate Testing

Retest the NO<sub>x</sub> emission rate of the gas-fired peaking unit or the oil-fired peaking unit prior to the earlier of 3,000 unit operating hours or the 5-year anniversary and renewal of its operating permit under part 72 of this chapter.

2.3 Other Quality Assurance/Quality Control-Related NO<sub>x</sub> Emission Rate Testing

When the operating levels of certain parameters exceed the limits specified below, or where the Administrator issues a notice requesting retesting because the NO<sub>x</sub> emission rate data availability for when the unit operates within all quality assurance/quality control parameters in this section since the last test is less than 90.0 percent, as calculated by the Administrator, complete retesting of the NO<sub>x</sub> emission rate by the earlier of: (1) 10 unit operating days (as defined in section 2.1 of appendix B of this part) or (2) 180 calendar days after exceeding the limits or after the date of issuance of a notice from the Administrator to re-verify the unit's NO<sub>x</sub> emission rate. Submit test results in accordance with §75.60(a) within 45 days of completing the retesting.

2.3.1 For a stationary gas turbine, obtain a list of at least four operating parameters indicative of the turbine's NO<sub>x</sub> formation characteristics, and the recommended ranges for these parameters at each tested load-heat input point, from the gas turbine manufacturer. If the gas turbine uses water or steam injection for NO<sub>x</sub> control, the water/fuel or steam/fuel ratio shall be one of these parameters. During the NO<sub>x</sub>-heat input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the manufacturer's recommended range. Redetermine the NO<sub>x</sub> emission rate-heat input correlation for each fuel and (optional) combination of fuels after continuously exceeding the manufacturer's recommended range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours.

2.3.2 For a diesel or dual-fuel reciprocating engine, obtain a list of at least four operating parameters indicative of the engine's NO<sub>x</sub> formation characteristics, and the recommended ranges for these parameters at each tested load-heat input point, from the engine manufacturer. Any operating parameter critical for NO<sub>x</sub> control shall be included. During the NO<sub>x</sub> heat-input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the manufacturer's recommended range. Redetermine the NO<sub>x</sub> emission rate-heat input correlation for each fuel and (optional) combination of fuels after continuously exceeding the manufacturer's recommended range of any of these



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parameters for one or more successive operating periods totaling more than 16 unit operating hours.

2.3.3 For boilers using the procedures in this appendix, the NO<sub>x</sub> emission rate heat input correlation for each fuel and (optional) combination of fuels shall be redetermined if the excess oxygen level at any heat input rate (or unit operating load) continuously exceeds by more than 2 percentage points O<sub>2</sub> from the boiler excess oxygen level recorded at the same operating heat input rate during the previous NO<sub>x</sub> emission rate test for one or more successive operating periods totaling more than 16 unit operating hours.

#### 2.4 Procedures for Determining Hourly NO<sub>x</sub> Emission Rate

2.4.1 Record the time (hr. and min.), load (MWge or steam load in 1000 lb/hr), fuel flow rate and heat input rate (using the procedures in section 2.1.3 of this appendix) for each hour during which the unit combusts fuel. Calculate the total hourly heat input using Equation E-1 of this appendix. Record the heat input rate for each fuel to the nearest 0.1 mmBtu/hr. During partial unit operating hours or during hours where more than one fuel is combusted, heat input must be represented as an hourly rate in mmBtu/hr, as if the fuel were combusted for the entire hour at that rate (and not as the actual, total heat input during that partial hour or hour) in order to ensure proper correlation with the NO<sub>x</sub> emission rate graph.

2.4.2 Use the graph of the baseline correlation results (appropriate for the fuel or fuel combination) to determine the NO<sub>x</sub> emissions rate (lb/mmBtu) corresponding to the heat input rate (mmBtu/hr). Input this correlation into the data acquisition and handling system for the unit. Linearly interpolate to 0.1 mmBtu/hr heat input rate and 0.01 lb/mmBtu NO<sub>x</sub>.

2.4.3 To determine the NO<sub>x</sub> emission rate for a unit co-firing fuels that has not been tested for that combination of fuels, interpolate between the NO<sub>x</sub> emission rate for each fuel as follows. Determine the heat input rate for the hour (in mmBtu/hr) for each fuel and select the corresponding NO<sub>x</sub> emission rate for each fuel on the appropriate graph. (When a fuel is combusted for a partial hour, determine the fuel usage time for each fuel and determine the heat input rate from each fuel as if that fuel were combusted at that rate for the entire hour in order to select the corresponding NO<sub>x</sub> emission rate.) Calculate the total heat input to the unit in mmBtu for the hour from all fuel combusted using Equation E-1. Calculate a Btu-weighted average of the emission rates for all fuels using Equation E-2 of this appendix.

2.4.4 For each hour, record the critical quality assurance parameters, as identified

in the monitoring plan, and as required by section 2.3 of this appendix.

#### 2.5 Missing Data Procedures

Provide substitute data for each unit electing to use this alternative procedure whenever a valid quality-assured hour of NO<sub>x</sub> emission rate data has not been obtained according to the procedures and specifications of this appendix.

2.5.1 Use the procedures of this section whenever any of the quality assurance/quality control parameters exceeds the limits in section 2.3 of this appendix or whenever any of the quality assurance/quality control parameters are not available.

2.5.2 Substitute missing NO<sub>x</sub> emission rate data using the highest NO<sub>x</sub> emission rate tabulated during the most recent set of baseline correlation tests for the same fuel or, if applicable, combination of fuels.

2.5.3 Maintain a record indicating which data are substitute data and the reasons for the failure to provide a valid quality-assured hour of NO<sub>x</sub> emission rate data according to the procedures and specifications of this appendix.

2.5.4 Substitute missing data from a fuel flowmeter using the procedures in section 2.4.3 of appendix D of this part.

2.5.5 Substitute missing data for gross calorific value of fuel using the procedures in section 2.4.2 of appendix D of this part.

### 3. CALCULATIONS

#### 3.1 Heat Input

Calculate the total heat input by summing the product of heat input rate and fuel usage time of each fuel, as in the following equation:

$$H_T = H_{I_{fuel1}} t_1 + H_{I_{fuel2}} t_2 + H_{I_{fuel3}} t_3 + \dots + H_{I_{lastfuel}} t_{last} \quad (\text{Eq. E-1})$$

Where:

H<sub>T</sub> = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu;

H<sub>I<sub>fuel 1,2,3,...last</sub></sub> = Heat input rate from each fuel during fuel usage time, in mmBtu/hr, as determined using equation F-19 or F-20 in section 5.5 of appendix F of this part, mmBtu/hr;

t<sub>1,2,3,...last</sub> = Fuel usage time for each fuel, rounded up to the nearest .25 hours.

NOTE: For hours where a fuel is combusted for only part of the hour, use the fuel flow rate or mass flow rate during the fuel usage time, instead of the total fuel flow during the hour, when calculating heat input rate using Equation F-19 or F-20.

#### 3.2 F-factors

Determine the F-factors for each fuel or combination of fuels to be combusted according to section 3.3 of appendix F of this part.



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3.3 NO<sub>x</sub> Emission Rate

## 3.3.1 Conversion from Concentration to Emission Rate [Amended]

Convert the NO<sub>x</sub> concentrations (ppm) and O<sub>2</sub> concentrations to NO<sub>x</sub> emission rates (to the nearest 0.01 lb/mmBtu) according to the appropriate one of the following equations: F-5 in appendix F of this part for dry basis concentration measurements, or 19-3 in Method 19 of appendix A of part 60 of this chapter for wet basis concentration measurements.

3.3.2 Quarterly Average NO<sub>x</sub> Emission Rate

Report the quarterly average emission rate (lb/mmBtu) as required in subpart G of this part. Calculate the quarterly average NO<sub>x</sub> emission rate according to Equation F-9 in Appendix F of this part.

3.3.3 Annual Average NO<sub>x</sub> Emission Rate

Report the average emission rate (lb/mmBtu) for the calendar year as required in subpart G of this part. Calculate the average NO<sub>x</sub> emission rate according to equation F-10 in appendix F of this part.

3.3.4 Average NO<sub>x</sub> Emission Rate During Co-firing of Fuels [Amended] (Eq. E-2)

Where:

E<sub>h</sub>=NO<sub>x</sub> emission rate for the unit for the hour, lb/mmBtu;

$$E_h = \frac{\sum_{f=1}^{\text{all fuels}} (E_f \times HI_f t_f)}{H_T}$$

E<sub>f</sub>=NO<sub>x</sub> emission rate for the unit for a given fuel at heat input rate HI<sub>f</sub>, lb/mmBtu;

HI<sub>f</sub>=Heat input rate for a given fuel during the fuel usage time, as determined using equation F-19 or F-20 in section 5.5 of appendix F of this part, mmBtu/hr;

H<sub>T</sub>=Total heat input for all fuels for the hour from Equation E-1;

t<sub>f</sub>=Fuel usage time for each fuel, rounded to the nearest .25 hour.

NOTE: For hours where a fuel is combusted for only part of the hour, use the fuel flow rate or mass flow rate during the fuel usage time, instead of the total fuel flow or mass flow during the hour, when calculating heat input rate using Equation F-19 or F-20.

## 4. QUALITY ASSURANCE/QUALITY CONTROL PLAN

Include a section on the NO<sub>x</sub> emission rate determination as part of the monitoring quality assurance/quality control plan required under §75.21 and appendix B of this part for each gas-fired peaking unit and each oil-fired peaking unit. In this section present information including, but not limited to,

the following: (1) a copy of all data and results from the initial NO<sub>x</sub> emission rate testing, including the values of quality assurance parameters specified in Section 2.3 of this appendix; (2) a copy of all data and results from the most recent NO<sub>x</sub> emission rate load correlation testing; (3) a copy of the unit manufacturer's recommended range of quality assurance- and quality control-related operating parameters.

4.1 Submit a copy of the unit manufacturer's recommended range of operating parameter values, and the range of operating parameter values recorded during the previous NO<sub>x</sub> emission rate test that determined the unit's NO<sub>x</sub> emission rate, along with the unit's revised monitoring plan submitted with the certification application.

4.2 Keep records of these operating parameters for each hour of operation in order to demonstrate that a unit is remaining within the manufacturer's recommended operating range.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26551-26553, May 17, 1995]

## APPENDIX F TO PART 75—CONVERSION PROCEDURES

## 1. APPLICABILITY

Use the procedures in this appendix to convert measured data from a monitor or continuous emission monitoring system into the appropriate units of the standard.

2. PROCEDURES FOR SO<sub>2</sub> EMISSIONS

Use the following procedures to compute hourly, quarterly, and annual SO<sub>2</sub> mass emissions (in lb/hr). Use the procedures in Method 19 in Appendix A to part 60 of this chapter to compute hourly SO<sub>2</sub> emission rates (in lb/mmBtu) for qualifying Phase I technologies.

