2.2.3.11 The 95th percentile value of hourly NO_X pollutant concentration, in ppm.

2.2.3.12 The maximum value of hourly NO_X pollutant concentration, in ppm.

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

2.2.5 When a bias adjustment is necessary for the flow monitor and/or the NO_X-diluent continuous emission monitoring system (and/or the NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2)), apply the adjustment factor to all monitor or continuous emission monitoring system data values placed in the load ranges.

2.2.6 Use the calculated monitor or monitoring system data averages, maximum values, and percentile values to substitute for missing flow rate and NO_X emission rate data (and where applicable, NO_X concentration data) according to the procedures in subpart D of this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26547, 26548, May 17, 1995; 63 FR 57313, Oct. 27, 1998; 64 FR 28652, May 26, 1999]

APPENDIX D TO PART 75—OPTIONAL SO_2 EMISSIONS DATA PROTOCOL FOR GAS-FIRED AND OIL-FIRED UNITS

1. APPLICABILITY

1.1 This protocol may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 mass emissions and heat input from: gas-fired units, as defined in §72.2 of this chapter, or oil-fired units, as defined in §72.2 of this chapter. Section 2.1 of this appendix provides procedures for measuring oil or gaseous fuel flow using a fuel flowmeter, section 2.2 of this appendix provides procedures for conducting oil sampling and analysis to determine sulfur content and gross calorific value (GCV) of fuel oil, and section 2.3 of this appendix provides procedures for determining the sulfur content and GCV of gaseous fuels.

1.2 Pursuant to the procedures in §75.20, complete all testing requirements to certify use of this protocol in lieu of a flow monitor and an SO_2 continuous emission monitoring system. Complete all testing requirements no later than the applicable deadline specified in §75.4. Apply to the Administrator for initial certification to use this protocol no later than 45 days after the completion of all certification tests. Whenever the monitoring method is to be changed, reapply to the Administrator for recertification of the new monitoring method.

2. PROCEDURE

2.1 Fuel Flowmeter Measurements

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

2.1.1 Measure the flow rate of each fuel entering and being combusted by the unit. If, on an annual basis, more than 5.0 percent of the fuel from the main pipe is diverted from the unit without being burned and that diversion occurs downstream of the fuel flowmeter, an additional in-line fuel flowmeter is required to account for the unburned fuel. In this case, record the flow rate of each fuel combusted by the unit as the difference between the flow measured in the pipe leading to the unit and the flow in the pipe diverting fuel away from the unit. However, the additional fuel flowmeter is not required if, on an annual basis, the total amount of fuel diverted away from the unit, expressed as a percentage of the total annual fuel usage by the unit is demonstrated to be less than or equal to 5.0 percent. The owner or operator may make this demonstration in the following manner:

2.1.1.1 For existing units with fuel usage data from fuel flowmeters, if data are submitted from a previous year demonstrating that the total diverted yearly fuel does not exceed 5% of the total fuel used; or

2.1.1.2 For new units which do not have historical data, if a letter is submitted signed by the designated representative certifying that, in the future, the diverted fuel will not exceed 5.0% of the total annual fuel usage; or

2.1.1.3 By using a method approved by the Administrator under §75.66(d).

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (i.e., a pipe carrying fuel for multiple units). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix are not applicable to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_X mass emissions under a state or federal NO_X mass emission reduction program. For all other units, if the fuel flowmeter is installed in a common pipe header, do one of the following:

2.1.2.1 Measure the fuel flow rate in the common pipe, and combine SO_2 mass emissions for the affected units for recordkeeping and compliance purposes; or

2.1.2.2 Provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions and heat input to each of the affected units demonstrating that the method ensures complete and accurate accounting of the actual emissions from each of the affected units included in the apportionment and all emissions regulated under this part. The information shall be provided to the Administrator through a petition submitted by the designated representative under §75.66. Satisfactory information includes: the proposed apportionment, using fuel flow measurements; the ratio of hourly integrated gross load (in MWe-hr) in each unit to the total load for all units receiving fuel from the common pipe header, or the ratio of hourly steam flow (in 1000 lb) at each unit to the total steam flow for all units receiving fuel from the common pipe header (see section 3.4.3 of this appendix); and documentation that shows the provisions of sections 2.1.5 and 2.1.6 of this appendix have been met for the fuel flowmeter used in the apportionment.

