

TABLE D-4.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST—Continued

Time period	
Baseline period	Quarter
____/____/____ :____ End date and time of baseline period: ____/____/____ :____ Average fuel flow rate:_____ (100 scfh for gas and lb/hr for oil) Average load:_____ (MWe or 1000 lb steam/hr)	Number of hours included in quarterly average:____ hrs. Quarterly percentage difference between hourly ratios and baseline ratio:____ percent. Test result: pass, fail
Plant name:____ State:____ ORIS code:____ Unit/pipe ID#:____ Fuel flowmeter component and system ID #:____-____ Calendar quarter (1st, 2nd, 3rd, 4th) and year:____ Range of operation:____ MWe or klb steam/hr (indicate units)	

Time period	
Baseline fuel flow-to-load ratio:_____ Units of fuel flow-to-load:_____ Baseline GHR:_____ Units of fuel flow-to-load:_____ Number of hours excluded from baseline ratio or GHR due to ramping load:____ hrs. Number of hours in the lower 10.0 percent of the range of operation excluded from baseline ratio or GHR:____ hrs.	

2.2 Oil Sampling and Analysis

Perform sampling and analysis of oil to determine the percentage of sulfur by weight

in the oil combusted by the unit. Calculate SO₂ mass emissions and heat input rate using the sulfur content, density, and gross

calorific value (heat content), as described in the sections below and in Table D-5.

TABLE D-5.—OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations
Oil Sulfur Content.. .. .	Daily manual sampling	Highest sulfur content from previous 30 daily samples.
	Flow proportional/weekly composite..	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract. ¹
	As delivered (in delivery truck or barge). ¹	Highest of all sampled values in previous calendar year OR maximum value allowed by contract. ¹
Oil Density	Daily manual sampling	Actual measured value.
	Flow proportional/weekly composite..	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract. ¹
	As delivered (in delivery truck or barge). ¹	Highest of all sampled values in previous calendar year OR maximum value allowed by contract. ¹
Oil GCV	Daily manual sampling	Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract. ¹
	As delivered (in delivery truck or barge). ¹	Highest of all sampled values in previous calendar year OR maximum value allowed by contract. ¹

¹ Assumed values may only be used if sulfur content, gross calorific value, or density of each sample is no greater than the assumed value used to calculate emissions or heat input.

2.2.1 When combusting oil, sample the oil: (1) from the storage tank for the unit after each addition of oil to the storage tank, in accordance with section 2.2.4.2 of this appendix; (2) from the fuel lot in the shipment tank or container upon receipt of each oil delivery or from the fuel lot in the oil supplier's storage container, in

accordance with section 2.2.4.3 of this appendix; (3) following the flow proportional sampling methodology in section 2.2.3 of this appendix; or (4) following the daily manual sampling methodology in section 2.2.4.1 of this appendix. For purposes of this appendix, a fuel lot of oil is the mass or volume of product oil from one source (supplier or

pretreatment facility), intended as one shipment or delivery (ship load, barge load, group of trucks, discrete purchase of diesel fuel through pipeline, etc.), which meets the fuel purchase specifications for sulfur content and GCV. A storage tank is a container at a plant holding oil that is actually combusted by the unit, such that

blending of any other fuel with the fuel in the storage tank occurs from the time that the fuel lot is transferred to the storage tank to the time when the fuel is combusted in the unit.

2.2.2 [Reserved]

2.2.3 Flow Proportional Sampling

Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177-82 (Reapproved 1990), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6), every day the unit is combusting oil. Extract oil at least once every hour and blend into a composite sample. The sample compositing period may not exceed 7 calendar days (168 hr). Use the actual sulfur content (and where density data are required, the actual density) from the composite sample to calculate the hourly SO₂ mass emission rates for each operating day represented by the composite sample. Calculate the hourly heat input rates for each operating day represented by the composite sample, using the actual gross calorific value from the composite sample.

2.2.4 Manual Sampling

2.2.4.1 Daily Samples

Representative oil samples may be taken from the storage tank or fuel flow line manually every day that the unit combusts oil according to ASTM D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purpose of calculating SO₂ emissions under section 3 of this appendix. Use the gross calorific value measured from that day's samples to calculate heat input. If oil supplies with different sulfur contents are combusted on the same day, sample the highest sulfur fuel combusted that day.

2.2.4.2 Sampling from a Unit's Storage Tank

Take a manual sample after each addition of oil to the storage tank. No additional fuel shall be blended with the sampled fuel prior to combustion. Sample according to the single tank composite sampling procedure or all-levels sampling procedure in ASTM

D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6). Use the sulfur content (and where required, the density) of either the most recent sample or one of the conservative assumed values described in section 2.2.4.3 of this appendix, to calculate SO₂ mass emission rate. Calculate heat input rate using the gross calorific value from either: (1) the most recent oil sample taken or (2) one of the conservative assumed values described in section 2.2.4.3 of this appendix.

2.2.4.3 Sampling from Each Delivery

Alternatively, an oil sample may be taken from the shipment tank or container upon receipt of each lot of fuel oil or from the supplier's storage container which holds the lot of fuel oil. For the purpose of this section, a lot is defined as a shipment or delivery (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through a pipeline, etc.) which meets the fuel purchase specifications for sulfur content and GCV. Oil sampling may be performed either by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that samples are representative and that sampling is performed according to either the single tank composite sampling procedure or the all-levels sampling procedure in ASTM D4057-88, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.6). Except as otherwise provided in this section 2.2.4.3, calculate SO₂ mass emission rate using the sulfur content (and where required, the density) from one of the two values below, and calculate heat input using the gross calorific value from one of the two following values: (1) the highest value sampled during the previous calendar year or (2) the maximum value indicated in the contract with the fuel supplier unit. Continue to use this assumed value unless and until the actual sampled sulfur content, density, or gross calorific value of a delivery exceeds the assumed value.

If the actual sampled sulfur content, gross calorific value, or density of an oil sample is greater than the assumed value for that parameter, then use the actual sampled value for sulfur content, gross calorific value, or

density of fuel to calculate SO₂ mass emission rate or heat input rate as the new assumed sulfur content, gross calorific value, or density. Continue to use this new assumed value to calculate SO₂ mass emission rate or heat input rate unless and until: (1) it is superseded by a higher value from an oil sample; (2) a new contract with a higher maximum sulfur content, gross calorific value, or density is adopted, in which case the new contract value becomes the assumed value; or (3) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

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2.2.6 Where the flowmeter records volumetric flow rate rather than mass flow rate, analyze oil samples to determine the density or specific gravity of the oil.

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

2.3 SO₂ Emissions from Combustion of Gaseous Fuels

Account for the hourly SO₂ mass emissions due to combustion of gaseous fuels for each day when gaseous fuels are combusted by the unit using the procedures in either section 2.3.1 or 2.3.2. The procedures in section 2.3.1 may be used for accounting for SO₂ mass emissions from any gaseous fuel with a total sulfur content ≤20.0 gr/100 scf. The procedures in section 2.3.2 may be used for pipeline natural gas or for any gaseous fuel for which the designated representative demonstrates to the satisfaction of the Administrator, in a petition to the Administrator under § 75.66(i), that the fuel has an SO₂ emission rate no greater than 0.0006 lb/mmBtu. Values used for calculations of SO₂ mass emission rates are summarized in Table D-6, below.

TABLE D-6.—GAS SAMPLING METHODS AND SULFUR AND HEAT CONTENT (GCV) VALUES USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations
Gas Sulfur Content	Gaseous fuel in lots—as-delivered sampling ¹	Highest of all sampled values in previous calendar year OR maximum value allowed by contract ¹
	Any gaseous fuel—daily sampling ²	Highest sulfur in previous 30 daily samples.
	Any gaseous fuel—continuous sampling (at least hourly) with a gas chromatograph.	Actual measured hourly average sulfur content.
Gas GCV/heat content	Gaseous fuel in lots—as-delivered sampling ¹	Highest of all sampled values in previous calendar year OR maximum value allowed by contract. ¹
	Gaseous fuels other than pipeline natural gas that are sampled for sulfur content—daily sampling.	Highest GCV in previous 30 daily samples.
	Gaseous fuels other than pipeline natural gas that are sampled for sulfur content—continuous sampling (at least hourly).	Actual measured hourly average GCV or highest GCV in previous 30 unit operating days.
	Pipeline natural gas—monthly sampling for GCV only.	Actual measured GCV OR highest of all sampled values in previous calendar year OR maximum value allowed by contract. ³

¹ Assumed sulfur and GCV values may only continue to be used if sulfur content and gross calorific value of each as-delivered sample is no greater than the assumed value used to calculate emissions or heat input.

²Continuous sampling (at least hourly) may be required if the sulfur content exhibits too much variability (see section 2.3.3.4, below).

³Assumed GCV values of the highest sampled value in the previous calendar year or the maximum value allowed by contract may only continue to be used if gross calorific value of each monthly sample is no greater than the assumed value used to calculate heat input.

2.3.1 For gaseous fuels received in shipments or lots, sample each shipment or lot of fuel. A fuel lot for gaseous fuel is the volume of product gas from one source (supplier or pretreatment facility), intended as one shipment or delivery, which meets the fuel purchase specifications for sulfur content and GCV. For gaseous fuels, other than pipeline natural gas, that are not delivered in discrete lots or shipments, sample the gaseous fuel at least daily. Continuous sampling (at least hourly) with a gas chromatograph may be required if the sulfur content exhibits too much variability (see section 2.3.3.4, below). For gaseous fuel meeting the definition of pipeline natural gas in § 72.2 of this chapter, either use the procedures of section 2.3.2 of this appendix or sample the gaseous fuel at least daily. Sampling may be performed by either the owner or operator or by the fuel supplier.

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2.3.1.3 Determine the heat content or gross calorific value for a sample using the procedures of section 5.5 of appendix F to this part to determine the heat input rate for each hour the unit combusted gaseous fuel. Calculate heat input using the appropriate GCV from sections 2.3.1.4.1 through 2.3.1.4.3 of this appendix.

2.3.1.4 Calculate the hourly SO₂ mass emission rate, in lb/hr, using Equation D-4 of this appendix. Multiply the hourly metered volumetric flow rate of gas combusted (in 100 scfh) by the appropriate sulfur content from sections 2.3.1.4.1 through 2.3.1.4.2 of this appendix.

2.3.1.4.1 For gaseous fuels received in shipments or lots, use one of the following values: (1) the highest sulfur content and GCV from all shipments in the previous calendar year or (2) the maximum sulfur content and maximum GCV values established by agreement with the fuel supplier through a contract. Continue to use this assumed value until and unless the actual sampled sulfur content or gross calorific value of a delivery exceeds the previously reported assumed value.