2.1 When measurements of SO<sub>2</sub> concentration and flow rate are on a wet basis, use the following equation to compute hourly SO<sub>2</sub> mass emissions (in lb/hr).

$$E_h = K C_h Q_h$$

(Eq. F-1)

where,

E<sub>h</sub>=Hourly SO<sub>2</sub> mass emissions, lb/hr.

K=1.660×10<sup>-7</sup> for SO<sub>2</sub>, (lb/scf)/ppm.

C<sub>h</sub>=Hourly average SO<sub>2</sub> concentration, stack moisture basis, ppm.

Q<sub>h</sub>=Hourly average volumetric flow rate, stack moisture basis, scfh.

2.2 When measurements by the SO<sub>2</sub> pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO<sub>2</sub> mass emissions (in lb/hr).



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$$E_h = K C_{hp} Q_{hs} \frac{(100 - \%H_2O)}{100}$$

(Eq. F-2)

where,

 $E_h$ =Hourly SO<sub>2</sub> mass emissions, lb/hr. $K=1.660 \times 10^{-7}$  for SO<sub>2</sub>. (lb/scf)/ppm. $C_{hp}$ =Hourly average SO<sub>2</sub> concentration, ppm (dry). $Q_{hs}$ =Hourly average volumetric flow rate, scfh as measured (wet). $\%H_2O$ =Hourly average stack moisture content, percent by volume.

2.3 Use the following equations to calculate total SO<sub>2</sub> mass emissions for each calendar quarter (Eq. F-3) and for each calendar year (Eq. F-4) in tons.

$$E_q = \frac{\sum_{h=1}^n E_h}{2000}$$

(Eq. F-3)

where,

 $E_q$ =Quarterly total SO<sub>2</sub> mass emissions, tons. $E_h$ =Hourly SO<sub>2</sub> mass emissions, lb/hr. $n$ =Number of hourly SO<sub>2</sub> emissions values during calendar quarter.

2000=Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^4 E_q$$

(Eq. F-4)

where,

 $E_a$ =Annual total SO<sub>2</sub> mass emissions, tons. $E_q$ =Quarterly SO<sub>2</sub> mass emissions, tons. $q$ =Quarters for which  $E_q$  are available during calendar year.

2.4 Round all SO<sub>2</sub> mass emissions to the number of decimal places identified in § 75.50(c) or § 75.54(c) of this part (in lb/hr).

### 3. PROCEDURES FOR NO<sub>x</sub> EMISSION RATE

Use the following procedures to convert continuous emission monitoring system

measurements of NO<sub>x</sub> concentration (ppm) and diluent concentration (percentage) into NO<sub>x</sub> emission rates (in lb/mmBtu). Perform measurements of NO<sub>x</sub> and diluent (O<sub>2</sub> or CO<sub>2</sub>) concentrations on the same moisture (wet or dry) basis.

3.1 When the NO<sub>x</sub> continuous emission monitoring system uses O<sub>2</sub> as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

$$E = K C_h F \frac{20.9}{20.9 - \%O_2}$$

(Eq. F-5)

where,

$K$ ,  $E$ ,  $C_h$ ,  $F$ , and  $\%O_2$  are defined in section 3.3 of this appendix. When measurements are performed on a wet basis, use the equations in Method 19 in Appendix A of part 60 of this chapter.

3.2 When the NO<sub>x</sub> continuous emission monitoring system uses CO<sub>2</sub> as the diluent, use the following conversion procedure:

$$E = K C_h F_c \frac{100}{\%CO_2}$$

(Eq. F-6)

where:

$K$ ,  $E$ ,  $C_h$ ,  $F_c$ , and  $\%CO_2$  are defined in section 3.3 of this appendix.

When CO<sub>2</sub> and NO<sub>x</sub> measurements are performed on a different moisture basis, use the equations in Method 19 in Appendix A of part 60 of this chapter.

3.3 Use the definitions listed below to derive values for the parameters in Equations F-5 and F-6 of this appendix.

3.3.1  $K=1.194 \times 10^{-7}$  (lb/dscf)/ppm NO<sub>x</sub>.3.3.2  $E$ =pollutant emissions, lb/mmBtu.3.3.3  $C_h$ =hourly average pollutant concentration, ppm.3.3.4  $\%O_2$ ,  $\%CO_2$ =oxygen or carbon dioxide volume (expressed as percent O<sub>2</sub> or CO<sub>2</sub>).



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3.3.5 F, F<sub>c</sub>=a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO<sub>2</sub> generated to the caloric value of the fuel combusted (F<sub>c</sub>), respectively. Table 1 lists the values of F and F<sub>c</sub> for different fuels. A minimum concentration of 5.0 percent CO<sub>2</sub> and a maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for measured diluent gas concentration values during unit start-up.

TABLE 1.—F- AND F<sub>c</sub>-FACTORS<sup>1</sup>

Fuel	F-factor (dscf/mmBtu)	F <sub>c</sub> -factor (scf CO <sub>2</sub> /mmBtu)
Coal (as defined by ASTM D388-92):		
Anthracite .....	10,100	1,970
Bituminous and subbituminous .....	9,780	1,800
Lignite .....	9,860	1,910
Oil .....	9,190	1,420

TABLE 1.—F- AND F<sub>c</sub>-FACTORS<sup>1</sup>—Continued

Fuel	F-factor (dscf/mmBtu)	F <sub>c</sub> -factor (scf CO <sub>2</sub> /mmBtu)
Gas:		
Natural gas .....	8,710	1,040
Propane .....	8,710	1,190
Butane .....	8,710	1,250
Wood:		
Bark .....	9,600	1,920
Wood residue .....	9,240	1,830

<sup>1</sup> Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury.

3.3.6 Equations F-7a and F-7b may be used in lieu of the F or F<sub>c</sub> factors specified in Section 3.3.5 of this appendix to calculate an F factor (dscf/mmBtu) on a dry basis or an F<sub>c</sub> factor (scf CO<sub>2</sub>/mmBtu) on either a dry or wet basis.

(Calculate all F- and F<sub>c</sub> factors at standard conditions of 20 °C (68 °F) and 29.92 inches of mercury.)

$$F = \frac{3.64 (\%H) + 1.53 (\%C) + 0.57 (\%S) + 0.14 (\%N) - 0.46 (\%O)}{GCV} \times 10^6$$

(Eq. F-7a)

$$F_c = \frac{321 \times 10^3 (\%C)}{GCV}$$

(Eq. F-7b)

3.3.6.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176-89, "Standard Practice for Ultimate Analysis of Coal and Coke" (solid fuels), ASTM D5291-92, "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants" (liquid fuels) or computed from results using ASTM D1945-91, "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" or ASTM D1946-90, "Standard Practice for Analysis of Reformed Gas by Gas Chromatography" (gaseous fuels) as applicable. (These methods are incorporated by reference under §75.6 of this part.)

3.3.6.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter", ASTM D1989-92 "Standard Test Method for Gross Calorific Value of Coal and Coke by Microprocessor Controlled Isoperibol Calorimeters," or ASTM D3286-91a "Stand-

ard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter" for solid and liquid fuels, and ASTM D240-87 (Reapproved 1991) "Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter", or ASTM D2382-88 "Standard Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method)" for oil; and ASTM D3588-91 "Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density (Specific Gravity) of Gaseous Fuels," ASTM D4891-89 "Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion," GPA Standard 2172 86 "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," GPA Standard 2261-90 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," or ASTM D1826-88, "Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter" for gaseous fuels, as applicable. (These methods are incorporated by reference under §75.6).

3.3.6.3 For affected units that combust a combination of fossil (coal, oil and gas) and nonfossil (e.g., bark, wood, residue, or refuse)



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fuels, the F or F<sub>c</sub> value is subject to the Administrator's approval.

3.3.6.4 For affected units that combust combinations of fossil fuels or fossil fuels and wood residue, prorate the F or F<sub>c</sub> factors determined by Section 3.3.5 of this appendix in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^n X_i F_i \quad F_c = \sum_{i=1}^n X_i (F_c)_i$$

(Eq. F-8)

where,

X<sub>i</sub> = Fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood).

F<sub>i</sub> or (F<sub>c</sub>)<sub>i</sub> = Applicable F or F<sub>c</sub> factor for each fuel type determined in accordance with Section 3.3.5 of this appendix.

n = Number of fuels being combusted in combination.

3.4 Use the following equations to calculate the average NO<sub>x</sub> emission rate for each calendar quarter (Eq. F-9) and the average emission rate for the calendar year (Eq. F-10) in lb/mmBtu.

$$E_q = \sum_{i=1}^n \frac{E_i}{n} \quad (\text{Eq. F-9})$$

where:

E<sub>q</sub> = Quarterly average NO<sub>x</sub> emission rate, lb/mmBtu.

E<sub>i</sub> = Hourly average NO<sub>x</sub> emission rate, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^m \frac{E_i}{m} \quad (\text{Eq. F-10})$$

where:

E<sub>a</sub> = Average NO<sub>x</sub> emission rate for the calendar year, lb/mmBtu.

E<sub>i</sub> = Hourly average NO<sub>x</sub> emission rate, lb/mmBtu.

m = Number of hours for which E<sub>i</sub> is available in the calendar year.

3.5 Round all NO<sub>x</sub> emission rates to the nearest 0.01 lb/mmBtu.

4. PROCEDURES FOR CO<sub>2</sub> MASS EMISSIONS

Use the following procedures to convert continuous emission monitoring system measurements of CO<sub>2</sub> concentration (percentage) and volumetric flow rate (scfh) into CO<sub>2</sub> mass emissions (in tons/day) when the owner or operator uses a CO<sub>2</sub> continuous emission monitoring system (consisting of a CO<sub>2</sub> or O<sub>2</sub> pollutant monitor) and a flow mon-

itoring system to monitor CO<sub>2</sub> emissions from an affected unit.

4.1 When CO<sub>2</sub> concentration is measured on a wet basis, use the following equation to calculate hourly CO<sub>2</sub> mass emissions rates (in tons/hr).

$$E_h = K C_h Q_h \quad (\text{Eq. F-11})$$

where,

E<sub>h</sub> = Hourly CO<sub>2</sub> mass emissions, tons/hr.

K = 5.7 × 10<sup>-7</sup> for CO<sub>2</sub>, (tons/scf) / %CO<sub>2</sub>.

C<sub>h</sub> = Hourly average CO<sub>2</sub> concentration, stack moisture basis, %CO<sub>2</sub>. A minimum concentration of 5.0 percent CO<sub>2</sub> may be substituted for the measured concentration during unit start-up.