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

2.1.4 Situations in Which Certified Flowmeter is Not Required

2.1.4.1 Start-up or Ignition Fuel

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

2.1.4.2 Gas or Oil Flowmeter Used for Commercial Billing

A gas or oil flowmeter used for commercial billing of natural gas or oil may be used to measure, record, and report hourly fuel flow rate. A gas or oil flowmeter used for commercial billing of natural gas or oil is not required to meet the certification requirements of section 2.1.5 of this appendix or the quality assurance requirements of section 2.1.6 of this appendix under the following circumstances:

(a) The gas or oil flowmeter is used for commercial billing under a contract, provided that the company providing the gas or oil under the contract and each unit combusting the gas or oil do not have any common owners and are not owned by subsidiaries or affiliates of the same company;

(b) The designated representative reports hourly records of gas or oil flow rate, heat input rate, and emissions due to combustion of natural gas or oil;

(c) The designated representative also reports hourly records of heat input rate for each unit, if the gas or oil flowmeter is on a common pipe header, consistent with section 2.1.2 of this appendix;

(d) The designated representative reports hourly records directly from the gas or oil flowmeter used for commercial billing if these records are the values used, without adjustment, for commercial billing, or reports hourly records using the missing data procedures of section 2.4 of this appendix if these records are not the values used, without adjustment, for commercial billing; and

(e) The designated representative identifies the gas or oil flowmeter in the unit's monitoring plan.

2.1.4.3 Emergency Fuel

The designated representative of a unit that is restricted by its Federal, State or local permit to combusting a particular fuel only during emergencies where the primary fuel is not available is exempt from certifying a fuel flowmeter for use during combustion of the emergency fuel. During any hour in which the emergency fuel is combusted, report the hourly heat input to be the maximum rated heat input of the unit for the fuel. Additionally, begin sampling the emergency fuel for sulfur content only using the procedures under section 2.2 (for oil) or 2.3 (for gas) of this appendix. The designated representative shall also provide notice under §75.61(a)(6)(ii) for each period when the emergency fuel is combusted.

2.1.5 Initial Certification Requirement for all Fuel Flowmeters

For the purposes of initial certification, each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of 2.0 percent of the upper range value (i.e. maximum calibrated fuel flow rate) across the range of fuel flow rate to be measured at the unit. Flowmeter accuracy may be determined under section 2.1.5.1 of this appendix for initial certification in any of the following ways (as applicable): by design or by measurement under laboratory conditions; by the manufacturer; by an independent laboratory; or by the owner or operator. Flowmeter accuracy may also be determined under section 2.1.5.2 of this appendix by measurement against a NIST traceable reference method.

2.1.5.1 Use the procedures in the following standards to verify flowmeter accuracy or design, as appropriate to the type of flowmeter: ASME MFC–3M–1989 with September 1990 Errata (''Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi''); ASME MFC–4M–1986 (Reaffirmed 1990), ''Measurement of Gas Flow by Turbine Meters;'' American Gas Association Report No. 3, ''Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines'' (October 1990 Edition), Part 2: ''Specification and Installation Requirements'' (February 1991 Edition), and Part 3: ''Natural Gas Applications'' (August 1992 edition) (excluding the modified flow-calculation method in part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Second Revision, April, 1996); ASME MFC–5M–1985 (''Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters''); ASME MFC–6M–1987 with June 1987 Errata (''Measurement of Fluid Flow in Pipes Using Vortex Flow Meters''); ASME MFC–7M–1987 (Reaffirmed 1992), ''Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles;'' ISO 8316: 1987(E) ''Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank;'' American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers'', Section 3, ''Small Volume Provers'', and Section 5, ''Master-Meter Provers'', from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993); or ASME MFC–9M–1988 with December 1989 Errata (''Measurement of Liquid Flow in Closed Conduits by Weighing Method''), for all other flowmeter types (incorporated by reference under §75.6). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document such procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit, and submit a petition signed by the designated representative under §75.66(c). If the flowmeter accuracy exceeds 2.0 percent of the upper range value, the flowmeter does not qualify for use under this part.