If the actual sampled sulfur content or gross calorific value of a gas sample is greater than the assumed value for that parameter, then use the actual sampled value for sulfur content or gross calorific value of gas to calculate SO₂ mass emission rate or heat input rate as the new assumed sulfur content or gross calorific value. Continue to use this sampled value to calculate SO₂ mass emission rate or heat input rate until: (1) it is superseded by a new, higher value from a gas sample; (2) a new contract with a higher maximum sulfur content or gross calorific value is adopted, in which case the new contract value becomes the new assumed value; or (3) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.3.1.4.2 For gaseous fuels other than pipeline natural gas that are not received in shipments or lots that are transmitted by

pipeline and sampled daily, use the highest sulfur content and GCV from the previous 30 daily gas samples. When continuous gas sampling (at least hourly) is required, use the actual measured hourly average sulfur content for each hour that the gaseous fuel is combusted.

2.3.1.4.3 For pipeline natural gas, use the highest sulfur content in the previous 30 daily gas samples, and the GCV from: (1) one or more samples taken during the most recent month when the unit burned gas for at least 48 hours; (2) the highest GCV from all samples in the previous calendar year; or (3) the maximum GCV values established by agreement with the fuel supplier through a contract. Continue to use this assumed value unless and until the actual sampled sulfur content or gross calorific value of a delivery exceeds the previously reported assumed value.

If the actual sampled sulfur content or gross calorific value of a gas sample is greater than the assumed value for that parameter, use the actual sampled value for sulfur content or gross calorific value of gas to calculate SO₂ mass emission rate or heat input rate as the new assumed sulfur content or gross calorific value. Continue to use this sampled value to calculate SO₂ mass emission rate or heat input rate until: (1) it is superseded by a new, higher value from a gas sample; (2) a new contract with a higher maximum sulfur content or gross calorific value is adopted, in which case the new contract value becomes the new assumed value; or (3) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.3.2 If the fuel is pipeline natural gas, as defined in § 72.2 of this chapter, calculate SO₂ emissions under this section using a default SO₂ emission rate of 0.0006 lb/mmBtu.

2.3.2.1 Use the default SO₂ emission rate of 0.0006 lb/mmBtu and the hourly heat input rate from pipeline natural gas in mmBtu/hr, as determined using the procedures in section 5.5 of appendix F to this part. Calculate SO₂ mass emission rate using Equation D-5 of this appendix. Determine the heat content or gross calorific value for at least one sample each month that the gaseous fuel is combusted using the procedures in section 5.5 of appendix F to this part.

2.3.2.2 The procedures in this section 2.3.2 may also be used for a gaseous fuel other than pipeline natural gas if the Administrator approves a petition under § 75.66(i) in which the designated representative demonstrates that the gaseous fuel combusted at the unit has an SO₂ emission rate no greater than 0.0006 lb/mmBtu. To demonstrate this, the petition shall include at least 720 hours of fuel sampling data, indicating the total sulfur content and GCV of the fuel for each hour. Each hourly value of the total sulfur content in the gas or blend (in gr/100 scf) shall be converted to a "fuel sulfur-to-heating value

ratio," by dividing the total sulfur content by the gross calorific value of the fuel (in Btu/100 scf) and then multiplying by a conversion factor of 10⁶ Btu/mmBtu. The mean value of the fuel sulfur-to-heating value ratios shall then be calculated. If the mean value of the ratios does not exceed 2.0 grains of sulfur per mmBtu, then the default SO₂ emission rate of 0.0006 lb/mmBtu may be used to account for SO₂ mass emissions under this part, whenever the gaseous fuel is combusted.

2.3.3 For all types of gaseous fuels, the owner or operator shall provide, in the monitoring plan for the unit, historical fuel sampling information on the sulfur content of the gaseous fuel sufficient to demonstrate that use of this appendix is applicable because the gas has a total sulfur content of 20.0 grain/100 scf or less. Provide this information with the initial monitoring plan for the unit and following any significant changes in gas contract or source of supply. However, for units combusting pipeline natural gas that have gas flowmeters certified prior to the effective date of this rule, this information may be retained on site in a form suitable for inspection, rather than submitted as an update to the monitoring plan. In addition, provide the following specific information in the monitoring plan required under § 75.53, depending on the type of gaseous fuel:

2.3.3.1 For pipeline natural gas, provide information demonstrating that the definition of pipeline natural gas in § 72.2 of this chapter has been met. This demonstration must be made using one of the following sources of information: (1) the gas quality characteristics specified by a purchase contract or by a pipeline transportation contract; (2) a certification of the gas vendor, based on routine vendor sampling and analysis; or (3) at least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently.

2.3.3.2 For gaseous fuel other than pipeline natural gas for which a petition has been submitted and approved under section 2.3.2.2 of this appendix, provide the information required to be included in the petition pursuant to section 2.3.2.2.

2.3.3.3 For liquefied petroleum gas and other gaseous fuels provided in batches or lots having uniform sulfur content, provide either contractual information from the fuel supplier or provide historical information on each lot of liquefied petroleum gas from at least one year.

2.3.3.4 For any other gaseous fuel or blend, including gas produced by a variable process (e.g., digester gas or landfill gas), provide data on the fuel sulfur content, as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content of the gas or blend (in gr/100 scf). The data shall be obtained with a gas chromatograph, and, for gaseous fuel produced by a variable process, the data shall be representative of all process operating conditions. The data shall be reduced to hourly averages and shall be

used to determine whether daily sampling of the sulfur content of the gas or blend is sufficient or whether sampling, at least hourly, with a gas chromatograph is required. Specifically, daily gas sampling shall be sufficient, provided that either: (1) the mean value of the total sulfur content of the gas or blend is ≤7 grains per 100 scf; or (2) the standard deviation of the hourly average values from the mean does not exceed 5 grains per 100 scf. If the gas or blend does not meet requirement (1) or (2), then

sampling, at least hourly, of the fuel with a gas chromatograph (GCH) and hourly reporting of the hourly average sulfur content of the fuel is required. If sampling, at least hourly, from a gas chromatograph is required, the owner or operator shall develop and implement a program to quality assure the data from the GCH, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.4.1 Missing Data for Oil and Gas Samples

When oil sulfur content, density, or gross calorific value data are missing or invalid for an oil or gas sample taken according to the procedures in section 2.2.3, 2.2.4.1, 2.2.4.2, 2.2.4.3, 2.3.1, 2.3.1.1, 2.3.1.2, or 2.3.1.3 of this appendix, then substitute the maximum potential sulfur content, density, or gross calorific value of that fuel from Table D-7 of this appendix.

TABLE D-7.—MISSING DATA SUBSTITUTION PROCEDURES FOR SULFUR, DENSITY, AND GROSS CALORIFIC VALUE

Parameter	Missing data substitution maximum potential value
Oil Sulfur Content	3.5 percent for residual oil, or, 1.0 percent for diesel fuel.
Oil Density	8.5 lb/gal for residual oil, or 7.4 lb/gal for diesel fuel.
Oil GCV	19,500 Btu/lb for residual oil, or 20,000 Btu/lb for diesel fuel.
Gas Sulfur Content	0.30 gr/100 scf for pipeline natural gas, or 20.0 gr/100 scf for other gaseous fuel.
Gas GCV/Heat Content	1100 Btu/scf for pipeline natural gas, or 2100 Btu/scf for other gaseous fuel.

2.4.2 Whenever data are missing from any fuel flowmeter that is part of an excepted monitoring system under appendix D or E to this part, where the fuel flowmeter data are required to determine the amount of fuel combusted by the unit, use the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix to account for the flow rate of fuel combusted at the unit for each hour during the missing data period. In addition, a fuel flowmeter used for measuring fuel combusted by a peaking unit may use the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix.

2.4.2.1 Simplified Fuel Flow Missing Data for Peaking Units.

If no fuel flow rate data are available for a fuel flowmeter system installed on a peaking unit (as defined in § 72.2 of this chapter), then substitute for each hour of missing data using the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following: (1) the maximum fuel flow rate the unit is capable of combusting or (2) the maximum flow rate that the flowmeter can measure (i.e., upper range value of flowmeter leading to a unit).

2.4.2.2 * * *

2.4.2.3 For hours where two or more fuels are combusted, substitute the maximum hourly fuel flow rate measured and recorded by the flowmeter (or flowmeters, where fuel is recirculated) for the fuel for which data are missing at the corresponding load range recorded for each missing hour during the previous 720 hours when the unit combusted that fuel with any other fuel. For hours where no previous recorded fuel flow rate data are available for that fuel during the missing data period, calculate and substitute the maximum potential flow rate of that fuel for the unit as defined in section 2.4.2.2 of this appendix.

2.4.3 * * *

65. Section 3 of appendix D to part 75 is amended by:

- a. Revising sections 3, 3.1, 3.2, 3.2.1, 3.2.3, 3.2.4, and 3.3;

- b. Redesignating section 3.4 as section 3.5 and revising the introductory text; and

- c. Adding a new section 3.4, to read as follows:

3. Calculations

Use the calculation procedures in section 3.1 of this appendix to calculate SO₂ mass emission rate. Where an oil flowmeter records volumetric flow rate, use the calculation procedures in section 3.2 of this appendix to calculate the mass flow rate of oil. Calculate hourly SO₂ mass emission rate from gaseous fuel using the procedures in section 3.3 of this appendix. Calculate hourly heat input rate for oil and for gaseous fuel using the equations in section 5.5 of appendix F to this part. Calculate total SO₂ mass emissions and heat input as provided under section 3.4 of this appendix.

3.1 SO₂ Mass Emission Rate Calculation for Oil

3.1.1 Use the following equation to calculate SO₂ mass emissions per hour (lb/hr):

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

(Eq. D-2)

where:

M_{SO₂} = Hourly mass emission rate of SO₂ emitted from combustion of oil, lb/hr.

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

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

2.0 = Ratio of lb SO₂/lb S.

3.1.2 Record the SO₂ mass emission rate from oil for each hour that oil is combusted.

3.2 Mass Flow Rate Calculation for Oil Using Volumetric Flow Rate

3.2.1 Where the oil flowmeter records volumetric flow rate rather than mass flow rate, calculate and record the oil mass flow rate for each hourly period using hourly oil

flow rate measurements and the density or specific gravity of the oil sample.

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

$$M_{oil} = V_{oil} \times D_{oil}$$

(Eq. D-3)

Where:

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

V_{oil} = Volume rate of oil consumed per hr, measured in scf, gal, barrels, or m³.

D_{oil} = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m³.

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

3.3 SO₂ Mass Emissions Rate Calculation for Gaseous Fuels

3.3.1 Use the following equation to calculate the SO₂ emission rate using the gas sampling and analysis procedures in section 2.3.1 of this appendix:

$$M_{(SO_2)_g} = \left(\frac{2.0}{7000} \right) \times Q_g \times S_g$$

(Eq. D-4)

Where:

M_{(SO₂)_g} = Hourly mass rate of SO₂ emitted due to combustion of gaseous fuel, lb/hr.

Q_g = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.

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

2.0 = Ratio of lb SO₂/lb S.

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

3.3.2 Use the following equation to calculate the SO₂ emission rate using the

0.0006 lb/mmBtu emission rate in section 2.3.2 of this appendix:

$$M_{(SO_2)_g} = ER \times HI_g$$

(Eq. D-5)

Where:

$M_{(SO_2)_g}$ = Hourly mass rate of SO₂ emissions from combustion of pipeline natural gas, lb/hr.

ER = SO₂ emission rate of 0.0006 lb/mmBtu for pipeline natural gas.