Q<sub>h</sub> = Hourly average volumetric flow rate, stack moisture basis, scfh.

4.2 When CO<sub>2</sub> concentration is measured on a dry basis, use Equation F-2 to calculate the hourly CO<sub>2</sub> mass emissions (in tons/hr) with a K-value of 5.7 × 10<sup>-7</sup> (tons/scf) %CO<sub>2</sub>, where E<sub>h</sub> = hourly CO<sub>2</sub> mass emissions, tons/hr and C<sub>hp</sub> = hourly average CO<sub>2</sub> concentration in flue; dry basis, %CO<sub>2</sub>.

4.3 Use the following equations to calculate total CO<sub>2</sub> mass emissions for each calendar quarter (Equation F-12) and for each calendar year (Equation F-13).

$$E_{CO_{2q}} = \sum_{i=1}^{H_R} E_{h_i}$$

(Eq. F-12)

where,

E<sub>CO<sub>2q</sub></sub> = Quarterly total CO<sub>2</sub> mass emissions, tons.

E<sub>h<sub>i</sub></sub> = Hourly CO<sub>2</sub> mass emissions (tons/hr).

H<sub>R</sub> = Number of hourly CO<sub>2</sub> mass emissions available during calendar quarter.

$$E_{CO_{2a}} = \sum_{q=1}^4 E_{CO_{2q}}$$

(Eq. F-13)

where,

E<sub>CO<sub>2a</sub></sub> = Annual total CO<sub>2</sub> mass emissions, tons.

E<sub>CO<sub>2q</sub></sub> = Quarterly total CO<sub>2</sub> mass emissions, tons.

q = Quarters for which E<sub>CO<sub>2q</sub></sub> are available during calendar year.

4.4 For an affected unit, when the owner or operator is continuously monitoring O<sub>2</sub> concentration (in percent by volume) of flue gases using an O<sub>2</sub> monitor, use the equations



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and procedures in section 4.4.1 through 4.4.3 of this appendix to determine hourly CO<sub>2</sub> mass emissions (in tons).

4.4.1 Use appropriate F and F<sub>c</sub> factors from section 3.3.5 of this appendix in the following equation to determine hourly average CO<sub>2</sub> concentration of flue gases (in percent by volume).

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9}$$

(Eq. F-14a)

Where:

CO<sub>2d</sub>=Hourly average CO<sub>2</sub> concentration, percent by volume, dry basis.

F, F<sub>c</sub>=F-factor or carbon-based F<sub>c</sub>-factor from section 3.3.5 of this appendix.

20.9=Percentage of O<sub>2</sub> in ambient air.

O<sub>2d</sub>=Hourly average O<sub>2</sub> concentration, percent by volume, dry basis. A maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for the measured concentration during unit start-up.

or

$$CO_{2w} \frac{100 F_c}{20.9 F} \left[ 20.9 \left( \frac{100 - \%H_2O}{100} \right) - O_{2w} \right]$$

(Eq. F-14b)

Where:

CO<sub>2w</sub>=Hourly average CO<sub>2</sub> concentration, percent by volume, wet basis.

O<sub>2w</sub>=Hourly average O<sub>2</sub> concentration, percent by volume, wet basis. A maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for the measured concentration during unit start-up.

F, F<sub>c</sub>=F-factor or carbon-based F<sub>c</sub>-factor from section 3.3.5 of this appendix.

20.9=Percentage of O<sub>2</sub> in ambient air.

%H<sub>2</sub>O=Moisture content of gas in the stack, percent.

4.4.2 Determine CO<sub>2</sub> mass emissions (in tons) from hourly average CO<sub>2</sub> concentration (percent by volume) using Equation F-11 and the procedure in section 4.1, where O<sub>2</sub> measurements are on a wet basis, or using the procedures in section 4.2 of this appendix, where O<sub>2</sub> measurements are on a dry basis.

#### 5. PROCEDURES FOR HEAT INPUT

Use the following procedures to compute heat input to an affected unit (in mmBtu/hr or mmBtu/day).

5.1 Calculate and record heat input to an affected unit on an hourly basis, except as provided below. The owner or operator may choose to use the provisions specified in

§75.16(e) or in section 2.1.2 of appendix D of this part in conjunction with the procedures provided below to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O<sub>2</sub> or CO<sub>2</sub>) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input (in mmBtu/hr).

5.2.1 When measurements of CO<sub>2</sub> concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100}$$

(Eq. F-15)

where,

HI=Hourly heat input, mmBtu/hr.

Q<sub>w</sub>=Hourly average volumetric flow rate, wet basis, scfh.

F<sub>c</sub>=Carbon-based F-factor, listed in Section 3.3.5 of this appendix for each fuel, scf/mmBtu.



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%CO<sub>2w</sub>=Hourly concentration of CO<sub>2</sub>, percent CO<sub>2</sub> wet basis. A minimum concentration of 5.0 percent CO<sub>2</sub> may be substituted for the measured concentration during unit startup.

5.2.2 When measurements of CO<sub>2</sub> concentration are on a dry basis, use the following equation:

$$HI = Q_h \left[ \frac{(100 - \%H_2O)}{100F_c} \right] \left[ \frac{\%CO_{2d}}{100} \right]$$

(Eq. F-16)

where

HI=Hourly heat input, mmBtu/hr.

Q<sub>h</sub>=Hourly average volumetric flow rate, wet basis, scfh.

F<sub>c</sub>=Carbon-based F-Factor, listed above in Section 3.3.5 of this appendix for each fuel, scf/mmBtu.

%CO<sub>2d</sub>=Hourly concentration of CO<sub>2</sub>, percent CO<sub>2</sub> dry basis. A minimum concentration of 5.0 percent CO<sub>2</sub> may be substituted for the measured concentration during unit startup.

%H<sub>2</sub>O=Moisture content of gas in the stack, percent.

5.2.3 When measurements of O<sub>2</sub> concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{[(20.9/100)(100 - \%H_2O) - \%O_{2w}]}{20.9}$$

(Eq. F-17)

where

HI=Hourly heat input, mmBtu/hr.

Q<sub>w</sub>=Hourly average volumetric flow rate, wet basis, scfh.

F=Dry basis F-Factor, listed above in Section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

%O<sub>2w</sub>=Hourly concentration of O<sub>2</sub>, percent O<sub>2</sub> wet basis. A maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for the measured concentration during unit startup.

%H<sub>2</sub>O=Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O<sub>2</sub> concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[ \frac{(100 - \%H_2O)}{100F} \right] \left[ \frac{(20.9 - \%O_{2d})}{20.9} \right]$$

(Eq. F-18)

where,

HI=Hourly heat input, mmBtu/hr.

Q<sub>w</sub>=Hourly average volumetric flow, wet basis, scfh.

F=Dry basis F-factor, listed above in Section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

%H<sub>2</sub>O=Moisture content of the stack gas, percent.

%O<sub>2d</sub>=Hourly concentration of O<sub>2</sub>, percent O<sub>2</sub> dry basis. A maximum concentration of 14.0 percent O<sub>2</sub> may be substituted for the measured concentration during unit startup.

5.3-5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO<sub>2</sub> emissions or for any affected unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input in mmBtu/hr.

5.5.1 When the unit is combusting oil, use the following equation to calculate hourly heat input.

(Eq. F-19)

$$HI_o = M_o \frac{GCV_o}{10^6} \quad (\text{Eq. F-19})$$

Where:

HI<sub>o</sub>=Hourly heat input from oil, mmBtu/hr.

M<sub>o</sub>=Mass of oil consumed per hour, as determined using procedures in appendix D of this part, in lb, tons, or kg.

GCV<sub>o</sub>=Gross calorific value of oil, as measured daily by ASTM D240-87 (Reapproved 1991), ASTM D2015-91, or ASTM D2382-88, Btu/unit mass (incorporated by reference under §75.6 of this part).

10<sup>6</sup>=Conversion of Btu to mmBtu.

When performing oil sampling and analysis solely for the purpose of the missing data procedures in §75.36, oil samples for measuring GCV may be taken weekly and the procedures specified in appendix D of this part for determining the mass of oil consumed per hour are optional.

5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input from gaseous fuels for each hour.

(Eq. F-20)



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$$HI_g = \frac{Q_g \times GCV_g}{10,000} \quad (\text{Eq. F-20})$$

Where:

$HI_g$ =Hourly heat input from gaseous fuel, mmBtu/hour.

$Q_g$ =Metered flow or amount of gaseous fuel combusted during the hour, hundred cubic feet.

$GCV_g$ =Gross calorific value of gaseous fuel, as determined by sampling at least every month the gaseous fuel is combusted, or as verified by the contractual supplier at least once every month the gaseous fuel is combusted using ASTM D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," or GPA Standard 2261-90 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," Btu/cubic foot (incorporated by reference under §75.6 of this part).

10,000=Conversion factor, (Btu-100 scf)/(mmBtu-scf).

5.5.3 When the unit is combusting coal, use the procedures, methods, and equations in sections 5.5.3.1-5.5.3.3 of this appendix to determine the heat input from coal for each 24-hour period. (All ASTM methods are incorporated by reference under §75.6 of this part.)

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in appendix A to part 60 of this chapter and use ASTM Method D2234-89, "Standard Test Methods for Collection of a Gross Sample of Coal," (incorporated by reference under §75.6) Type I, Conditions A, B, or C and systematic spacing for sampling. (When performing coal sampling solely for the purposes of the missing data procedures in §75.36, use of ASTM D2234-89 is optional, and coal samples may be taken weekly.)

5.5.3.2 Use ASTM D2013-86, "Standard Method of Preparing Coal Samples for Analysis," for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D2015-91, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter", ASTM 1989-92 "Standard Test Method for Gross Calorific Value of Coal and Coke by Microprocessor Controlled Isoperibol Calorimeters," or ASTM 3286-91a "Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter." (All ASTM methods are incorporated by reference under §75.6 of this part.)

On-line coal analysis may also be used if the on-line analytical instrument has been

demonstrated to be equivalent to the applicable ASTM methods under §§75.23 and 75.66.

5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500} \quad (\text{Eq. F-21})$$

(Eq. F-21)

Where:

$HI_c$ =Daily heat input from coal, mmBtu/day.  
 $M_c$ =Mass of coal consumed per day, as measured and recorded in company records, tons.

$GCV_c$ =Gross calorific value of coal sample, as measured by ASTM D3176-89, D1989-92, D3286-91a, or D2015-91, Btu/lb.

500=Conversion of Btu/lb to mmBtu/ton.

5.5.4 For units obtaining heat input values daily instead of hourly, apportion the daily heat input using the fraction of the daily steam load or daily unit operating load used each hour in order to obtain  $HI_i$  for use in the above equations. Alternatively, use the hourly mass of coal consumed in equation F-21.