2.1.5.2 (a) Alternatively, determine the flowmeter accuracy of a fuel flowmeter used for the purposes of this part by comparing it to the measured flow from a reference flowmeter which has been either designed according to the specifications of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix, or tested for accuracy during the previous 365 days, using a standard listed in section 2.1.5.1 of this appendix or other procedure approved by the Administrator under §75.66 (all standards incorporated by reference under §75.6). Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow rate readings over 20 minutes or longer for each meter at each of three different flow rate levels. The three flow rate levels shall correspond to:

(1) Normal full unit operating load,

(2) Normal minimum unit operating load,

(3) A load point approximately equally spaced between the full and minimum unit operating loads, and

(4) Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

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

Where:

ACC=Flowmeter accuracy at a particular load level, as a percentage of the upper range value.

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

A=Average of the three measurements of the flowmeter being tested.

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

(c) Notwithstanding the requirement for calibration of the reference flowmeter within 365 days prior to an accuracy test, when an in-place reference meter or prover is used for quality assurance under section 2.1.6 of this appendix, the reference meter calibration requirement may be waived if, during the previous in-place accuracy test with that reference meter, the reference flowmeter and the flowmeter being tested agreed to within ±1.0 percent of each other at all levels tested. This exception to calibration and flowmeter accuracy testing requirements for the reference flowmeter shall apply for periods of no longer than five consecutive years (i.e., 20 consecutive calendar quarters).

2.1.5.3 If the flowmeter accuracy exceeds the specification in section 2.1.5 of this appendix, the flowmeter does not qualify for use for this appendix. Either recalibrate the flowmeter until the flowmeter accuracy is within the performance specification, or replace the flowmeter with another one that is demonstrated to meet the performance specification. Substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix until quality assured fuel flow data become available.

2.1.5.4 For purposes of initial certification, when a flowmeter is tested against a reference fuel flow rate (i.e., fuel flow rate from another fuel flowmeter under section

2.1.5.2 of this appendix or flow rate from a procedure performed according to a standard incorporated by reference under section 2.1.5.1 of this appendix), report the results of flowmeter accuracy tests using the following Table D–1.

TABLE D–1.—TABLE OF FLOWMETER ACCURACY RESULTS

Test number:_______ Test completion date[1]:_________________ Test completion time[1]:___________
Reinstallation date[2] (for testing under 2.1.5.1 only):_________________ Reinstallation time[2]:___________
Unit or pipe ID: Component/System ID:
Flowmeter serial number: Upper range value:
Units of measure for flowmeter and reference flow readings:

Measurement level (percent of URV)	Run No.	Time of run (HHMM)	Candidate flowmeter reading	Reference flow reading	Percent accuracy (percent of URV)
Low (Minimum) level	1	....	....	....	....
____ percent[3] of URV	2	....	....	....	....
	3	....	....	....	....
	Average	....	....	....	....
Mid-level	1	....	....	....	....
____ percent[3] of URV	2	....	....	....	....
	3	....	....	....	....
	Average	....	....	....	....
High (Maximum) level	1	....	....	....	....
____ percent[3] of URV	2	....	....	....	....
	3	....	....	....	....
	Average	....	....	....	....

[1] Report the date, hour, and minute that all test runs were completed.
[2] For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.
[3] It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

2.1.6 Quality Assurance

(a) Test the accuracy of each fuel flowmeter prior to use under this part and at least once every four fuel flowmeter QA operating quarters, as defined in §72.2 of this chapter, thereafter. Notwithstanding these requirements, no more than 20 successive calendar quarters shall elapse after the quarter in which a fuel flowmeter was last tested for accuracy without a subsequent flowmeter accuracy test having been conducted. Test the flowmeter accuracy more frequently if required by manufacturer specifications.