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

3.3.3 Record the SO₂ mass emission rate for each hour when the unit combusts gaseous fuel.

3.4 Conversion of Rates to Totals and Summation of Quarterly and Cumulative Values

3.4.1 SO₂ Mass Emissions Conversions and Summations.

For a unit or for a common pipe, calculate total quarterly SO₂ mass emissions (using Equation D-6) and total cumulative SO₂ mass emissions (using Equation D-7). First convert hourly SO₂ mass emission rates for each fuel

to total hourly SO₂ mass emissions, by multiplying the hourly rates by the fuel usage time. Second, sum the total hourly SO₂ mass emissions from all fuels for the quarter. Third, convert the quarterly SO₂ mass emission total to tons. Finally, for cumulative emissions, sum the quarterly SO₂ mass emission totals, in tons, for each quarter in the year to date.

$$SO_{2q} = \frac{1}{2000} \sum_{\text{first fuel}}^{\text{last fuel}} \sum_{\text{hour}=1}^n \sum_{\text{first system}}^{\text{last system}} SO_{2i \text{ fuel system}} t_i$$

(Eq. D-6)

Where:

SO_{2q} = Total SO₂ mass emissions for the quarter, tons.

SO_{2i fuel system} = SO₂ mass emission rate for a given fuel for a particular fuel flow system, lb/hr.

t_i = Fuel usage time for the fuel and system, hour or fraction of an hour.

$$SO_{2c} = \sum_{q=1}^{\text{the current quarter}} SO_{2q}$$

(Eq. D-7)

Where:

SO_{2c} = Total SO₂ mass emissions for the year to date, tons.

SO_{2q} = Total SO₂ mass emissions for the quarter, tons.

3.4.2 Heat Input Conversions and Summations

Calculate total quarterly (using Equation D-8) and total cumulative (using Equation D-9) heat input for a unit or common pipe with fuel flow systems.

$$HI_q = \sum_{\text{first fuel}}^{\text{last fuel}} \sum_{\text{hour}=1}^n \sum_{\text{first system}}^{\text{last system}} HI_{i \text{ fuel system}} t_i$$

(Eq. D-8)

Where:

HI_q = Total heat input for the quarter, mmBtu.

HI_{i fuel system} = Heat input rate during fuel usage for a given fuel for a particular fuel flow system, using Equation F-19 or F-20, mmBtu/hr.

t_i = Fuel usage time for the fuel and system, hour or fraction of an hour.

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q$$

(Eq. D-9)

Where:

HI_c = Total heat input for the year to date, mmBtu.

HI_q = Total heat input for the quarter, mmBtu.

3.5 Records and Reports

Calculate and record quarterly and cumulative SO₂ mass emissions and heat input for each calendar quarter using the procedures and equations of section 3.4 of this appendix.

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APPENDIX E TO PART 75—OPTIONAL NO_x EMISSIONS ESTIMATION PROTOCOL FOR GAS-FIRED PEAKING UNITS AND OIL-FIRED PEAKING UNITS

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66. Section 2 of appendix E to part 75 is amended by revising sections 2.5.4 and 2.5.5 to read as follows:

2. Procedure

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2.5 Missing Data Procedures

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2.5.4 Substitute missing data from a fuel flowmeter using the procedures in section 2.4.2 of appendix D to this part.

2.5.5 Substitute missing data for gross calorific value of fuel using the procedures in sections 2.4.1 of appendix D to this part.

67. Section 3 of Appendix E to part 75 is amended by revising sections 3.1, 3.3.1, and 3.3.4 to read as follows:

3. Calculations

3.1 Heat Input

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

$$HI_T = HI_{\text{fuel } 1} t_1 + HI_{\text{fuel } 2} t_2 + HI_{\text{fuel } 3} t_3 + \dots + HI_{\text{last fuel}} t_{\text{last}}$$

(Eq. E-1)

Where:

H_T = Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.

$HI_{fuel\ 1,2,3,\dots,last}$ = Heat input rate from each fuel, in mmBtu/hr as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr.

$t_{1,2,3,\dots,last}$ = Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

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3.3 * * *

3.3.1 Conversion from Concentration to Emission Rate.

Convert the NO_x concentrations (ppm) and O₂ concentrations to NO_x emission rates (to the nearest 0.01 lb/mmBtu for tests performed prior to January 1, 2000 or to the nearest 0.001 lb/mmBtu for tests performed on and after January 1, 2000), according to the appropriate one of the following equations: F-5 in appendix F to this part for dry basis concentration measurements or 19-3 in Method 19 of appendix A to part 60 of this chapter for wet basis concentration measurements.

* * * * *

3.3.4 Average NO_x Emission Rate During Co-firing of Fuels.

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

(Eq. E-2)

Where:

E_h = NO_x emission rate for the unit for the hour, lb/mmBtu.

E_f = NO_x emission rate for the unit for a given fuel at heat input rate HI_f , lb/mmBtu.

HI_f = Heat input rate for the hour for a given fuel, during the fuel usage time, as determined using Equation F-19 or F-20 in section 5.5 of appendix F to this part, mmBtu/hr

H_T = Total heat input for all fuels for the hour from Equation E-1.

t_f = Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

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

68. Section 2 of appendix F to part 75 is revised to read as follows:

Appendix F to Part 75—Conversion Procedures

* * * * *

2. Procedures for SO₂ Emissions

Use the following procedures to compute hourly SO₂ mass emission rate (in lb/hr) and quarterly and annual SO₂ total mass emissions (in tons). Use the procedures in Method 19 in appendix A to part 60 of this

chapter to compute hourly SO₂ emission rates (in lb/mmBtu) for qualifying Phase I technologies. When computing hourly SO₂ emission rate in lb/mmBtu, a minimum concentration of 5.0 percent CO₂ and a maximum concentration of 14.0 percent O₂ may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO₂ is less than 5.0 percent CO₂ or the hourly average concentration of O₂ is greater than 14.0 percent O₂.

2.1 When measurements of SO₂ concentration and flow rate are on a wet basis, use the following equation to compute hourly SO₂ mass emission rate (in lb/hr):

$$E_h = K C_h Q_h$$

(Eq. F-1)

Where:

E_h = Hourly SO₂ mass emission rate during unit operation, lb/hr.

$K = 1.660 \times 10^{-7}$ for SO₂, (lb/scf)/ppm.

C_h = Hourly average SO₂ concentration during unit operation, stack moisture basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, stack moisture basis, scfh.

2.2 When measurements by the SO₂ 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 SO₂ mass emission rate (in lb/hr):

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

(Eq. F-2)

Where:

E_h = Hourly SO₂ mass emission rate during unit operation, lb/hr.

$K = 1.660 \times 10^{-7}$ for SO₂, (lb/scf)/ppm.

C_{hp} = Hourly average SO₂ concentration during unit operation, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

2.3 Use the following equations to calculate total SO₂ mass emissions for each calendar quarter (Equation F-3) and for each calendar year (Equation F-4), in tons:

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

(Eq. F-3)

Where:

E_q = Quarterly total SO₂ mass emissions, tons.

E_h = Hourly SO₂ mass emission rate, lb/hr.

t_h = Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Number of hourly SO₂ 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 SO₂ mass emissions, tons.

E_q = Quarterly total SO₂ mass emissions, tons.

q = Quarters for which E_q are available during calendar year.

2.4 Round all SO₂ mass emission rates and totals to the nearest tenth.

69. Section 3 of appendix F to part 75 is amended by revising sections 3.3.2, 3.3.3, 3.3.4, 3.4, and 3.5 to read as follows:

3. Procedures for NO_x Emission Rate

* * * * *

3.3 * * *

3.3.2 E = Pollutant emissions during unit operation, lb/mmBtu.

3.3.3 C_h = Hourly average pollutant concentration during unit operation, ppm.

3.3.4 %O₂, %CO₂ = Oxygen or carbon dioxide volume during unit operation (expressed as percent O₂ or CO₂). A minimum concentration of 5.0 percent CO₂ and a maximum concentration of 14.0 percent O₂ may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO₂ is <5.0 percent CO₂ or the hourly average concentration of O₂ is >14.0 percent O₂. A minimum concentration of 1.0 percent CO₂ and a maximum concentration of 19.0 percent O₂ may be substituted for measured diluent gas concentration values at stationary gas turbines during hours when the hourly average concentration of CO₂ is <1.0 percent CO₂ or the hourly average concentration of O₂ is >19.0 percent O₂.

* * * * *

3.4 Use the following equations to calculate the average NO_x emission rate for each calendar quarter (Equation F-9) and the average emission rate for the calendar year (Equation F-10), in lb/mmBtu:

$$E_q = \sum_{i=1}^n \frac{E_i}{n}$$

(Eq. F-9)

Where:

E_q = Quarterly average NO_x emission rate, lb/mmBtu.

E_i = Hourly average NO_x emission rate during unit operation, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^m \frac{E_i}{m}$$

(Eq. F-10)

Where:

E_a = Average NO_x emission rate for the calendar year, lb/mmBtu.

E_i = Hourly average NO_x emission rate during unit operation, lb/mmBtu.
 m = Number of hourly rates for which E_i is available in the calendar year.

3.5 Round all NO_x emission rates to the nearest 0.01 lb/mmBtu prior to January 1, 2000 and to the nearest 0.001 lb/mmBtu on and after January 1, 2000.

70. Section 4 of appendix F to part 75 is amended by revising sections 4.1, 4.2, 4.3, and 4.4.1 to read as follows:

4. Procedures for CO_2 Mass Emissions

* * * * *

4.1 When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr):

$$E_h = K C_h Q_h$$

(Eq. F-11)

Where:

E_h = Hourly CO_2 mass emission rate during unit operation, tons/hr.
 $K = 5.7 \times 10^{-7}$ for CO_2 , (tons/scf) / % CO_2 .
 C_h = Hourly average CO_2 concentration during unit operation, wet basis, percent CO_2 . For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2 , provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2 , provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of heat input for that hour.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

4.2 When CO_2 concentration is measured on a dry basis, use Equation F-2 to calculate the hourly CO_2 mass emission rate (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf) percent CO_2 , where E_h = hourly CO_2 mass emission rate, tons/hr and C_{hp} = hourly average CO_2 concentration in flue, dry basis, percent CO_2 .

4.3 Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation F-12) and for each calendar year (Equation F-13):

$$E_{CO_2q} = \sum_{h=1}^{H_R} E_h t_h$$

(Eq. F-12)

Where:

$E_{(CO_2)q}$ = Quarterly total CO_2 mass emissions, tons.
 E_h = Hourly CO_2 mass emission rate, tons/hr.
 t_h = Unit operating time, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
 H_R = Number of hourly CO_2 mass emission rates available during calendar quarter.

* * * * *

4.4 * * *
 4.4.1 Use appropriate F and F_c factors from section 3.3.5 of this appendix in the following equation to determine hourly average CO_2 concentration of flue gases (in percent by volume):

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

or
 (Eq. F-14b)

Where:

CO_{2w} = Hourly average CO_2 concentration during unit operation, percent by volume, wet basis.