5.5.5 If a daily fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 30 daily samples. If a monthly fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 3 monthly samples.

5.5.6 If a fuel flow value is not available, use the fuel flowmeter missing data procedures in section 2.4 of appendix D of this part. If a daily coal consumption value is not available, substitute the maximum fuel feed rate during the previous thirty days when the unit burned coal.

5.5.7 Results for samples must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results be available in five business days, or sooner if practicable.

#### 6. PROCEDURE FOR CONVERTING VOLUMETRIC FLOW TO STP

Use the following equation to convert volumetric flow at actual temperature and pressure to standard temperature and pressure.

$$F_{STP} = F_{Actual} (T_{Std}/T_{Stack}) (P_{Stack}/P_{Std})$$

Where:

$F_{STP}$ =Flue gas volumetric flow rate at standard temperature and pressure, scfh.

$F_{Actual}$ =Flue gas volumetric flow rate at actual temperature and pressure, acfh.

$T_{Std}$ =Standard temperature=528 °R.

$T_{Stack}$ =Flue gas temperature at flow monitor location, °R, where °R=460+°F.



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$P_{\text{Stack}}$ =The absolute flue gas pressure=barometric pressure at the flow monitor location + flue gas static pressure, inches of mercury.

$P_{\text{Std}}$ =Standard pressure=29.92 inches of mercury.

7. PROCEDURES FOR SO<sub>2</sub> MASS EMISSIONS AT UNITS WITH SO<sub>2</sub> CONTINUOUS EMISSION MONITORING SYSTEMS DURING THE COMBUSTION OF GASEOUS FUEL

Use the following equation to calculate hourly SO<sub>2</sub> mass emissions as allowed for units with SO<sub>2</sub> continuous emission monitoring systems during the combustion of pipeline natural gas under §75.11(e). These procedures are optional prior to January 1, 1997 and are required on or after January 1, 1997.

$$E_h = (0.0006) HI \quad (\text{Eq. F-23})$$

where,

$E_h$ =Hourly SO<sub>2</sub> mass emissions, lb/hr.

0.0006=Default SO<sub>2</sub> emission rate for pipeline natural gas, lb/mmBtu.

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

[58 FR 3701, Jan. 11, 1993; Redesignated and amended at 60 FR 26553-26556, 26571, May 17, 1995; 61 FR 25585, May 22, 1996]

EFFECTIVE DATE NOTE: At 60 FR 26571, May 17, 1995, appendix F to part 75 was amended by temporarily adding section 7, effective July 17, 1995 through December 31, 1996.

APPENDIX G TO PART 75—  
DETERMINATION OF CO<sub>2</sub> EMISSIONS

1. APPLICABILITY

The procedures in this appendix may be used to estimate CO<sub>2</sub> mass emissions discharged to the atmosphere (in tons/day) as the sum of CO<sub>2</sub> emissions from combustion and, if applicable, CO<sub>2</sub> emissions from sorbent used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emission controls.

2. PROCEDURES FOR ESTIMATING CO<sub>2</sub> EMISSIONS FROM COMBUSTION

Use the following procedures to estimate daily CO<sub>2</sub> mass emissions from the combustion of fossil fuels. The optional procedure in section 2.3 of this appendix may also be used for an affected gas-fired unit. For an affected unit that combusts any nonfossil fuels (e.g., bark, wood, residue, or refuse), either use a CO<sub>2</sub> continuous emission monitoring system or apply to the Administrator for approval of a unit-specific method for determining CO<sub>2</sub> emissions.

2.1 Use the following equation to calculate daily CO<sub>2</sub> mass emissions (in tons/day) from the combustion of fossil fuels. Where fuel flow is measured in a common pipe header (i.e., a pipe carrying fuel for multiple units), the owner or operator may use the procedures in section 2.1.2 of appendix D of this part for combining or apportioning emissions, except that the term "SO<sub>2</sub> mass emissions" is replaced with the term "CO<sub>2</sub> mass emissions."

$$W_{\text{CO}_2} = \frac{(MW_C + MW_{\text{O}_2}) \times W_C}{2,000 MW_C} \quad (\text{Eq. G-1})$$

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Where:

$W_{CO_2}$  = CO<sub>2</sub> emitted from combustion, tons/day.

$MW_c$  = Molecular weight of carbon (12.0).

$MW_{O_2}$  = Molecular weight of oxygen (32.0)

$W_c$  = Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates. Collect at least one fuel sample during each week that the unit combusts coal or oil, one sample per each shipment for diesel fuel, and one fuel sample each month the unit combusts gaseous fuels. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week. Determine the carbon content of each fuel sampling using one of the following methods: ASTM D3178-89 for coal; ASTM D5291-92 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil, or computations based upon ASTM D3238-90 and either ASTM D2502-87 or ASTM D2503-82 (Reapproved 1987) for oil; and computations based on ASTM D1945-91 or ASTM D1946-90 for gas. Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. (All ASTM methods are incorporated by reference under §75.6). Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

2.2 For an affected coal-fired unit, the estimate of daily CO<sub>2</sub> mass emissions given by Equation G-1 may be adjusted to account for carbon retained in the ash using the procedures in either section 2.2.1 through 2.2.3 or section 2.2.4 of this appendix.

2.2.1 Determine the ash content of the weekly sample of coal using ASTM D3174-89 "Standard Test Method for Ash in the Analysis Sample of Coal and Coke From Coal" (incorporated by reference under §75.6 of this part).

2.2.2 Sample and analyze the carbon content of the fly-ash according to ASTM D3178-

89, "Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke" (incorporated by reference under §75.6 of this part).

2.2.3 Discount the estimate of daily CO<sub>2</sub> mass emissions from the combustion of coal given by Equation G-1 by the percent carbon retained in the ash using the following equation:

$$W_{NCO_2} = W_{CO_2} - \left( \frac{MW_{CO_2}}{MW_c} \right) \left( \frac{A\%}{100} \right) \left( \frac{C\%}{100} \right) W_{COAL}$$

where,

$W_{NCO_2}$  = Net CO<sub>2</sub> mass emissions discharged to the atmosphere, tons/day.

$W_{CO_2}$  = Daily CO<sub>2</sub> mass emissions calculated by Equation G-1, tons/day.

$MW_{CO_2}$  = Molecular weight of carbon dioxide (44.0).

$MW_c$  = Molecular weight of carbon (12.0).

A% = Ash content of the coal sample, percent by weight.

C% = Carbon content of ash, percent by weight.

$W_{COAL}$  = Feed rate of coal from company records, tons/day.

2.2.4 The daily CO<sub>2</sub> mass emissions from combusting coal may be adjusted to account for carbon retained in the ash using the following equation:

$$W_{NCO_2} = .99 W_{CO_2}$$

(Eq. G-3)

where,

$W_{NCO_2}$  = Net CO<sub>2</sub> mass emissions from the combustion of coal discharged to the atmosphere, tons/day.

.99 = Average fraction of coal converted into CO<sub>2</sub> upon combustion.

$W_{CO_2}$  = Daily CO<sub>2</sub> mass emissions from the combustion of coal calculated by Equation G-1, tons/day.

2.3 In lieu of using the procedures, methods, and equations in section 2.1 of this appendix, the owner or operator of an affected gas-fired unit as defined under §72.2 of this chapter may use the following equation and records of hourly heat input to estimate hourly CO<sub>2</sub> mass emissions (in tons).

$$W_{CO_2} = \left( \frac{F_c \times H \times U_f \times MW_{CO_2}}{2000} \right) \quad (\text{Eq. G-4})$$

(Eq. G-4)

Where:

$W_{CO_2}$  = CO<sub>2</sub> emitted from combustion, tons/hr.

$F_c$  = Carbon-based F-factor, 1,040 scf/mmBtu for natural gas; 1,420 scf/mmBtu for crude, residual, or distillate oil.



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H = Hourly heat input in mmBtu, as calculated using the procedures in section 5 of appendix F of this part.

Uf=1/385 scf CO<sub>2</sub>/lb-mole at 14.7 psia and 68 °F.

### 3. PROCEDURES FOR ESTIMATING CO<sub>2</sub> EMISSIONS FROM SORBENT

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use either a CO<sub>2</sub> continuous emission monitoring system or an O<sub>2</sub> monitor and a flow monitor, or use the procedures, methods, and equations in sections 3.1 through 3.2 of this appendix to determine daily CO<sub>2</sub> mass emissions from the sorbent (in tons).

3.1 When limestone is the sorbent material, use the equations and procedures in either section 3.1.1 or 3.1.2 of this appendix.

3.1.1 Use the following equation to estimate daily CO<sub>2</sub> mass emissions from sorbent (in tons).

$$SE_{CO_2} = W_{CaCO_3} F_u \frac{MW_{CO_2}}{MW_{CaCO_3}}$$

(Eq. G-5)

where,

SE<sub>CO<sub>2</sub></sub>=CO<sub>2</sub> emitted from sorbent, tons/day.

W<sub>CaCO<sub>3</sub></sub>=CaCO<sub>3</sub> used, tons/day.

F<sub>u</sub>=1.00, the calcium to sulfur stoichiometric ratio.

MW<sub>CO<sub>2</sub></sub>=Molecular weight of carbon dioxide (44).

MW<sub>CaCO<sub>3</sub></sub>=Molecular weight of calcium carbonate (100).

3.1.2 In lieu of using Equation G-5, any owner or operator who operates and maintains a certified SO<sub>2</sub>-diluent continuous emission monitoring system (consisting of an SO<sub>2</sub> pollutant concentration monitor and an O<sub>2</sub> or CO<sub>2</sub> diluent gas monitor), for measuring and recording SO<sub>2</sub> emission rate (in lb/mmBtu) at the outlet to the emission controls and who uses the applicable procedures, methods, and equations in §75.15 of this part to estimate the SO<sub>2</sub> emissions removal efficiency of the emission controls, may use the following equations to estimate daily CO<sub>2</sub> mass emissions from sorbent (in tons).

$$SE_{CO_2} = F_u \frac{W_{SO_2}}{2000} \frac{MW_{CO_2}}{MW_{SO_2}}$$

(Eq. G-6)

where,

SE<sub>CO<sub>2</sub></sub>=CO<sub>2</sub> emitted from sorbent, tons/day.

MW<sub>CO<sub>2</sub></sub>=Molecular weight of carbon dioxide (44).

MW<sub>SO<sub>2</sub></sub>=Molecular weight of sulfur dioxide (64).

W<sub>SO<sub>2</sub></sub>=Sulfur dioxide removed, lb/day, as calculated below using Eq. G-7.