(b) Except for orifice-, nozzle-, and venturi-type flowmeters, perform the required flowmeter accuracy testing using the procedures in either section 2.1.5.1 or section 2.1.5.2 of this appendix. Each fuel flowmeter must meet the accuracy specification in section 2.1.5 of this appendix.

(c) For orifice-, nozzle-, and venturi-type flowmeters, either perform the required flowmeter accuracy testing using the procedures in section 2.1.5.1 or 2.1.5.2 of this appendix or perform a transmitter accuracy test once every four fuel flowmeter QA operating quarters and a primary element visual inspection once every 12 calendar quarters, according to the procedures in sections 2.1.6.1 through 2.1.6.4 of this appendix for periodic quality assurance.

(d) Notwithstanding the requirements of this section, if the procedures of section 2.1.7 (fuel flow-to-load test) of this appendix are performed during each fuel flowmeter QA operating quarter, subsequent to a required flowmeter accuracy test or transmitter accuracy test and primary element inspection, where applicable, those procedures may be used to meet the requirement for periodic quality assurance testing for a period of up to 20 calendar quarters from the previous accuracy test or transmitter accuracy test and primary element inspection, where applicable.

2.1.6.1 Transmitter or Transducer Accuracy Test for Orifice-, Nozzle-, and Venturi-Type Flowmeters

(a) Calibrate the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. Check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at each of the following levels: the zero-level and at least two other levels (e.g., ''mid'' and ''high''), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented.

(b) Calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R - T|}{FS} \times 100 \qquad \text{(Eq. D-1a)}$$

Where:

ACC = Accuracy of the transmitter or transducer as a percentage of full-scale.
R = Reading of the NIST traceable reference value (in milliamperes, inches of water, psi, or degrees).
T = Reading of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).
FS = Full-scale range of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

(c) If each transmitter or transducer meets an accuracy of ± 1.0 percent of its full-scale range at each level tested, the fuel flowmeter accuracy of 2.0 percent is considered to be met at all levels. If, however, one or more of the transmitters or transducers does not meet an accuracy of ± 1.0 percent of full-scale at a particular level, then the owner or operator may demonstrate that the fuel flowmeter meets the total accuracy specification of 2.0 percent at that level by using one of the following alternative methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0 percent, the fuel flowmeter accuracy specification of 2.0 percent is considered to be met for that level. Or, if at a particular level, the total fuel flowmeter accuracy is 2.0 percent or less, when calculated in accordance with Part 1 of American Gas Association Report No. 3, General Equations and Uncertainty Guidelines, the flowmeter accuracy requirement is considered to be met for that level.

2.1.6.2 Recordkeeping and Reporting of Transmitter or Transducer Accuracy Results

(a) Record the accuracy of the orifice, nozzle, or venturi meter or its individual transmitters or transducers and keep this information in a file at the site or other location suitable for inspection. When testing individual orifice, nozzle, or venturi meter transmitters or transducers for accuracy, include the information displayed in the following Table D–2. At a minimum, record results for each transmitter or transducer at the zero-level and at least two other levels across the range of the transmitter or transducer readings that correspond to normal unit operation.

TABLE D–2.—TABLE OF FLOWMETER TRANSMITTER OR TRANSDUCER ACCURACY RESULTS

Test number:_______ Test completion date: _________________ Unit or pipe ID: ___________
Flowmeter serial number: Component/System ID:
Full-scale value: Units of measure:[3]
Transducer/Transmitter Type (check one):
____ Differential Pressure
____ Static Pressure
____ Temperature

Measurement level (percent of full-scale)	Run number (if multiple runs)[2]	Run time (HHMM)	Transmitter/transducer input (pre-calibration)	Expected transmitter/transducer output (reference)	Actual transmitter/transducer output[3]	Percent accuracy (percent of full-scale)
Low (Minimum) level ____ percent[1] of full-scale	....					
Mid-level ____ percent[1] of full-scale	....					
(If tested at more than 3 levels) 2nd Mid-level ____ percent[1] of full-scale	....					
(If tested at more than 3 levels) 3rd Mid-level ____ percent[1] of full-scale	....					
High (Maximum) level ____ percent[1] of full-scale	....					