O_{2w} = Hourly average O_2 concentration during unit operation, percent by volume, wet basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2 , provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2 , provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of heat input for that hour.

F, F_c = F-factor or carbon-based F_c -factor from section 3.3.5 of this appendix.
 20.9 = Percentage of O_2 in ambient air.

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

(Eq. F-14a)

Where:

CO_{2d} = Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.
 F, F_c = F-factor or carbon-based F_c -factor from section 3.3.5 of this appendix.
 20.9 = Percentage of O_2 in ambient air.
 O_{2d} = Hourly average O_2 concentration during unit operation, percent by volume, dry basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2 , provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2 , provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of heat input for that hour.

% H_2O = Moisture content of gas in the stack, percent.

* * * * *

71. Section 5 of appendix F to part 75 is amended by revising sections 5, 5.1, 5.2, 5.5, 5.5.1, and 5.5.2 and by adding new sections 5.3, 5.6, and 5.7 to read as follows:

5. Procedures for Heat Input

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

5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided below. The owner or operator may choose to use the provisions specified in § 75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided below to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O₂ or CO₂) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

5.2.1 When measurements of CO₂ concentration are on a wet basis, use the following equation:

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

(Eq. F-15)

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

%CO_{2w} = Hourly concentration of CO₂ during unit operation, percent CO₂ wet basis. For boilers, a minimum concentration of 5.0 percent CO₂ may be substituted for the measured concentration when the hourly average concentration of CO₂ is < 5.0 percent CO₂, provided that this minimum concentration of 5.0 percent CO₂ is also used in the calculation of CO₂ mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO₂ is < 1.0 percent CO₂, provided that this minimum concentration of 1.0 percent CO₂ is also used in the calculation of CO₂ mass emissions for that hour.

5.2.2 When measurements of CO₂ 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 rate during unit operation, mmBtu/hr.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-Factor, listed above in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

%CO_{2d} = Hourly concentration of CO₂ during unit operation, percent CO₂ dry basis. For boilers, a minimum concentration of 5.0 percent CO₂ may be substituted for the measured concentration when the hourly average concentration of CO₂ is < 5.0 percent CO₂, provided that this minimum concentration of 5.0 percent CO₂ is also used in the calculation of CO₂ mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO₂ is < 1.0 percent CO₂, provided that this minimum concentration of 1.0 percent CO₂ is also used in the calculation of CO₂ mass emissions for that hour.

%H₂O = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O₂ 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 rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

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

%O_{2w} = Hourly concentration of O₂ during unit operation, percent O₂ wet basis. For boilers, a maximum concentration of 14.0 percent O₂ may be substituted for the measured concentration when the hourly average concentration of O₂ is > 14.0 percent O₂, provided that this maximum concentration of 14.0 percent O₂ is also used in the calculation of CO₂ mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O₂ is > 19.0 percent O₂, provided that this maximum concentration of 19.0 percent O₂ is also used in the calculation of CO₂ mass emissions for that hour.

%H₂O = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O₂ concentration are on a dry basis, use the following equation:

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

(Eq. F-18)

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow during unit operation, wet basis, scfh.

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

%H₂O = Moisture content of the stack gas, percent.

%O_{2d} = Hourly concentration of O₂ during unit operation, percent O₂ dry basis. For boilers, a maximum concentration of 14.0 percent O₂ may be substituted for the measured concentration when the hourly average concentration of O₂ is > 14.0 percent O₂, provided that this maximum concentration of 14.0 percent O₂ is also used in the calculation of CO₂ mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O₂ may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O₂ is > 19.0 percent O₂, provided that this maximum concentration of 19.0 percent O₂ is also used in the calculation of CO₂ mass emissions for that hour.

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{\text{hour}=1}^n HI_i t_i$$

(Eq. F-18a)

Where:

HI_q = Total heat input for the quarter, mmBtu.

HI_i = Hourly heat input rate during unit operation, using Equation F-15, F-16, F-17, or F-18, mmBtu/hr.

t_i = Hourly operating time for the unit or common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q$$

(Eq. F-18b)

Where:

HI_c = Total heat input for the year to date, mmBtu.

HI_q = Total heat input for the quarter, mmBtu.

5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO₂ emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_x mass emissions under a state or federal NO_x mass emission reduction program.

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

$$HI_o = M_o \frac{GCV_o}{10^6}$$

(Eq. F-19)

Where:

HI_o = Hourly heat input rate from oil, mmBtu/hr.

M_o = Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o = Gross calorific value of oil, as measured by ASTM D240-87 (Reapproved 1991), ASTM D2015-91, or ASTM D2382-88 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (incorporated by reference under § 75.6).

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

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

$$HI_g = \frac{(Q_g \times GCV_g)}{10^6}$$

(Eq. F-20)

Where:

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

Q_g = Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet.

GCV_g = Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a GCH, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 "Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis," or GPA Standard 2261-90 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," Btu/100 scf (incorporated by reference under § 75.6).

10⁶ = Conversion of Btu to mmBtu.

* * * * *

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts should apportion the heat input rate using the following equation:

$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{MW_i t_i}{\sum_{i=1}^n MW_i t_i} \right]$$

(Eq. F-21a)

Where:

HI_i = Heat input rate for a unit, mmBtu/hr.

HI_{CS} = Heat input rate at the common stack or pipe; mmBtu/hr.

MW_i = Gross electrical output, MWe.

t_i = Operating time at a particular unit, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS} = Operating time at common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack.

i = Designation of a particular unit.

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load should apportion the heat input rate using the following equation:

$$HI_i = HI_{CS} \left(\frac{t_{CS}}{t_i} \right) \left[\frac{SF_i t_i}{\sum_{i=1}^n SF_i t_i} \right]$$

(Eq. F-21b)

Where:

- HI_i=Heat input rate for a unit, mmBtu/hr.
- HI_{CS}=Heat input rate at the common stack or pipe, mmBtu/hr.
- SF=Gross steam load, lb/hr.
- t_i=Operating time at a particular unit, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
- t_{CS}=Operating time at common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
- n=Total number of units using the common stack.
- i=Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes should sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^n HI_s t_s}{t_{Unit}}$$

(Eq. F-21c)

Where:

- HI_{Unit}=Heat input rate for a unit, mmBtu/hr.
- HI_s=Heat input rate for each stack or duct leading from the unit, mmBtu/hr.
- t_{Unit}=Operating time for the unit, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
- t_s=Operating time during which the unit is exhausting through the stack or duct, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

72. Section 8 of appendix F to part 75 is added to read as follows:

8. Procedures for NO_x Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_x mass emissions under a state or federal NO_x mass emission reduction program must use the procedures in section 8.1 to account for hourly NO_x mass emissions, and the procedures in section 8.2 to account for quarterly, seasonal, and annual NO_x mass emissions if the provisions of subpart H of

this part are adopted as requirements under such a program.

8.1 Use the following procedures to calculate hourly NO_x mass emissions in lbs for the hour.

8.1.1 If both NO_x emission rate and heat input are monitored at the same unit or stack level (e.g. the NO_x emission rate value and heat input value both represent all of the units exhausting to the common stack), use the following equation:

$$M_{NO_x, h} = E_h HI_h t_h$$

(Eq. F-23)

Where:

- M_{NO_x(h)}=NO_x mass emissions in lbs for the hour.
- E_h=Hourly average NO_x emission rate for hour h, lb/mmBtu.
- HI_h=Hourly average heat input rate for hour h, mmBtu/hr.
- t_h=Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_x emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.1.2 If NO_x emission rate is measured at a common stack and heat input is measured at the unit level, sum the hourly heat inputs at the unit level according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^p HI_u t_u}{t_{CS}}$$

(Eq. F-24)

Where:

- HI_{CS}=Hourly average heat input rate for hour h for the units at the common stack, mmBtu/hr.
- t_{CS}=Common stack operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator) (e.g., total time when any of the units which exhaust through the common stack are operating).

HI_u=Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u=Unit operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). Use the hourly heat input rate at the common stack level and the hourly average NO_x emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_x mass emissions at the common stack.

8.1.3 If a unit has multiple ducts and NO_x emission rate is only measured at one duct, use the NO_x emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_x mass emissions.

8.1.4 If a unit has multiple ducts and NO_x emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_x mass emissions.

8.2 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_x mass emissions, in tons:

$$M_{(NO_x)_{time\ period}} = \frac{\sum_{h=1}^p M_{(NO_x)_h}}{2000}$$

(Eq. F-25)

Where:

M_{(NO_x)_{time period}}=NO_x mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

M_{(NO_x)_h}=NO_x mass emissions in lbs for the hour.

p=The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

8.3 *Specific provisions for monitoring NO_x mass emissions from common stacks.* The owner or operator of a unit utilizing a common stack may account for NO_x mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a state or federal NO_x mass reduction program:

8.3.1 The owner or operator may determine both NO_x emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_x mass emissions.

8.3.2 The owner or operator may determine the NO_x emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_x mass emissions.

APPENDIX G TO PART 75— DETERMINATION OF CO₂ EMISSIONS

* * * * *

73. Section 2 of appendix G to part 75 is amended by revising the term "Wc" that follows Equation G-1 to read as follows:

2. Procedures for Estimating CO₂ Emissions From Combustion

2.1 * * *

(Eq. G-1)

Where:

* * * * *

W_C=Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates. Collect at least one fuel sample during each week that the unit combusts coal, one sample per each shipment for oil and diesel fuel, and one fuel sample for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, or for each monthly sample of pipeline natural gas. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week. Determine the carbon content of each fuel sampling using one of the following methods: ASTM D3178-89 or ASTM D5373-93 for coal; ASTM D5291-92 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil, or computations based upon ASTM D3238-90 and either ASTM D2502-87 or ASTM D2503-82 (Reapproved 1987) for oil; and computations based on ASTM D1945-91 or ASTM D1946-90 for gas. Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. (All ASTM methods are incorporated by reference under § 75.6). Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

* * * * *

74. Appendix G to part 75 is amended by adding a new section 5 and Table G-1 to read as follows:

5. Missing Data Substitution Procedures for Fuel Analytical Data

Use the following procedures to substitute for missing fuel analytical data used to calculate CO₂ mass emissions under this appendix.

5.1 Missing Carbon Content Data Prior to 1/1/2000

Prior to January 1, 2000, follow either the procedures of this section or the procedures of section 5.2 of this appendix to substitute for missing carbon content data. On and after January 1, 2000, use the procedures of section 5.2 of this appendix to substitute for missing carbon content data, not the procedures of this section.

5.1.1 Most Recent Previous Data

Substitute the most recent, previous carbon content value available for that fuel type (gas, oil, or coal) of the same grade (for oil) or rank (for coal). To the extent practicable, use a carbon content value from the same fuel supply. Where no previous carbon content data are available for a particular fuel type or rank of coal, substitute the default carbon content from Table G-1 below.

5.1.2 [Reserved]

5.2 Missing Carbon Content Data on and After 1/1/2000

Prior to January 1, 2000, follow either the procedures of this section or the procedures of section 5.1 of this appendix to substitute for missing carbon content data. On and after January 1, 2000, use the procedures of this section to substitute for missing carbon content data.