F<sub>u</sub>=1.0, the calcium to sulfur stoichiometric ratio.

and

$$W_{SO_2} = SO_{20} \frac{\%R}{(100 - \%R)} \quad (\text{Eq. G-7})$$

(Eq. G-7)

where:

W<sub>SO<sub>2</sub></sub>=Weight of sulfur dioxide removed, lb/day.

SO<sub>20</sub>=SO<sub>2</sub> mass emissions monitored at the outlet, lb/day, as calculated using the equations and procedures in section 2 of appendix F of this part.

%R=Overall percentage SO<sub>2</sub> emissions removal efficiency, calculated using Equations 1 through 7 in §75.15 using daily instead of annual average emission rates.

3.2 When a sorbent material other than limestone is used, modify the equations, methods, and procedures in Section 3.1 of this appendix as follows to estimate daily CO<sub>2</sub> mass emissions from sorbent (in tons).

3.2.1 Determine a site-specific value for F<sub>u</sub>, defined as the ratio of the number of moles of CO<sub>2</sub> released upon capture of one mole of SO<sub>2</sub>, using methods and procedures satisfactory to the Administrator. Use this value of F<sub>u</sub> (instead of 1.0) in either Equation G-5 or Equation G-6.

3.2.2 When using Equation G-5, replace MW<sub>CaCO<sub>3</sub></sub>, the molecular weight of calcium carbonate, with the molecular weight of the sorbent material that participates in the reaction to capture SO<sub>2</sub> and that releases CO<sub>2</sub>, and replace W<sub>CaCO<sub>3</sub></sub>, the amount of calcium carbonate used (in tons/day), with the amount of sorbent material used (in tons/day).

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4. PROCEDURES FOR ESTIMATING TOTAL CO<sub>2</sub> EMISSIONS

When the affected unit has a wet flue gas desulfurization system, is a fluidized bed boiler, or uses other emission controls with sorbent injection, use the following equation to obtain total daily CO<sub>2</sub> mass emissions (in tons) as the sum of combustion-related emissions and sorbent-related emissions.

$$W_t = W_{CO_2} + SE_{CO_2}$$

(Eq. G-8)

where,

W<sub>t</sub> = Estimated total CO<sub>2</sub> mass emissions, tons/day.

W<sub>CO<sub>2</sub></sub> = CO<sub>2</sub> emitted from fuel combustion, tons/day.

SE<sub>CO<sub>2</sub></sub> = CO<sub>2</sub> emitted from sorbent, tons/day.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26556-26557, May 17, 1995; 61 FR 25585, May 22, 1996]

## APPENDIX H TO PART 75—REVISED TRACEABILITY PROTOCOL NO. 1

This appendix consists of section 3.0.4 of the Quality Assurance Handbook for Air Pollution Measurement Systems, Vol. 3, U.S. Environmental Protection Agency (revised 6/9/87). The Quality Assurance Handbook may be obtained from the Methods Research and Development Division, MD 78-A, Atmospheric Research Exposure and Assessment Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

## 3.0.4. Procedure for NBS-Traceable Certification of Compressed Gas Working Standards Used for Calibration and Audit of Continuous Source Emission Monitors (Revised Traceability Protocol No. 1)

Contents	
Subsection	Title
3.0.4.0	General Information
3.0.4.1	Procedure G1: Assay and Certification of a Compressed Gas Standard Without Dilution
3.0.4.2	References

## 4.0 General Information

## 4.0.1 Purpose and Scope of the Procedure

Section 3.0.4 describes a procedure for assaying the concentration of gaseous pollutant concentration standards and certifying that the assay concentrations are traceable to an authoritative reference concentration standard. This procedure is recommended for certifying the local working concentration standards required by the pollutant monitoring regulations of 40 CFR Part 60<sup>1,2</sup> for the calibration and audit of continuous source emission monitors. The procedure covers

certification of compressed gas (cylinder) standards for CO, CO<sub>2</sub>, NO, NO<sub>2</sub>, and SO<sub>2</sub> (Procedure G1).

## 4.0.2 Reference Standards

Part 60 of the monitoring regulations<sup>1,2</sup> requires that working standards used for calibration and audit of continuous source emission monitors be traceable to either a National Bureau of Standards (NBS) gaseous Standard Reference Material (SRM or a NBS/EPA-approved Certified reference material (CRM)<sup>3</sup>. Accordingly, the reference standard used for assaying and certifying a working standard for these purposes must be an SRM, a CRM, or a suitable intermediate standard (see the next paragraph). SRM cylinder gas standards available from NBS are listed in Table 7.2 at the end of subsection 4.0. A current list of CRM cylinder gases and CRM vendors is available from the Quality Assurance Division (MD-77), Environmental Monitoring Systems Laboratory, U.S. EPA, Research Triangle Park, NC 27711.

The EPA regulations define a "traceable" standard as one which ". . . has been compared and certified, either directly or via not more than one intermediate standard, to a primary standard such as a . . . NBS [gaseous] SRM or . . . CRM"<sup>4,5</sup>. Certification of a working standard directly to an SRM or CRM primary standard is, of course, preferred and recommended because of the lower error. However, an intermediate reference standard is permitted, if necessary. In particular, a *Gas Manufacturer's Intermediate Standard* (see subsection 4.0.2.1) that has been referenced directly to an SRM or a CRM according to Procedure G1 is an acceptable intermediate standard and could be used as the reference standard on that basis. However, purchasers of commercial gas standards referenced to an intermediate standard such as a GMIS should be aware that, according to the above definition, such a standard would have to be used directly for calibration or audit. Since a second intermediate standard is not permitted, such a standard could not be used as a reference standard to certify other standards.

4.0.2.1 *Gas Manufacturer's Intermediate Standard (GMIS)*. A GMIS is a compressed (cylinder) gas standard that has been assayed with direct reference to an SRM or CRM and certified according to Procedure G1, and also meets the following requirements:

1. A candidate GMIS must be assayed a minimum of three (3) times, uniformly spaced over a three (3) month period.
2. Each of the three (or more) assays must be within 1.0 percent of the mean of the three (or more) assays.
3. The difference between the last assay and the first assay must not exceed 1.5 percent of the mean of the three (or more) assays.



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4. The GMIS must be recertified every three months, and the reassay must be within 1.5 percent of the previous certified assay. The recertified concentration of the GMIS is the mean of the previous certified concentration and the reassay concentration.

4.0.2.2 *Recertification of Reference Standards.* Recertification requirements for SRMs and CRMs are specified by NBS and NBS/EPA, respectively. See 4.0.2.1 for GMIS recertification requirements.

## 4.0.3 Using the Procedure

The assay/certification procedure described here is carefully designed to minimize both systematic and random errors in the assay process. Therefore, the procedure should be carried out as closely as possible to the way it is described. Similarly, the assay apparatus has been specifically designed to minimize errors and should be configured as closely as possible to the design specified. Good laboratory practice should be observed in the selection of inert materials (e.g., Teflon, stainless steel, or glass, if possible) and clean, non-contaminating components for use in portions of the apparatus in contact with the candidate or reference gas concentrations.

## 4.0.4 Certification Documentation

Each assay/certification must be documented in a written certification report signed by the analyst and containing at least the following information:

1. Identification number (cylinder number).
2. Certified concentration of the standard, in ppm or mole percent.
3. Balance gas in the standard mixture.
4. Cylinder pressure at certification.
5. Date of the assay/certification.
6. Certification expiration date (see 4.0.6.3).
7. Identification of the reference standard used: SRM number, cylinder number, and concentration for an SRM; cylinder number and concentration for a CRM or GMIS.
8. Statement that the assay/certification was performed according to this section 3.0.4.
9. Identification of the laboratory where the standard was certified and the analyst who performed the certification.
10. Identification of the gas analyzer used for the certification, including the make, model, serial number, the measurement principle, and the date of the last multipoint calibration.

11. All analyzer readings used during the assay/certification and the calculations used to obtain the reported certified value.

12. Chronological record of all certifications for the standard.

Certification concentrations should be reported to 3 significant digits. Certification documentation should be maintained for at least 3 years.

## 4.0.5 Certification Label

A label or tag bearing the information described in items 1 through 9 of subsection 4.0.4 must be attached to each certified gas cylinder.

## 4.0.6 Assay/Certification of Compressed Gas (Cylinder) Standards

4.0.6.1 *Aging of newly-prepared gas standards.* Freshly prepared gas standard concentrations and newly filled gas cylinders must be aged before being assayed and certified. SO<sub>2</sub> concentrations contained in steel cylinders must be aged at least 15 days; other standards must be aged at least 4 days.

4.0.6.2 *Stability test for reactive gas standards.* Reactive gas standards, including nitric oxide (NO), nitrogen dioxide (NO<sub>2</sub>), sulfur dioxide (SO<sub>2</sub>), and carbon monoxide (CO), that have not been previously certified must be tested for stability as follows: Reassay the concentration at least 7 days after the first assay and compare the two assays. If the second assay differs from the first assay by 1.5% or less, the cylinder may be considered stable, and the mean of the two assays should be reported as the certified concentration. Otherwise, age the cylinder for a week or more and repeat the test, using the second and third assays as if they were the first and second assays. Cylinders that are not stable may not be sold and/or used for calibration or audit purposes.

4.0.6.3 *Recertification of compressed gas standards.* Compressed gas standards must be recertified according to this section 3.0.4 within the time limits specified in Table 7.1<sup>3,6,7</sup>. The reassay concentration must be within 5% of the previous certified concentration. If not, the cylinder must be retested for stability (subsection 4.0.6.2). The certified concentration of a recertified standard should be reported as the mean of all assays, unless a clear trend or substantial change suggests that previous assays are no longer valid.

TABLE 7.1.—RECERTIFICATION LIMITS FOR COMPRESSED GAS STANDARDS

Pollutant	Balance gas <sup>1</sup>	Concentration range	Maximum months until recertification for cylinder material	
			Passivated Aluminum	Other
Carbon monoxide .....	N <sub>2</sub> or air .....	≥ 8 ppm .....	36	6



TABLE 7.1.—RECERTIFICATION LIMITS FOR COMPRESSED GAS STANDARDS—Continued

Pollutant	Balance gas <sup>1</sup>	Concentration range	Maximum months until recertification for cylinder material	
			Passivated Aluminum	Other
Nitric oxide .....	N <sub>2</sub> .....	≥ 5 ppm .....	24	6
Sulfur dioxide .....	N <sub>2</sub> or air .....	50–499 ppm .....	24	6
Sulfur dioxide .....	N <sub>2</sub> or air .....	≥ 500 ppm .....	36	6
Oxides of nitrogen .....	Air .....	≥ 100 ppm .....	24	6
Nitrogen dioxide .....	Air .....	≥ 1000 ppm .....	24	6
Carbon dioxide .....	N <sub>2</sub> or air .....	≥ 300 ppm .....	36	18
Carbon dioxide and oxygen, (i.e. blood gas).	N <sub>2</sub> .....	≥ 5% CO <sub>2</sub> , ≥ 0% O <sub>2</sub> .....	36	6
Oxygen .....	N <sub>2</sub> .....	≥ 2 percent .....	36	18
Carbon dioxide and nitrous oxide	Air .....	≥ 300 ppm CO <sub>2</sub> , ≥ 300 ppb N <sub>2</sub> O	36	6
Others not specifically listed .....	.....	.....	6	6
Multicomponent mixtures .....	.....	.....	See <sup>2</sup>	6
Mixtures with lower concentrations.	.....	.....	See <sup>3</sup>	6

<sup>1</sup>When used as a balance gas, "air" is defined as a mixture of O<sub>2</sub> and N<sub>2</sub> where the minimum concentration of O<sub>2</sub> is 10% and the concentration of N<sub>2</sub> is greater than 60%.

<sup>2</sup>This protocol may be used to assay and certify individual components of multicomponent standards, provided that none of the components interferes with the analysis of other components and provided that individual components must not react with each other or with the balance gas. A multicomponent standard can be certified for a period of time equal to that of its most briefly certifiable component. For example, a standard containing 250 ppm sulfur dioxide and 100 ppm carbon monoxide in nitrogen can be certified for 24 months because the shortest certification period is 24 months.

<sup>3</sup>This protocol may be used for the certification of standards with concentrations that may be lower than those listed in Table 7.1. The initial certification period for such a lower concentration standard is 6 months. After this period, the standards may be recertified. If the recertification demonstrates that the standard is not unstable, the second certification period for this lower concentration standard is the same time period as indicated for the corresponding concentration standard listed in Table 7.1.

4.0.6.4 *Minimum cylinder pressure.* No compressed gas cylinder standard should be used when its gas pressure is below 700 kPa (100 psi), as indicated by the cylinder pressure gauge.

4.0.6.5 *Assay/certification of multi-component compressed gas standards.* Procedure G1 may be used to assay and certify individual components of multi-component gas standards, provided that none of the components other than the component being assayed cause a detectable response on the analyzer.

#### 4.0.7 Analyzer Calibration

4.0.7.1 *Basic analyzer calibration requirements.* The assay procedure described in this section 3.0.4 employs a direct ratio referencing technique that inherently corrects for minor analyzer calibration variations (drift) and DOES NOT depend on the absolute accuracy of the analyzer calibration. What is required of the analyzer is as follows: 1) it must have a *linear* response to the pollutant of interest (see subsection 4.0.7.5), 2) it must have good resolution and low noise, 3) its response calibration must be reasonably stable during the assay/certification process, and 4) all assay concentration measurements must fall within the calibrated response range of the analyzer.

4.0.7.2 *Analyzer multipoint calibration.* The gas analyzer used for the assay/certification must have had a multipoint calibration within 3 months of its use when used with this procedure. This calibration is *not* used

to quantitatively interpret analyzer readings during the assay/certification of the candidate gas because a more accurate, direct ratio comparison of the candidate concentration to the reference standard concentration is used. However, this multipoint calibration is necessary to establish the calibrated range of the analyzer and its response linearity.

The multipoint calibration should consist of analyzer responses to at least 5 concentrations, including zero, approximately evenly spaced over the concentration range. Analyzer response units may be volts, millivolts, percent of scale, or other measurable analyzer response units. The upper range limit of the calibrated range is determined by the highest calibration point used. If the analyzer has a choice of concentration ranges, the optimum range for the procedure should be selected and calibrated. Plot the calibration points and compute the linear regression slope and intercept. See subsection 4.0.7.5 for linearity requirements and the use of a mathematical transformation, if needed. The intercept should be less than 1 percent of the upper concentration range limit, and the correlation coefficient (*r*) should be at least 0.999.

4.0.7.3 *Zero and span check and adjustment.* On each day that the analyzer will be used for assay/certification, its response calibration must be checked with a zero and at least one span concentration near the upper concentration range limit. If necessary, the zero and span controls of the analyzer should be adjusted so that the analyzer's response



(i.e. calibration slope) is within about  $\pm 5$  percent of the response indicated by the most recent multipoint calibration. If a zero or span adjustment is made, allow the analyzer to stabilize for at least an hour or more before beginning the assay procedure, since some analyzers drift for a period of time following zero or span adjustment. If the analyzer is not in continuous operation, turn it on and allow it to stabilize for at least 12 hours before the zero and span check.

4.0.7.4 *Pollutant standard for multipoint calibration and zero and span adjustment.* The pollutant standard or standards used for multipoint calibration or zero and span checks or adjustments must be obtained from a compressed gas standard certified traceable to an NBS SRM or a NBS/EPA CRM according to Procedure G1 of this section 3.0.4. This standard need not be the same as the reference standard used in the assay/certification. The zero gas must meet the requirements in subsection 4.0.8.

4.0.7.5 *Linearity of analyzer response.* The direct ratio assay technique used in Procedure G1 requires that the analyzer have a linear response to concentration. Linearity is determined by comparing the quantitative difference between a smoothly-drawn calibration curve based on all calibration points and a straight line drawn between zero and an upper reference point (see Figure 1). This difference is measured in concentration units, parallel to the concentration axis, from a point on the calibration curve to the corresponding point for the same response on the straight line.

For the general linearity requirement, the straight line is drawn between zero and the highest calibration point (Figure 1a). Linearity is then acceptable when no point on the smooth calibration curve deviates from the straight line by more than 1.5 percent of the value of the highest calibration concentration. An alternative linearity requirement is defined on the basis of the actual reference and candidate concentrations to be used for the assay. In this case, the reference and candidate concentrations are plotted on the

calibration curve, and the straight line is drawn from zero to the reference concentration and extrapolated, if necessary, beyond the candidate concentration (Figure 1b). The deviation of the smooth calibration curve from the straight line at the candidate concentration point then must not exceed 0.8 percent of the value of the reference concentration. This latter specification may allow the use of an analyzer having greater nonlinearity when the reference and candidate concentrations are nearly the same.

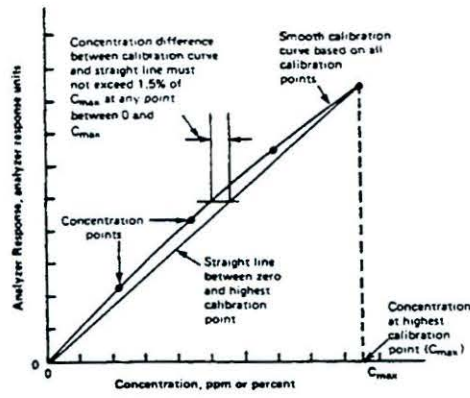
For analyzers having an inherently nonlinear response, the response can usually be linearized with a simple mathematical transformation of the response values, such as  $R' = \sqrt{R}$  or  $R' = \log(R)$ , where  $R'$  is the transformed response value and  $R$  is the actual analyzer response value. Using the transformed response values, the multipoint calibration should meet one of the above linearity requirements as well as the requirements for intercept and correlation coefficient given in subsection 4.0.7.2.

#### 4.0.8 Zero Gas

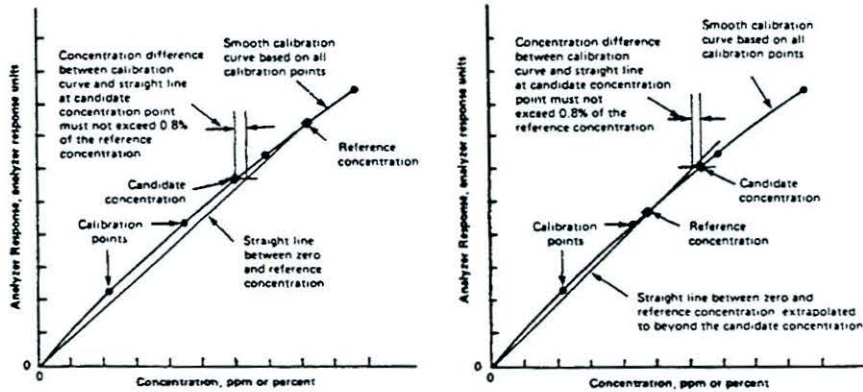
Zero gas used for dilution of any candidate or reference standard should be clean, dry, zero-grade air or nitrogen containing a concentration of the pollutant of interest equivalent to less than 0.5 percent of the analyzer's upper range limit concentration. The zero gas also should contain no contaminant that causes a detectable response on the analyzer or that suppresses or enhances the analyzer's response to the pollutant. The oxygen content of zero air should be the same as that of ambient air.

#### 4.0.9 Accuracy Assessment of Commercially Available Standards

Periodically, the USEPA will assess the accuracy of commercially available compressed gas standards that have been assayed and certified according to this section 3.0.4. Accuracy will be assessed by EPA audit analysis of representative actual commercial standards obtained via an anonymous agent. The accuracy audit results, identifying the actual gas manufacturers or vendors, will be published as public information.



a) General linearity requirement



b) Alternative linearity requirement

Figure 1. Illustration of linearity requirements.