5.2.1 Missing Weekly Samples

If carbon content data are missing for weekly coal samples or composite oil samples from continuous sampling, substitute the highest carbon content from the previous four carbon samples available. If no previous carbon content data are available, use the default carbon content from Table G-1, below.

5.2.2 Manual Sample From Storage Tank

If carbon content data are missing for manual oil or diesel fuel samples taken from the storage tank after transfer of a new delivery of fuel, substitute the highest carbon content from all samples in the previous calendar year. If no previous carbon content data are available from the previous calendar year, use the default carbon content from Table G-1, below.

5.2.3 As-Delivered Sample

If carbon content data are missing for as-delivered samples of oil, diesel fuel, or gaseous fuel delivered in lots, substitute the highest carbon content from all deliveries of that fuel in the previous calendar year. If no previous carbon content data are available for that fuel from the previous calendar year, use the default carbon content from Table G-1, below.

5.2.4 Sample of Gaseous Fuel Supplied by Pipeline

If carbon content data are missing for a gaseous fuel that is supplied by a pipeline and sampled on either a monthly or a daily basis for sulfur and gross calorific value, substitute the highest carbon content available for that fuel from the previous calendar year. If no previous carbon content data are available for that fuel from the previous calendar year, use the default carbon content from Table G-1, below.

TABLE G-1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Sampling technique/frequency	Missing data substitution procedure
Oil and coal carbon content	All oil and coal samples, prior to January 1, 2000	Most recent, previous carbon content value available for that grade of oil.
	Weekly coal sample or Flow proportional/weekly composite oil sample (beginning no later than January 1, 2000).	Highest carbon in previous 4 weekly samples.
	In storage tank (after addition of fuel to tank) (beginning no later than January 1, 2000).	Maximum carbon content from all samples in previous calendar year.
Gas carbon content	As delivered (in delivery truck or barge) (beginning no later than January 1, 2000).	Maximum carbon content from all deliveries in previous calendar year.
	All gaseous fuel samples, prior to January 1, 2000	Most recent, previous carbon content value available for that type of gaseous fuel.
	Gaseous fuel in lots—as-delivered sampling (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
Default coal carbon content	Gaseous fuel delivered by pipeline that is sampled for sulfur content—daily sampling (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
	Pipeline natural gas that is not sampled for sulfur content—monthly sampling for GCV and carbon only (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
	All	Anthracite: 90.0 percent. Bituminous: 85.0 percent. Subbituminous/Lignite: 75.0 percent.
Default oil carbon content	All	90.0 percent.

TABLE G-1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA—Continued

Parameter	Sampling technique/frequency	Missing data substitution procedure
Default gas carbon content ..	All	Natural gas: 75.0 percent. Other gaseous fuels: 90.0 percent.

5.3 Gross Calorific Value Data

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO₂ emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of appendix D to this part.

Appendix H To Part 75—Revised Traceability Protocol No. 1

75. Appendix H to part 75 is removed and reserved.

76. Appendix I to part 75 is added as follows:

Appendix I To Part 75—Optional F-Factor/Fuel Flow Method

1. Applicability

1.1 This procedure may be used in lieu of continuous flow monitors for the purpose of determining volumetric flow from gas-fired units, as defined in § 72.2 of this chapter, or oil-fired units, as defined in § 72.2 of this chapter, provided that the units burn only pipeline natural gas, natural gas, and/or fuel oil. These procedures use fuel flow measurement, fuel sampling data, CO₂ (or O₂) CEMS data, and F-factors to determine the flow rate of the stack gas. These procedures may only be used during those hours when only one type of fuel is combusted.

1.2 Apply to the Administrator, in a certification application, for approval to use this method in lieu of a continuous flow monitor, no later than the deadlines for the certification of continuous emission monitoring systems specified in §§ 75.20 and 75.63.

2. Procedure

2.1 Initial Certification and Recertification Testing

Either of the following procedures may be used to perform initial certification and recertification testing of the appendix I excepted flow monitoring system:

2.1.1 Component-by-Component Certification Testing

Test both the fuel flowmeter component and the CO₂ (or O₂) monitor component separately, following the procedures of this part. Determine BAF_{System} and BAF_{CO2} or BAF_{O2}, using the procedures in section 3.7 of this appendix.

2.1.1.1 Certification of the Fuel Flowmeter

Test the fuel flowmeter according to the procedures and performance specifications in section 2.1.5 of appendix D to this part.

2.1.1.2 Certification of the CO₂ (or O₂) Monitor

Test the CO₂ or O₂ monitor according to the procedures and performance specifications in appendix A to this part. Notwithstanding the requirements of appendix A to this part, calculate the BAF of the CO₂ or O₂ monitor according to section 3.7 of this appendix.

2.1.2 System Certification Testing

Test the entire appendix I flow monitoring system to meet the relative accuracy requirements for flow, as found in section 3.3.4 of appendix A to this part, using the applicable procedures in sections 6.5 through 6.5.2.2 of appendix A to this part. Use the fuel sampling data for density and carbon content to calculate the hourly volumetric flow rate according to section 2.3 of this appendix. Perform the bias test and, if necessary, calculate a bias adjustment factor for the appendix I flow monitoring system using the procedures in section 7.6 of appendix A to this part. Also perform the 7-day calibration error test, cycle time test, and linearity check on the CO₂-or O₂-diluent monitor.

2.2 On-Going Quality Assurance Testing

2.2.1 Daily Assessments

The CO₂ or O₂ monitor shall meet the daily assessment requirements in section 2.1 of appendix B to this part.

2.2.2 Quarterly Assessments

The CO₂ or O₂ monitor shall meet the quarterly assessment requirements in section 2.2 of appendix B to this part.

2.2.3 Semiannual or Annual Assessments

2.2.3.1 Component-by-Component Assessments

Test both the fuel flowmeter and the CO₂ (or O₂) monitor separately. Determine BAF_{System} and BAF_{CO2} or BAF_{O2} using the procedures in section 3.7 of this appendix.

2.2.3.1.1 Assessment of the Fuel Flowmeter

The fuel flowmeter shall meet the periodic quality assurance requirements in section 2.1.6 of appendix D to this part. The fuel flowmeter shall meet the flowmeter accuracy specification in section 2.1.5 of appendix D to this part.

2.2.3.1.2 Relative Accuracy Assessment of the CO₂ (or O₂) Monitor

Test the CO₂ or O₂ monitor for relative accuracy according to the applicable procedures in sections 6.5 through 6.5.2.2 of appendix A to this part. Determine the relative accuracy test frequency (i.e., semiannual or annual) using section 2.3.1 and figure 2 in appendix B to this part. Perform the bias test and calculate any bias adjustment factor, as specified in section

3.7.1 of this appendix for the CO₂ monitor or as specified in section 3.7.2 of this appendix for the O₂ monitor.

2.2.3.2 System Relative Accuracy Assessment

Test the entire appendix I flow monitoring system to meet the relative accuracy requirements for flow, as found in section 3.3.4 of appendix A to this part, using the procedures in section 6.5.2 of appendix A to this part. Use Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to obtain the reference method flow rate value for each run. Use the appropriate equation selected from Eq. I-1 through Eq. I-9 to calculate the Appendix I flow rate value for each RATA run. Base the fuel sampling on section 2.3 of this appendix. Determine the schedule for future relative accuracy tests using the provisions of section 2.3.1 and figure 2 of appendix B to this part for a flow monitoring system. Perform the bias test and, if necessary, calculate a bias adjustment factor for the appendix I flow monitoring system using the procedures in section 7.6 of appendix A to this part.

2.3 Fuel Sampling and Analysis

2.3.1 Carbon Content of Oil

Determine carbon content of the oil by using the following procedures. Collect at least one sample per each shipment for oil and diesel fuel. Determine the carbon content of the fuel sampling using one of the following methods: ASTM D5291-92 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil, or computations based upon ASTM D3238-90 and either ASTM D2502-87 or ASTM D2503-82 (Reapproved 1987) for oil.

2.3.2 Density of Oil

Determine the density of oil using the procedures in section 2.2 of appendix D to this part.

2.3.3 Gross Calorific Value of Natural Gas

Determine gross calorific value of natural gas by using the procedures in section 5.5.2 of appendix F to this part.

3. Calculations

3.1 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use a CO₂ Monitor and a Volumetric Oil Flowmeter

$$Q_s = \frac{32.08 \times V \times \rho \times \%C}{\%CO_2}$$

(Eq. I-1)

Where:

Q_s =Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system} =Bias adjustment factor for the system, as determined by Equation I-10A or I-10B (for component-by-component testing) in section 3.7 of this appendix or by Equation I-11 (for system testing) in section 3.8 of this appendix.

V =Volumetric oil flow rate, gal/hr.

ρ =Oil density, lb/gal.

$\%C$ =Percent carbon by weight.

$\%CO_2$ =CO₂ concentration, percent by volume.

32.08=Conversion factor, 385 scf CO₂/12 lb C, volume of CO₂ emitted for each pound carbon in oil.

3.2 *Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use an O₂ Monitor and a Volumetric Oil Flowmeter*

3.2.1 If relative accuracy is determined on a system basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times BAF_{system} \times V \times \rho \times \%C \times (20.9)(100)}{(20.9 - \%O_{2d}) \times (100 - \%H_2O)}$$

(Eq. I-2)

Where:

Q_s =Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system} =Bias adjustment factor for the system, as determined by Equation I-11 (for system testing) in section 3.8 of this appendix.

V =Volumetric oil flow rate, gal/hr.

ρ =Oil density, lb/gal.

$\%C$ =Percent carbon by weight.

$\%O_{2d}$ =Dry basis O₂ concentration, percent by volume.

$\%H_2O$ =Percent moisture in the flue gas.

207.6379=Conversion factor, 385 scf CO₂/12 lb C×9190 dscf O₂/1420 scf CO₂, volume of O₂ emitted for each pound carbon in oil.

3.2.2 If relative accuracy is determined on a component by component basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times 1.12 \times V \times \rho \times \%C \times (20.9)(100)}{[20.9 - (BAF_{O_2} \times \%O_{2d})] \times (100 - \%H_2O)}$$

(Eq. I-3)

Where:

Q_s Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{O_2} =Bias adjustment factor for the O₂ monitor, as determined by section 3.7.2 of this appendix.

V =Volumetric oil flow rate, gal/hr.

ρ =Oil density, lb/gal.

$\%C$ =Percent carbon by weight.

$\%O_{2d}$ =Dry basis O₂ concentration, percent by volume.

$\%H_2O$ =Percent moisture in the flue gas.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

207.6379=Conversion factor, 385 scf CO₂/12 lb C×9190 dscf O₂/1420 scf CO₂, volume of O₂ emitted for each pound carbon in oil.

3.3 *Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use a CO₂ Monitor and a Mass Oil Flowmeter*

$$Q_s = \frac{32.08 \times BAF_{system} \times M \times \%C}{\%CO_2}$$

(Eq. I-4)

Where:

Q_s =Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system} =Bias adjustment factor for the system, as determined by Equation I-10A or I-10B (for component by component testing) in section 3.7 of this appendix or by Equation I-11 (for system testing) in section 3.8 of this appendix.