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TABLE 7.2.—NBS SRM REFERENCE GASES

SRM No.	Type	Nominal concentration
2627	NO/N <sub>2</sub>	5 ppm.
2628	NO/N <sub>2</sub>	10 ppm.
2629	NO/N <sub>2</sub>	20 ppm.
1683b	NO/N <sub>2</sub>	50 ppm.
1684b	NO/N <sub>2</sub>	100 ppm.
1685b	NO/N <sub>2</sub>	250 ppm.
1686b	NO/N <sub>2</sub>	500 ppm.
1687b	NO/N <sub>2</sub>	1000 ppm.
2630	NO/N <sub>2</sub>	1500 ppm.
2631	NO/N <sub>2</sub>	3000 ppm.
2653	NO <sub>2</sub> /Air	250 ppm.
2654	NO <sub>2</sub> /Air	500 ppm.
2655	NO <sub>2</sub> /Air	1000 ppm.
2656	NO <sub>2</sub> /Air	2500 ppm.
2612a	CO/Air	10 ppm.
2613a	CO/Air	20 ppm.
2614a	CO/Air	45 ppm.
1677c	CO/N <sub>2</sub>	10 ppm.
2635	CO/N <sub>2</sub>	25 ppm.
1678c	CO/N <sub>2</sub>	50 ppm.
1679c	CO/N <sub>2</sub>	100 ppm.
2636	CO/N <sub>2</sub>	250 ppm.
1680c	CO/N <sub>2</sub>	500 ppm.
1681c	CO/N <sub>2</sub>	1000 ppm.
2637	CO/N <sub>2</sub>	2500 ppm.
2638	CO/N <sub>2</sub>	5000 ppm.
2639	CO/N <sub>2</sub>	1 percent.
2640	CO/N <sub>2</sub>	2 percent.
2641	CO/N <sub>2</sub>	4 percent.
2642	CO/N <sub>2</sub>	8 percent.
2657	O <sub>2</sub> /N <sub>2</sub>	2 percent.
2658	O <sub>2</sub> /N <sub>2</sub>	10 percent.
2659	O <sub>2</sub> /N <sub>2</sub>	21 percent.
1693	SO <sub>2</sub> /N <sub>2</sub>	50 ppm.
1694	SO <sub>2</sub> /N <sub>2</sub>	100 ppm.
1661a	SO <sub>2</sub> /N <sub>2</sub>	500 ppm.
1662a	SO <sub>2</sub> /N <sub>2</sub>	1000 ppm.
1663a	SO <sub>2</sub> /N <sub>2</sub>	1500 ppm.
1664a	SO <sub>2</sub> /N <sub>2</sub>	2500 ppm.
1696	SO <sub>2</sub> /N <sub>2</sub>	3500 ppm.
1670	CO <sub>2</sub> /Air	330 ppm.
1671	CO <sub>2</sub> /Air	340 ppm.
1672	CO <sub>2</sub> /Air	350 ppm.
2632	CO <sub>2</sub> /N <sub>2</sub>	300 ppm.
2633	CO <sub>2</sub> /N <sub>2</sub>	400 ppm.
2634	CO <sub>2</sub> /N <sub>2</sub>	800 ppm.
2619a	CO <sub>2</sub> /N <sub>2</sub>	0.5 percent.
2720a	CO <sub>2</sub> /N <sub>2</sub>	1.0 percent.
2621a	CO <sub>2</sub> /N <sub>2</sub>	1.5 percent.
2622a	CO <sub>2</sub> /N <sub>2</sub>	2.0 percent.
2623a	CO <sub>2</sub> /N <sub>2</sub>	2.5 percent.
2624a	CO <sub>2</sub> /N <sub>2</sub>	3.0 percent.
2625a	CO <sub>2</sub> /N <sub>2</sub>	3.5 percent.
2626a	CO <sub>2</sub> /N <sub>2</sub>	4.0 percent.
1674b	CO <sub>2</sub> /N <sub>2</sub>	7.0 percent.
1675b	CO <sub>2</sub> /N <sub>2</sub>	14.0 percent.
1665b	C <sub>3</sub> H <sub>8</sub> /Air	3 ppm.
1666b	C <sub>3</sub> H <sub>8</sub> /Air	10 ppm.
1667b	C <sub>3</sub> H <sub>8</sub> /Air	50 ppm.
1668b	C <sub>3</sub> H <sub>8</sub> /Air	100 ppm.
1669b	C <sub>3</sub> H <sub>8</sub> /Air	500 ppm.
2643	C <sub>3</sub> H <sub>8</sub> /N <sub>2</sub>	100 ppm.
2644	C <sub>3</sub> H <sub>8</sub> /N <sub>2</sub>	250 ppm.
2645	C <sub>3</sub> H <sub>8</sub> /N <sub>2</sub>	500 ppm.
2646	C <sub>3</sub> H <sub>8</sub> /N <sub>2</sub>	1000 ppm.
2647	C <sub>3</sub> H <sub>8</sub> /N <sub>2</sub>	2500 ppm.
2648	C <sub>3</sub> H <sub>8</sub> /N <sub>2</sub>	5000 ppm.
2649	C <sub>3</sub> H <sub>8</sub> /N <sub>2</sub>	1 percent.
2650	C <sub>3</sub> H <sub>8</sub> /N <sub>2</sub>	2 percent.

NBS-SRM cylinders contain approximately 870 liters of gas at STP.

For availability, contact: Office of Standard Reference Materials, Chemistry Building, Room B311, NBS, Gaithersburg, Maryland 20899, (301) 975-6776. (FTS 879-6776).

#### 4.1 Procedure G1: Assay and Certification of a Compressed Gas Standard Without Dilution

##### 4.1.1 Applicability

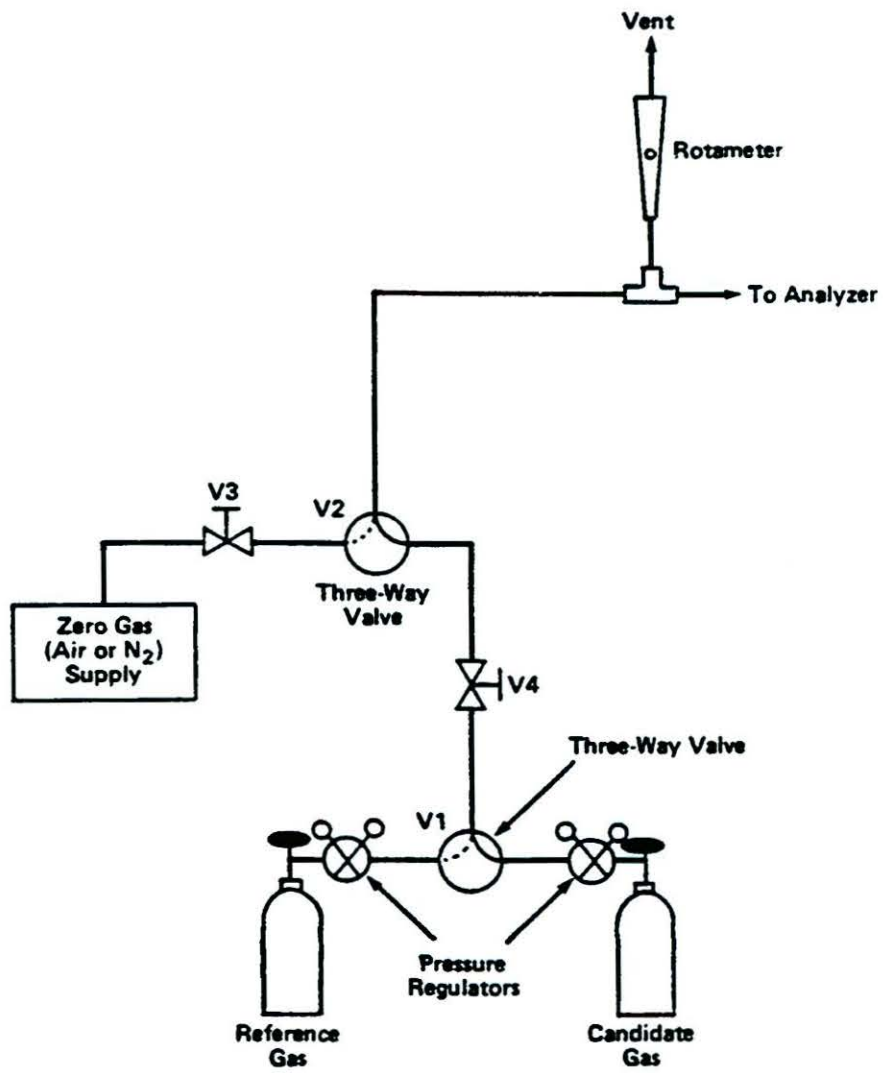
This procedure may be used to assay the concentration of a candidate compressed gas (cylinder) pollutant standard, based on the concentration of a compressed gas (cylinder) reference standard of the same pollutant compound, and certify that the assayed concentration thus established for the candidate standard is traceable to the reference standard. The procedure employs a pollutant gas analyzer to compare the candidate and reference gas concentrations by direct measurement—without dilution of either gas—to minimize assay error.

##### 4.1.2 Limitations

1. The concentration of the candidate gas standard must be between 0.3 and 1.3 times the concentration of the reference gas standard.
2. The analyzer must have a calibrated range capable of directly measuring both the candidate and the reference gas concentrations.
3. The analyzer's response (or transformed response) must be linear with respect to concentration.
4. The balance gas in both the candidate and reference standards must be identical, unless it can be shown that the analyzer is insensitive to any difference in the balance gases.
5. A source of clean, dry zero gas is required.

##### 4.1.3 Assay Apparatus

Figure G1 illustrates the relatively simple assay apparatus. The configuration is designed to allow convenient routing of the zero gas and undiluted samples of the reference gas and candidate gases, in turn, to the analyzer for measurement, as selected by three-way valves V1 and V2. Pressure regulators and needle valves (V3 and V4) control the individual gas flows. The pollutant concentrations are delivered to the analyzer via a vented tee, which discharges excess flow and insures that the assay concentrations sampled by the analyzer are always at a fixed (atmospheric) pressure. A small, uncalibrated rotameter monitors the vent flow to verify that the total gas flow rate exceeds the sample flow rate demand of the analyzer so that no room air is admitted through the vent. Valves V1 and V2 could be replaced by a single four-way valve (with 3 inputs and 1 output) or by manually moving the output connection to each of the gases as needed. See also subsection 4.0.3.





## 4.1.4 Analyzer

See subsection 4.0.7.1. The pollutant gas analyzer must have a linear response function and a calibrated range capable of measuring the full concentration of both the candidate and the reference gas standards directly, without dilution. It must have good resolution (readability), good precision, a stable response, and low output signal noise. In addition, the analyzer must have good specificity for the pollutant of interest so that it has no detectable response to any contaminant that may be contained in either the candidate or reference gas. If the candidate and reference gases contain dissimilar balance gases (air versus nitrogen or different proportions of oxygen in the balance air, for example), the analyzer must be proven to be insensitive to the different balance gases. This may be accomplished by showing no difference in analyzer response when measuring pollutant concentrations diluted with identical flow rates of the two balance gases.

The analyzer should be connected to a suitable, precision chart recorder or other data acquisition device to facilitate graphical observation and documentation of the analyzer responses obtained during the assay.

## 4.1.5 Analyzer Calibration

4.1.5.1 *Multipoint calibration.* See subsections 4.0.7.2 and 4.0.7.4.

4.1.5.2 *Calibration range.* The calibrated range of the analyzer must include both the candidate and reference gas concentrations, such that the higher concentration does not exceed 97 percent of the upper range limit, and the lower concentration is not below 25 percent of the upper range limit (assuming a lower range limit of zero). Within these limits, select a calibrated analyzer range that will produce the highest analyzer responses.

4.1.5.3 *Linearity.* The direct ratio assay technique used in this procedure requires that the analyzer have a linear response to concentration (see subsection 4.0.7.5). High-concentration-range analyzers of the type that are required for this procedure may not be inherently linear, but they usually have a predictable, non-linear response characteristic that can be mathematically transformed to produce a sufficiently linear response characteristic suitable for use in this procedure. Any such response transformation should be verified by using it for the multipoint calibration. Caution should be exercised in using a transformed response curve because physical zero or span adjustments to the analyzer may produce unexpected effects on the transformed characteristic.