M =Oil mass flow rate, lb/hr.

$\%C$ =Percent carbon by weight.

$\%CO_2$ =CO₂ concentration, percent by volume.

32.08=Conversion factor, 385 scf CO₂/12 lb C, volume of CO₂ emitted for each pound carbon in oil.

3.4 *Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use an O₂ Monitor and a Mass Oil Flowmeter*

3.4.1 If relative accuracy is determined on a system basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times BAF_{system} \times M \times \%C \times (20.9)(100)}{(20.9 - \%O_{2d}) \times (100 - \%H_2O)}$$

(Eq. I-5)

Where:

Q_s =Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system} =Bias adjustment factor for the system, as determined by Equation I-11 (for system testing) in section 3.8 of this appendix.

M =Oil mass flow rate, lb/hr.

$\%C$ =Percent carbon by weight.

$\%O_{2d}$ =Dry basis O₂ concentration, percent by volume.

$\%H_2O$ =Percent moisture in the flue gas.

207.6379=Conversion factor, 385 scf CO₂/12 lb C×9190 dscf O₂/1420 scf CO₂, volume of O₂ emitted for each pound carbon in oil.

3.4.2 If relative accuracy is determined on a component by component basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times 1.12 \times M \times \%C \times (20.9)(100)}{[20.9 - (BAF_{O_2} \times \%O_{2d})] \times (100 - \%H_2O)}$$

(Eq. I-6)

Where:

Q_s =Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{O_2} =Bias adjustment factor for the O₂ monitor, as determined by section 3.7.2 of this appendix.

M=Oil mass flow rate, lb/hr.

%C=Percent carbon by weight.

%O_{2d}=Dry basis O₂ concentration, percent by volume.

%H₂O=Percent moisture in the flue gas.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

207.6379=Conversion factor, 385 scf CO₂/12 lb C×9190 dscf O₂/1420 scf CO₂, volume of O₂ emitted for each pound carbon in oil.

3.5 *Hourly Volumetric Flow during Combustion of Natural Gas Only for Systems that Use a CO₂ Monitor and a Volumetric Gas Flowmeter*

$$Q_s = \frac{0.01 \times BAF_{\text{system}} \times V \times GCV \times F_c}{\%CO_2}$$

(Eq. I-7)

Where:

Q_s =Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system} =Bias adjustment factor for the system, as determined by Equation I-10A or I-10B (for component by component testing) in section 3.7 of this appendix or by Equation I-11 (for system testing) in section 3.8 of this appendix.

$$Q_s = \frac{0.01 \times BAF_{\text{system}} \times V \times GCV \times F_d \times (20.9)(100)}{(20.9 - \%O_{2d}) \times (100 - \%H_2O)}$$

(Eq. I-8)

Where:

Q_2 =Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system} =Bias adjustment factor for the system, as determined by Equation I-11 (for system testing) in section 3.8 of this appendix.

V=Volumetric gas flow rate, 100 scfh.

GCV=Gross calorific value of the natural gas, Btu/scf.

F_d =Dry basis, O₂-based F-factor for natural gas, 8,710 dscf/mmBtu.

%O_{2d}=Dry basis O₂ concentration, percent by volume.

%H₂O=Percent moisture in the flue gas.

V=Volumetric gas flow rate, 100 scfh.

GCV=Gross calorific value of the gaseous fuel, Btu/scf.

F_c =Carbon-based F-factor of 1040 scf CO₂/mmBtu for natural gas, from section 3 of appendix F to this part.

%CO₂=CO₂ concentration, percent by volume.

0.01=Conversion factor, 10⁻⁶ mmBtu/Btu×10² scf/100 scf×10² (conversion of fraction to percentage).

3.6 *Hourly Volumetric Flow during Combustion of Natural Gas Only for Systems that Use an O₂ Monitor and a Volumetric Gas Flowmeter*

3.6.1 Determining Flow for Systems that Are Tested on a System Basis

0.01=Conversion factor, 10⁻⁶ mmBtu/Btu × 10² scf/100 scf×10² (conversion of fraction to percentage).

3.6.2 Determining Flow for Systems that are Tested on a Component-by-Component Basis

$$Q_s = \frac{0.01 \times 1.12 \times V \times GCV \times F_d \times (20.9)(100)}{[20.9 - (BAF_{O_2} \times \%O_{2d})] \times (100 - \%H_2O)}$$

(Eq. I-9)

Where:

Q_s =Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{O_2} =Bias adjustment factor for the O₂ monitor, as determined by section 3.7.2 of this appendix.

V=Volumetric gas flow rate, 100 scfh.

GCV=Gross calorific value of the natural gas, Btu/scf.

F_d =Dry basis, O₂-based F-factor for natural gas, 8,710 dscf/mmBtu.

%O_{2d}=Dry basis O₂ concentration, percent by volume.

%H₂O=Percent moisture in the flue gas.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

0.01=Conversion factor, 10⁻⁶ mmBtu/Btu × 10² scf/100 scf × 10² (conversion of fraction to percentage).

3.7 Bias Adjustment Factor for a System Tested Component-by-Component

3.7.1 Calculation of the System Bias Adjustment Factor, BAF_{system} , for CO₂ Monitor

Calculate the mean difference of the relative accuracy test data for the CO₂ monitor, \bar{d} , using Equation A-7 in section 7.3.1 of appendix A to this part. Calculate the confidence coefficient (cc) using Equation A-9 in section 7.3.3 of appendix A to this part.

If $\bar{d} < -cc$, where \bar{d} is defined by Equation A-7, calculate the bias adjustment factor for a system tested component by component, as follows:

$$BAF_{\text{system}} = \frac{1.12}{\left(1 + \frac{\bar{d}}{CEM}\right)}$$

(Eq. I-10A)

If $\bar{d} \geq -cc$, then

$BAF_{\text{system}}=1.12$

(Eq. I-10B)

Where:

BAF_{system} =Overall bias adjustment factor for the appendix I flow monitoring system.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

\bar{d} =Mean difference between the reference method and continuous emission monitoring system (RM_i-CEM_i) as defined in Equation A-7 in section 7.3.1 of appendix A to this part.

\bar{CEM} =Mean of the data values provided by the CO₂ monitor during the relative accuracy test audit.

3.7.2 Calculation of the Component Bias Adjustment Factor, BAF_{O_2} , for O₂ Monitor

Perform the bias test for the O₂ monitor using the procedures in section 7.6 of

appendix A to this part and, if necessary, calculate a bias adjustment factor.

3.8 *Bias Adjustment Factor for a System Tested on a System Level*

Calculate the bias adjustment factor for a system tested on a system level, as follows:

$BAF_{\text{System}}=GAF_{\text{flow rate}}$

(Eq. I-11)

Where:

BAF_{system} =Overall bias adjustment factor for the appendix I flow monitoring system.

$BAF_{\text{flow rate}}$ =Bias adjustment factor from relative accuracy testing using Reference Method 2 for volumetric flow rate.

4. Missing Data

4.1 The owner or operator shall provide substitute volumetric flow data using the flow missing data procedures in subpart D of this part.

4.2 [Reserved]

5. Recordkeeping and Reporting

Follow the applicable monitoring plan provisions of § 75.53, the applicable general recordkeeping provisions of § 75.57, the specific recordkeeping provisions of § 75.58(g), the certification recordkeeping provisions of § 75.59(d)(1), and the quality assurance test recordkeeping provisions of § 75.59(d)(2). Maintain a quality assurance/quality control plan, as specified in appendix

B to this part. Follow the reporting provisions of §§ 75.60 through 75.67.

77. Appendix J to part 75 is removed and reserved.

[FR Doc. 98-11749 Filed 5-20-98; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 75

[FRL-6007-7]

RIN 2060-AH64

Acid Rain Program: Determinations under EPA Study of Bias Test and Relative Accuracy and Availability Analysis

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed determinations and proposed rulemakings.

SUMMARY: Title IV of the Clean Air Act Amendments of 1990 (the Act) authorizes EPA to establish a program to reduce the adverse effects of acidic deposition. The Act requires electric utilities affected by the Acid Rain Program to install continuous emission monitoring systems (CEMS) to measure emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon dioxide (CO₂). On January 11, 1993, Continuous Emission Monitoring regulations were published. They established procedures and requirements for installing, certifying, operating, and quality assuring CEMS at Acid Rain affected utility units. In response to comments and litigation from representatives of the electric utility industry and environmental advocacy groups, provisions were incorporated in the CEMS regulations requiring EPA to conduct studies, reach determinations, and, if necessary, initiate rulemakings on the appropriateness of retaining or revising three elements in the CEMS regulations: the bias test, relative accuracy test, and the availability trigger conditions of the Missing Data Substitution Procedure. This Notice of Proposed Rulemaking presents EPA's proposed determinations and consequent proposed rule revisions.

DATES: *Comments.* Comments on the proposed determinations and rule revisions must be received on or before July 6, 1998.

Public Hearing. Anyone requiring a public hearing must contact EPA no later than June 1, 1998. If a hearing is held, it will take place June 5, 1998, beginning at 10:00 a.m.

ADDRESSES: *Comments.* All written comment must be identified with the appropriate docket number (Docket No. A-97-56) and must be submitted in duplicate to EPA Air Docket Section (6102), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW, Washington, D.C. 20460.

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

Docket. Docket No. A-97-56, containing supporting information used to develop the proposed determinations and rule revisions is available for public inspection and copying from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section at the above address.

FOR FURTHER INFORMATION CONTACT: Elliot Lieberman at (202) 564 9136, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M St., S.W., Washington, D.C. 20460; or the Acid Rain Hotline at (202) 564 9620. Electronic copies of this notice and technical support documents can be accessed through the Acid Rain Division website at <http://www.epa.gov/acidrain>.

SUPPLEMENTARY INFORMATION:

- I. EPA Studies Under 40 CFR 75.7
 - A. Background
 - B. Collaborative Field Study
 - C. Certification Test Study
 - D. Proposed Findings and Conclusions
- II. EPA Analyses in Response to 40 CFR 75.8
 - A. Background
 - B. Relative Accuracy
 - C. Availability Trigger Conditions for Missing Data Substitution Procedure
- III. Proposed Rule Revisions
- IV. Administrative Requirements
 - A. Executive Order 12866
 - B. Unfunded Mandates Act
 - C. Paperwork Reduction Act
 - D. Regulatory Flexibility

I. EPA Studies Under 40 CFR 75.7

A. Background

To ensure a consistent level of precision and accuracy in the emission measurements obtained across the Acid Rain Program, Part 75 of the Acid Rain regulations requires a series of performance tests to be conducted on each CEMS both at initial certification and periodically thereafter. Among the required performance tests is the relative accuracy test audit (RATA) in which a minimum of nine simultaneous measurements are taken from a unit's installed CEMS and an EPA approved

reference method. The paired RATA data are then subjected to two statistical tests: The relative accuracy test, which establishes the degree of accuracy of the CEMS relative to the reference method; and the bias test, which uses a t-statistic to determine if the CEMS measurements are consistently lower than the reference method measurements. See 40 CFR Part 75, Appendix A and B.

As stated in the preamble of the January 1993 regulations, EPA found that "both statistical theory and field test results show that the bias test is a sound and effective statistical procedure for detecting consistent measurement error in the long-term operation of a CEMS" (58 FR 3590, 3627 (1993)). However, at the time of promulgation of the Acid Rain regulations, although utilities had extensive experience with the relative accuracy test, they had virtually no previous experience with the bias test. This unfamiliarity led to several concerns with the bias test. Thus, the January 1993 regulations committed EPA to conduct field studies to determine "whether there are statistically significant variances" in the EPA-approved reference methods that utilities use to test the performance of the CEMS installed under the Acid Rain Program and "whether the bias test should be adjusted to compensate for statistical variances in the reference method" (58 FR 3628).

In particular, EPA was required to:

1. Investigate whether there are statistically significant variances in the EPA reference methods (Issue #1);
2. Distinguish between the variability in reference monitor readings attributable to measurement error and the variability due to the choice of reference monitor among those certified by the Agency (Issue #2);
3. Investigate possible differences in bias test failure rates by emission levels (Issue #3); and
4. Assess whether any adjustments are necessary to properly determine measurement bias (Issue #4).

The regulations called for the completion of a study addressing these issues by October 31, 1993. In response, EPA conducted two studies. The first was a collaborative field study, involving four independent reference method test teams, at Big Rivers Electric Corporation's Green Generating Station, Unit 2, in Sebree, Kentucky. This location was specifically selected for testing because its relatively low range of SO₂ emission concentrations (from 56 ppm to 231 ppm) would allow EPA to examine bias test failure rates at SO₂ emission levels different from those prevailing in previous field studies and consider an industry concern that

contradictory bias test results were more likely to occur at low, than at high, emission concentrations. Field work for this study was completed from August 16–31, 1993. Separate data summary (Docket Item, A-97-56, II-A-1) and statistical analyses reports summary (Docket Item, A-97-56, II-A-2) were completed in March 1994 and September 1996 respectively.

The second study involved collection and analysis of bias test results from the field tests conducted by affected units under Part 75 for certification of their CEMS. The certification test data, including the bias test, were submitted to EPA from November 1993 to September 1996. The study results reported here (and contained in Docket Item, A-97-56, II-A-3) were available in 1997 only after the CEMS at the majority of both Phase I and Phase II (lower emitting) units had been received and certified by EPA.

B. Collaborative Field Study

In the collaborative field study at Unit 2 of Big Rivers Electric Corporation's Green Generating Station ("Green Unit 2"), four labs (i.e., test teams) simultaneously performed Reference Methods 6C (for SO₂), 7E (for NO_x), and 3A (for CO₂). To test the two general monitoring technologies available for performing the reference methods, two of the teams used "wet-basis" sampling techniques and two used "dry-basis" techniques. In the "wet-basis" sampling techniques, a dilution probe is used to extract a diluted sample of the effluent from the stack gas. The diluted gas sample is then analyzed using an ambient-level analyzer (e.g., pulsed fluorescence for SO₂, chemiluminescence for NO_x, and infrared absorption for CO₂), which does not require removal of moisture from the gas sample. In the "dry-basis" sampling techniques, a gas sample is extracted from the effluent stream without dilution. Moisture is condensed from the gas sample and the resulting dry sample is then analyzed using a source-level analyzer (infrared or ultraviolet for SO₂, chemiluminescence for NO_x, and infrared for CO₂).

Seventy-two runs of usable data (out of 76 total runs) were collected by the four labs. Concurrent measurements were also collected from Green Unit 2's SO₂, NO_x, and CO₂ continuous emissions monitoring systems, previously certified under the Acid Rain Program. On 36 of the runs, each lab and the unit's CEMS used separate calibration gases as required under 40 CFR Part 75. On the other 36 runs, all labs and the plant's CEMS shared common gases when calibrating.

Issues #1 and #2 involve evaluation of the sources of variability inherent in EPA's reference methods. In the consideration of these two issues only the reference method measurements were analyzed, not the unit's CEMS. Issues #3 and #4 involve a comparison of the CEMS and the reference method measurements to determine if bias (systematic error) is detected in the CEMS measurement. In the consideration of these two issues, the unit's CEMS measurements were paired with each of the four lab's concurrent reference method measurements. This produced four sets of concurrent Relative Accuracy Test Audits (RATA's) which could be used in evaluating bias test result consistency across the four labs.

To address the first two issues concerning the sources and extent of variability inherent in the reference methods, the collaborative field study employed an experimental design (technically known as a "randomized complete block design") which allowed the quantification of the relative variability associated with (i) among-laboratory variation, (ii) variation between monitoring technologies (i.e., "wet-basis" or "dry-basis" sampling techniques), (iii) the variability associated with different calibration gas scenarios (i.e., separate or shared calibration gases), and (iv) random error.

Applying an analysis of variance (ANOVA) statistical procedure to the field study data, EPA found that the overall variation in the reference methods, considering all the monitoring technologies and calibration gas scenarios, was 2.93%RSD (Relative Standard Deviation) for SO₂, 2.01%RSD for NO_x, and 1.59%RSD for CO₂. Reference method variations below approximately 3%RSD are consistent with the findings of an earlier collaborative field study, reported in Docket Item, A-97-56, II-A-5, where variations of 1.4%RSD and 2.9%RSD were found for SO₂ and NO_x respectively. (The variation for CO₂ is not available from the earlier study since that study did not include CO₂ reference method measurements.) Based on these findings, with respect to Issue #1 EPA believes that the statistically significant variances in the EPA reference methods are small.

The analysis in the most recent collaborative study also revealed that the range in the Relative Standard Deviation due to the choice of reference method monitor (i.e., different analyzers using "wet-basis" or "dry-basis" technology) among allowable reference method technologies was very small (below 1%RSD) whether the labs used

separate or shared calibration gases. Consequently, EPA believes with respect to Issue #2 that the variability due to the choice of reference method monitor among those available is very small.

As noted earlier, Issues #3 and #4 require consideration of simultaneous measurements by the unit's CEMS along with the four test labs. To respond to Issue #3, concerning the consistency of the bias test results, the field test data were analyzed to determine how much agreement was found among the four labs as to whether the CEM was biased or not biased when current provisions of Part 75 are followed. In particular, the consistency in bias test results was evaluated by counting the number of concurrent RATA's in which agreement among the four test teams was 100% (all four labs agree), 75% (three out of four labs agree) and 50% (two labs find bias and two find no bias). For each pollutant there was never less than 75% agreement among the test teams when the reference methods and the installed CEMS were each calibrated using independently selected calibration gases, as is required under 40 CFR Part 75. For NO_x and CO₂ there was always 100% agreement. For SO₂ there was 100% agreement in bias test results in more than 76% of the concurrent RATA's.

These test results lead EPA to believe that even at a site exhibiting low SO₂ emission concentrations, there is a high degree of consistency in bias test results.

C. Certification Test Study

To respond further to Issue #3, EPA analyzed the consistency in bias test results across the universe of affected units, by conducting a study of the bias test results for all CEMS for which certification tests data were submitted under Part 75 between November 1993 and September 1996. To see how test results were affected by emission levels, the pass/fail rates at different concentrations (SO₂) and emission rates (NO_x) were compared for 1023 SO₂ and 1293 NO_x bias tests submitted under the Acid Rain Program. This analysis was not performed on CO₂ monitors, because under Part 75 units are not required to perform the bias test on their CO₂ monitors.

Grouping monitors according to the average concentration level (for SO₂ CEMS) and average emission rate (for NO_x CEMS), reported by the CEMS during the RATA, the pass/fail rates were plotted at regular increasing SO₂ emission concentration levels and NO_x emission rates. The resulting graphs revealed that the percentage of passes and fails remained relatively consistent

across concentration and emission rate categories. For example, for all SO₂ monitors, 73% (750 out of a total of 1023 monitors) passed the bias test. Assigning each tested monitor to one of fourteen 100 ppm categories, beginning at 0–100 ppm and ending at above 1300 ppm, showed that the percent of passing monitors in all but three of the concentration categories fell between 70 and 90%. The three categories whose passing rates were outside this range were 400–500 ppm (56% passing), 600–700 ppm (69%), and above 1300 ppm (63%). Thus, there was little or no apparent correlation between concentration level and bias test failure rates.

The graphical analysis for SO₂ monitors was confirmed by calculation of the r-squared value for the data. The r-squared value is a measure of the strength of the linear relationship between two data sets. R-squared can take on values from zero to one. A high r-squared value, i.e., closer to 1 than to 0, would suggest that the bias test pass/fail rate is highly correlated with the emission concentration level, e.g., that bias test failure is more likely with low emission concentration as suggested by utilities. A low r-squared value, i.e., closer to 0 than to 1, would suggest the absence of correlation between the bias pass/fail rate and the emission concentration level. For the plotted SO₂ data, the r-squared value was low: 0.0109.

The same graphical and statistical analysis was performed on the certification test data submitted for NO_x CEMS. Bias test pass/fail rates for 1293 NO_x monitors were divided into sixteen 0.1 lb/mmBTU categories. Considering all these categories, 67% (866 out of a total of 1293 monitors) passed the bias test. A plot of the data by emission category showed the bias test passing rate fell between 65% and 85% in all but of 3 of the 16 NO_x emission categories. The three emission rate categories whose passing rates were outside this range were not correlated to the measured NO_x emission rate: 0.1–0.2 lb/mmBTU (47% passing), 0.4–0.5 lb/mmBTU (59%), and 1.4–1.5 lb/mmBTU (50%). Again, there was little or no apparent correlation between bias test pass/fail rates and emission rate, and this was confirmed by the statistical analysis. The r-squared value for the NO_x data was low: 0.1109.

Thus, the graphical and statistical analysis performed in the certification test study indicates consistent bias test results across emission levels.

D. Proposed Findings and Conclusions

Based on the analyses performed to address Issues #1–3 in the collaborative and certification field studies, EPA considered Issue #4, concerning the necessity and feasibility of adjustments to the bias test. EPA currently believes that the small variability in the reference methods (less than 3%RSD across all gas scenarios and monitor technologies) indicates that there is very low probability that a continuous emission monitoring system will fail the bias test for reasons other than the presence of true measurement bias in the CEMS. The high level of consistency in bias test results seems to support this view.

Based on these studies, EPA proposes to find that:

1. The variability attributable to measurement error and to the choice of reference monitor technology in the Agency's approved test methods for SO₂, NO_x, and CO₂ is low (below 3.0% Relative Standard Deviation).
2. Differences in measurement variability among different allowable reference method technologies are small (below 1.0% RSD).
3. There is a high occurrence of consistency in bias test results.
4. There is no evidence that bias test failure rates are significantly influenced by emission levels.