4.1.5.4 *Zero and span adjustment.* See subsections 4.0.7.3 and 4.0.7.4. Prior to carrying out the assay/certification procedure, check the calibration of the analyzer and, if nec-

essary, adjust the analyzer's zero and span controls to reestablish the response characteristic determined at the most recent multipoint calibration. Allow the analyzer to stabilize for an hour or more after any zero or span adjustment. If there is any doubt that a transformed response characteristic is still linear following a zero or span adjustment, verify linearity with a multipoint calibration (subsection 4.0.7.2) using at least 3 known pollutant concentrations, including zero.

## 4.1.6 Assay Gases

4.1.6.1 *Candidate gas standard.* See subsections 4.0.6 and 4.1.2.

4.1.6.2 *Reference gas standard.* See subsections 4.0.2, 4.1.2, and 4.0.6.4. Select a reference standard such that the concentration of the candidate gas is not more than 30 percent above nor less than 70 percent below the concentration of the standard.

4.1.6.3 *Zero gas.* See subsection 4.0.8. The zero gas should match the balance gas used in the cylinder concentrations.

## 4.1.7 Assay Procedure

1. Verify that the assay apparatus is properly configured, as described in subsection 4.1.3 and shown in Figure G1.

2. Verify that the linearity of the analyzer has been checked within the last 3 months (see subsections 4.0.7.2, 4.0.7.5, and 4.1.4), that the zero and span are adjusted correctly (subsection 4.0.7.3), that the candidate and reference gas concentrations are within 25 and 97 percent of the upper range limit of the calibrated measurement range of the analyzer, and that the analyzer is operating stably.

3. Adjust the flow rates of the three gases (reference, candidate, and zero) to approximately the same value that will provide enough flow for the analyzer and sufficient excess to assure that no ambient air will be drawn into the vent.

4. Conduct a triad of measurements with the analyzer. Each triad consists of a measurement of the zero gas concentration, a measurement of the reference gas concentration, and a measurement of the candidate gas concentration. Use valves V1 and V2 to select each of the three concentrations for measurement. For each measurement, allow ample time for the analyzer to achieve a stable response reading. Record the stable analyzer response for each measurement, using the same response units (volt, millivolts, percent of scale, etc.) used for the multipoint calibration and any transformation of the response readings necessary for linearity. Do not translate the response readings to concentration values via the calibration curve (see the footnote following Equation G1). Do not make any zero, span, or other physical



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adjustments to the analyzer during the triad of measurements.

5. Conduct at least 2 additional measurement triads, similar to step 4 above. However, for these subsequent triads, change the order of the three measurements (e.g. measure reference gas, zero gas, candidate gas for the second triad and zero gas, candidate gas, reference gas for the third triad, etc.).

6. If any one or more of the measurements of a triad is invalid or abnormal for any reason, discard all three measurements of the triad and repeat the triad.

7. For each triad of measurements, calculate the assay concentration of the candidate gas as follows:

$$C_c = C_r \frac{R_c - R_z}{R_r - R_z}$$

Equation G1

where:

$C_c$ =Assay concentration of the candidate gas standard, ppm or percent;

$C_r$ =Concentration of the reference gas standard, ppm or percent;

$R_c$ =Stable response reading of the analyzer for the candidate gas, analyzer response units\*;

$R_z$ =Stable response reading of the analyzer for the zero gas, analyzer response units\*;

$R_r$ =Stable response reading of the analyzer for the reference gas, analyzer response units.\*

\*Analyzer response units are the units used to express the *direct* response readings of the analyzer, such as volts, millivolts, percent of scale, etc. DO NOT convert these direct response readings to concentration units with the multipoint calibration curve or otherwise adjust these readings except for transformation necessary to achieve response linearity.

8. Calculate the mean of the 3 (or more) valid assays. Calculate the percent difference of each assay from the mean. If any one of the assay values differs from the mean by more than 1.5%, discard that assay value and conduct another triad of measurements to obtain another assay value. When at least 3 assay values all agree within 1.5% of their mean, report the mean value as the certified concentration of the candidate gas standard. For newly-prepared reactive standards, a re-assay at least 7 days later is required to check the stability of the standard; see subsection 4.0.6.2.

## 4.1.8 Stability Test for Newly-Prepared Standards

See subsections 4.0.6.1 and 4.0.6.2.

## 4.1.9 Certification Documentation

See subsections 4.0.4 and 4.0.5.

## 4.1.10 Recertification Requirements

See subsections 4.0.6.3 and 4.0.6.4.

## 4.2 References

1. Code of Federal Regulations, title 40, part 60, "Standards of Performance for New Stationary Sources," appendix A, Method 20 (1982).

2. Standards of Performance for New Stationary Sources; Quality Assurance Requirements for Gaseous Continuous Emission Monitoring Systems Used for Compliance Determination, promulgated in the FEDERAL REGISTER, June 4, 1987, pp. 21003-21010.

3. "A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials. EPA-600/7-81-010. Joint publication by NBS and EPA, May 1981. Available from the U.S. Environmental Protection Agency, Environmental Monitoring Systems Laboratory (MD-77), Research Triangle Park, NC 27711.

4. Code of Federal Regulation, title 40, part 50, "National Ambient Air Quality Measurement Methodology".

5. Code of Federal Regulations, title 40, part 58, "Ambient Air Quality Surveillance," appendixes A and B.

6. Shores, R.C. and F. Smith, "Stability Evaluation of Sulfur Dioxide, Nitric Oxide, and Carbon Monoxide Gases in Cylinders". NTIS No. PB 85-122646. Available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161.

7. Method 6A and 6B, "Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions from Fossil Fuel Combustion Sources," Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Section 3.13.8, July 1986. Available from the U.S. Environmental Protection Agency, Center for Environmental Research Information, Cincinnati, OH 45268.

8. "List of Designated Reference and Equivalent Methods." Current edition available from the U.S. Environmental Protection Agency, Environmental Monitoring Systems Laboratory, Quality Assurance Division (MD-77), Research Triangle Park, NC 27711.

[58 FR 3701, Jan. 11, 1993; 58 FR 40751, 40752, July 30, 1993]



## Pt. 75, App. J

## 40 CFR Ch. I (7-1-96 Edition)

APPENDIX I TO PART 75—OPTIONAL F—  
FACTOR/FUEL FLOW METHOD [RESERVED]

APPENDIX J TO PART 75—COMPLIANCE  
DATES FOR REVISED RECORDKEEPING  
REQUIREMENTS AND MISSING DATA  
PROCEDURES

1. *Recordkeeping Requirements*

The owner or operator shall meet the recordkeeping requirements of subpart F of this part by following either §§75.50, 75.51 and 75.52 or §§75.54, 75.55 and 75.56, from July 17, 1995 through December 31, 1995. On or after January 1, 1996, the owner or operator shall meet the recordkeeping requirements of subpart F of this part by meeting the requirements of §§75.54, 75.55, and 75.56.

2. *Missing Data Substitution Procedures*

The owner or operator shall meet the missing data substitution requirements for carbon dioxide (CO<sub>2</sub>) and heat input by following either §§75.35 and 75.36 or sections 4.3.1 through 4.3.3, section 4.4.3 and sections 5.3 through 5.4 of appendix F of this part from July 17, 1995 through December 31, 1995. The owner or operator shall meet the missing data substitution requirements for fuel flowmeters in appendix D of this part by following either section 2.4.3.1 or sections 2.4.3.2 and 2.4.3.3 of appendix D of this part from July 17, 1995 through December 31, 1995. On or after January 1, 1996, the owner or operator shall meet the missing data substitution requirements for CO<sub>2</sub> concentration, that input and fuel flowmeters by meeting the requirements of §§75.35 and 75.36 and sections 2.4.3.2 through 2.4.3.3 of appendix D of this part.

[60 FR 26557, May 17, 1995]

**PART 76—ACID RAIN NITROGEN  
OXIDES EMISSION REDUCTION  
PROGRAM**

Sec.

- 76.1 Applicability.
- 76.2 Definitions.
- 76.3 General Acid Rain Program provisions.
- 76.4 Incorporation by reference.
- 76.5 NO<sub>x</sub> emission limitations for Group 1 boilers.
- 76.6 NO<sub>x</sub> emission limitations for Group 2 boilers. [Reserved]
- 76.7 Revised NO<sub>x</sub> emission limitations for Group 1, Phase II boilers. [Reserved]
- 76.8 Early election for Group 1, Phase II boilers.
- 76.9 Permit application and compliance plans.
- 76.10 Alternative emission limitations.
- 76.11 Emissions averaging.
- 76.12 Phase I NO<sub>x</sub> compliance extensions.

- 76.13 Compliance and excess emissions.
- 76.14 Monitoring, recordkeeping, and reporting.
- 76.15 Test methods and procedures.
- 76.16 [Reserved]

APPENDIX A TO PART 76—PHASE I AFFECTED  
COAL-FIRED UTILITY UNITS WITH GROUP 1  
OR CELL BURNER BOILERS

APPENDIX B TO PART 76—PROCEDURES AND  
METHODS FOR ESTIMATING COSTS OF NI-  
TROGEN OXIDES CONTROLS APPLIED TO  
GROUP 1, PHASE I BOILERS

AUTHORITY: 42 U.S.C. 7601 and 7651 *et seq.*

SOURCE: 60 FR 18761, Apr. 13, 1995, unless otherwise noted.

**§76.1 Applicability.**

(a) Except as provided in paragraphs (b) through (d) of this section, the provisions apply to each coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for SO<sub>2</sub> under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Act.

(b) The emission limitations for NO<sub>x</sub> under this part apply to each affected coal-fired utility unit subject to section 404(d) or 409(b) of the Act on the date the unit is required to meet the Acid Rain emissions reduction requirement for SO<sub>2</sub>.

(c) The provisions of this part apply to each coal-fired substitution unit or compensating unit, designated and approved as a Phase I unit pursuant to §72.41 or §72.43 of this chapter as follows:

(1) A coal-fired substitution unit that is designated in a substitution plan that is approved and active as of January 1, 1995 shall be treated as a Phase I coal-fired utility unit for purposes of this part. In the event the designation of such unit as a substitution unit is terminated after December 31, 1995, pursuant to §72.41 of this chapter and the unit is no longer required to meet Phase I SO<sub>2</sub> emissions limitations, the provisions of this part (including those applicable in Phase I) will continue to apply.

(2) A coal-fired substitution unit that is designated in a substitution plan that is not approved or not active as of January 1, 1995, or a coal-fired compensating unit, shall be treated as a Phase II coal-fired utility unit for purposes of this part.



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