Documentation of these proposed findings can be found in four docket items: A Collaborative Field Evaluation of EPA Test Methods 6C, 7E, and 3A (March 1994) (Docket Item, A–97–56, II–A–1) gives a detailed description of the collaborative field test activities, site characteristics, and equipment employed, presents data obtained in the field study, and discusses preliminary findings on the variability of the reference methods. A second report, An Operator's Guide to Eliminating Bias in CEM System (November 1994) (Docket Item, A–97–56, II–A–6) is an independent technical guidance document advising environmental technicians on procedures for detecting and correcting engineering problems that could produce measurement bias in CEM systems. A third report, Statistical Analysis of Reference Method Variability and Bias Test Consistency in the Collaborative Field Study of EPA Test Methods 6C, 7E, and 3A at Big Rivers Electric Corporation, Green Generating Station, Unit 2 (September 1996) (Docket Item, A–97–56, II–A–2), focuses on the analysis of the collaborative study field data, reports the results of this analysis with respect to the four issues that the study was designed to address, and, based on this

analysis, makes recommendations concerning whether adjustments are needed to the bias test. Finally, the graphs and supporting data from the certification test study can be found in "Bias Test Pass/Fail Rates at Different SO₂ and NO_x Emission Levels as Reported in Certification Relative Accuracy Test Audits (RATA's) submitted through September 1996 under 40 CFR Part 75." (December 1997) (Docket Items, A–97–56, II–A–3 and II–A–4).

Based on the proposed findings enumerated above, EPA proposes to determine that adjustments to the equations in the bias test are technically unnecessary to properly determine measurement bias. EPA therefore proposes not to initiate a rulemaking to change the bias test under § 75.7.

II. EPA Analyses in Response to 40 CFR 75.8

A. Background

In accordance with a settlement agreement, signed on April 17, 1995 in *Environmental Defense Fund v. Browner*, No. 93–1203 and consolidated cases (D.C. Cir., 1993), which addressed various CEMS issues, § 75.8 was adopted as part of the direct final rule, dated May 17, 1995, amending the January 11, 1993 rule's CEM provisions. Section 75.8 required EPA to evaluate the appropriateness of the current relative accuracy and availability trigger conditions for missing data substitution for SO₂, NO_x, and CO₂ CEMS and flow monitors. This evaluation was to be based on initial certification test data and quarterly report data for the 1993–1996 period. Using the evaluation, EPA was to determine whether to retain the current specifications or propose alternative performance specifications. A report evaluating this data was to be prepared by July 1, 1997, and EPA is to issue either a notice determining that the current rule provisions are appropriate or a notice proposing revisions. Any proposal revising the current rule is to be issued by October 31, 1997 and finalized by October 31, 1998. The results of EPA's evaluations of the current relative accuracy and availability trigger conditions are described below.

B. Relative Accuracy

Relative accuracy is a statistical indicator of how closely the measurements by an installed CEM approximate those obtained by a concurrently used EPA reference method during a 9–12 run field demonstration (known as the relative accuracy test audit (RATA)) that must

be performed periodically for each CEMS under Part 75. Relative accuracy is expressed as a percent deviation of the CEMS results from the reference method results. The lower the relative accuracy value for a CEMS, the closer its measurements are to the reference method. Under 40 CFR Part 75, Appendix A, § 3, and Appendix B, § 2.3.1, all SO₂, NO_x, and CO₂ CEMS are required to have in a RATA a relative accuracy of 10%. Those that have a superior relative accuracy of 7.5% or less have one year to undergo their next RATA. Those that have a relative accuracy equal to or less than the required 10% but greater than 7.5% must undergo their next RATA within six months. The tighter specification of 7.5% is referred to as the "reduced frequency standard," while the 10% specification is known as the "normal frequency standard." For flow monitors the normal frequency standard is 15%, while the reduced frequency standard is 10%. On January 1, 2000 the normal and reduced frequency standards for flow monitors will be lowered to correspond to the standards for the pollutant CEMS, i.e., 10% and 7.5% respectively.

The evaluation of initial certification test data submitted for 1993–1996 showed that the average relative accuracy was 3.42% for the 965 SO₂ CEMS installed under the Acid Rain Program, 3.62% for 1272 NO_x CEMS, 3.28% for 1097 CO₂ CEMS, and 6.88% for 1070 flow monitors. This means that for all pollutants and flow, the average relative accuracy was below the reduced frequency standard. Furthermore, 91.3% of all SO₂ CEMS, 94.1% of all NO_x CEMS, 96.3% of all CO₂ CEMS, and 91.9% of all flow monitors met their respective reduced frequency standard. See Docket Item, A–97–56, II–A–7 for a complete analysis of the certification test relative accuracy results.

A similar evaluation was performed on the relative accuracy test results reported in quarterly reports for the 1994–1996 period. This analysis showed that the average relative accuracy over the three years of data was 3.49% on 2802 SO₂ RATAs, 3.67% on 3935 NO_x RATAs, 3.06% on 2736 CO₂ RATAs, and 5.78% on 3019 flow RATAs. Like the certification test results, the data in the quarterly reports indicate that for each type of monitor, the average relative accuracy was below the reduced frequency standard. In addition, on 96.2% of the SO₂ RATAs, 96.0% of the NO_x RATAs, 97.9% of the CO₂ RATAs, and 93.5% of flow RATAs, the monitors met their respective reduced frequency standard. A complete analysis of the quarterly report relative

accuracy test results can be found in Docket Item, A–97–56, II–A–8.

The relative accuracy test results obtained by these installed CEMS imply that no appreciable improvement in achieved relative accuracies could be expected unless the relative accuracy standard were brought down to or below these currently achieved average relative accuracies. However, studies cited above (Docket Item, A–97–56, II–A–2 and II–A–5) of the variability of the reference methods for SO₂, NO_x, and CO₂ suggest that such reduced relative accuracy standards might be beyond the technological limits of current monitoring technology since they approach the variability inherent in the reference methods themselves. Thus, tightening the relative accuracy standards further for these CEMS is unlikely to produce a corresponding improvement in the achievable relative accuracy.

Moreover, the existing regulations already provide that the normal and reduced frequency relative accuracy standards for flow monitors will be tightened to the same levels as for the other CEMS beginning in the year 2000. In light of the already low average relative accuracy (reflecting high monitor accuracy) for flow monitors, there is little or no basis at this time for concluding that any further tightening would be appropriate. In addition, EPA believes that the results of the tightening in 2000 should be evaluated before any further tightening is contemplated.

Therefore, based on the evaluation required under § 75.8, the Agency proposes to conclude that the current performance specifications for relative accuracy are appropriate at this time.

C. Availability Trigger Conditions for Missing Data Substitution Procedure

In 40 CFR 75.30–75.38 (Subpart D) a missing data procedure is prescribed for calculating emissions when valid data are not being supplied by a unit's continuous emissions monitoring system. The missing data procedure is a multi-tiered computational routine for deriving a substitution value from values previously recorded, or the highest potential values, by the monitor. The procedure is based on the premise that the lower the annual monitor availability and/or the longer the gap in recorded data, the more conservative the value to be substituted.

In concert, two trigger conditions determine the conservativeness of the substituted value. The first trigger condition is annualized monitor availability, i.e., the percentage of the immediately preceding 8760 unit operating hours in which valid, quality

assured data was obtained. The second trigger condition is the length of the current period during which valid data are not being produced. Current availability trigger conditions include three tiers: (1) less than 90% availability, (2) equal to or greater than 90% but less than 95% availability, and (3) 95% or greater availability.

To determine if retaining the current availability trigger conditions is appropriate, the Agency analyzed the annual percent monitor availability (PMA) as reported in the 1994–1996 quarterly emission reports. The PMA indicates the proportion of the operating hours in each year that the monitor was providing valid, quality assured measurements. High PMAs would indicate that current trigger conditions are providing a sufficient incentive for keeping monitors operating properly.

The evaluation of the quarterly report data for 1994–1996 showed that the average PMA for SO₂ CEMS was 94.7% in 1994, 96.7% in 1995, and 97.2% in 1996. For the same three year period it was 91.8%, 94.1%, and 95.8% for NO_x CEMS, and 95.0%, 96.3%, and 97.0% for flow monitors. As a rule, separate percent monitor availabilities for the CO₂ CEMS are not routinely reported, since CO₂ CEMS usually serve as diluent components in NO_x systems. However, the average PMA for CO₂ CEMS in a given year must be at least as good as the corresponding average of the reported NO_x PMAs. Not only are the average PMAs above the 95% availability trigger level, but they have also consistently increased in each successive year of the Acid Rain Program. To appreciably improve monitor availabilities would require increasing the third tier availability trigger up to or above the high average availabilities currently being achieved. EPA believes that such an increase in the required availabilities would be close to or beyond the limits of what is reasonable to expect from current CEMS technology when properly operated under the conditions prevailing in utility stacks. A complete summary of the PMA's submitted in the 1994–1996 quarterly reports can be found in Docket Item, A–97–56, II–A–9.

Moreover, any tightening of the availability trigger conditions would require reprogramming of most affected units' data acquisition and handling systems, which automatically calculate and record the appropriate substitution values for periods when valid CEMS data are not available. Given the current high levels of monitor availability, there is little or no basis for finding that adjusting the trigger conditions would improve availability sufficiently to

justify the reprogramming costs that such a change would impose.

Therefore, based on the evaluation required under § 75.8, the Agency proposes to determine that retaining the current performance specifications for availability trigger conditions is appropriate at this time.

III. Proposed Rule Revisions

Having completed the studies and evaluations required in 40 CFR 75.7 and 75.8 and in light of EPA's determinations proposed above for retaining current rule provisions for the bias test, relative accuracy, and availability trigger conditions, EPA proposes revising Part 75 to delete §§ 75.7 and 75.8.

IV. Administrative Requirements

A. Executive Order 12866

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

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

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

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

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

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

B. Unfunded Mandates Act

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

Because this proposed rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less than \$100 million in any one year, the Agency has not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, the Agency is not required to develop a plan with regard to small governments.

As discussed above, the proposed rule would eliminate two sections requiring studies and evaluations by EPA of certain existing regulatory provisions and would not include any other

changes to the existing regulations. The proposed rule therefore would not change in any way the expenditure by State, local, and tribal governments or the private sector, or the effect on small governments, resulting from the existing regulations.

C. Paperwork Reduction Act

This action proposing revisions to the continuous emission monitoring regulations would not impose any new information collection burden. OMB has previously approved the information collection requirements contained in the continuous emission monitoring regulations, 40 CFR part 75, under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* Note, however, that the Agency is proposing other revisions to the continuous emission monitoring regulations in a separate action in today's **Federal Register** and that those revisions would result in a change to the current information collection burden.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

D. Regulatory Flexibility

The Regulatory Flexibility Act, 5 U.S.C. 601, *et seq.*, generally requires federal agencies to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions.

As discussed above, the proposed rule would eliminate two sections requiring studies and evaluations by EPA and would not include any other changes to the existing regulations. The proposed rule therefore does not change in any way the potential impacts on small entities resulting from the existing regulations. Therefore, I hereby certify

that this action will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 75

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

Dated: April 27, 1998.

Carol M. Browner,
Administrator.

For the reasons set out in the preamble, part 75 of title 40, chapter 1 of the Code of Federal Regulations is proposed to be amended as follows:

PART 75—[AMENDED]

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

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

2. Section 75.7 is removed and reserved.

3. Section 75.8 is removed and reserved.

[FR Doc. 98-11750 Filed 5-20-98; 8:45 am]

BILLING CODE 6560-50-P