[1] At a minimum, it is required to test at zero-level and at least two other levels across the range of the transmitter or transducer readings corresponding to normal unit operation.
[2] It is required to test at least once at each level.
[3] Use the same units of measure for all readings (e.g., use degrees (°), inches of water (in H_2O), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

(b) When accuracy testing of the orifice, nozzle, or venturi meter is performed according to section 2.1.5.2 of this appendix, record the information displayed in Table D–1 in this section. At a minimum, record the overall flowmeter accuracy results for the fuel flowmeter at the three flow rate levels specified in section 2.1.5.2 of this appendix.

(c) Report the results of all fuel flowmeter accuracy tests, transmitter or transducer accuracy tests, and primary element inspections, as applicable, in the emissions report for the quarter in which the quality assurance tests are performed, using the electronic format specified by the Administrator under §75.64.

2.1.6.3 Failure of Transducer(s) or Transmitter(s)

If, during a transmitter or transducer accuracy test conducted according to section 2.1.6.1 of this appendix, the flowmeter accuracy specification of 2.0 percent is not met at any of the levels tested, repair or replace transmitter(s) or transducer(s) as necessary until the flowmeter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels, to ensure that the flowmeter accuracy specification is met at each level). The fuel flowmeter is ''out-of-control'' and data from the flowmeter are considered invalid, beginning with the date and hour of the failed accuracy test and continuing until the date and hour of completion of a successful transmitter or transducer accuracy test at all levels. In addition, if, during normal operation of the fuel flowmeter, one or more transmitters or transducers malfunction, data from the fuel flowmeter shall be considered invalid from the hour of the transmitter or transducer failure until the hour of completion of a successful 3-level transmitter or transducer accuracy test. During fuel flowmeter out-of-control periods, provide data from another fuel flowmeter that meets the requirements of §75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix. Record and report test data and results, consistent with sections 2.1.6.1 and 2.1.6.2 of this appendix and §75.56 or §75.59, as applicable.

2.1.6.4 Primary Element Inspection

(a) Conduct a visual inspection of the orifice, nozzle, or venturi meter at least once every twelve calendar quarters. Notwithstanding this requirement, the procedures of section 2.1.7 of this appendix may be used to reduce the inspection frequency of the orifice, nozzle, or venturi meter to at least once every twenty calendar quarters. The inspection may be performed using a baroscope. If the visual inspection indicates that the orifice, nozzle, or venturi meter has become damaged or corroded, then:

(1) Replace the primary element with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under §75.6);

(2) Replace the primary element with another primary element, and demonstrate that the overall flowmeter accuracy meets the accuracy specification in section 2.1.5 of this appendix under the procedures of section 2.1.5.2 of this appendix; or

(3) Restore the damaged or corroded primary element to ''as new'' condition; determine the overall accuracy of the flowmeter, using either the specifications of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under §75.6); and retest the transmitters or transducers prior to providing quality assured data from the flowmeter.

(b) If the primary element size is changed, calibrate the transmitter or transducers consistent with the new primary element size. Data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed visual inspection and continuing until the date and hour when:

(1) The damaged or corroded primary element is replaced with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under §75.6);

(2) The damaged or corroded primary element is replaced, and the overall accuracy of the flowmeter is demonstrated to meet the accuracy specification in section 2.1.5 of this appendix under the procedures of section 2.1.5.2 of this appendix; or

(3) The restored primary element is installed to meet the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under §75.6) and its transmitters or transducers are retested to meet the accuracy specification in section 2.1.6.1 of this appendix.

(c) During this period, provide data from another fuel flowmeter that meets the requirements of §75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix.

2.1.7 Fuel Flow-to-Load Quality Assurance Testing for Certified Fuel Flowmeters

The procedures of this section may be used as an optional supplement to the quality assurance procedures in section 2.1.5.1, 2.1.5.2, 2.1.6.1, or 2.1.6.4 of this appendix when conducting periodic quality assurance testing of a certified fuel flowmeter. Note, however, that these procedures may not be used unless the 168-hour baseline data requirement of section 2.1.7.1 of this appendix has been met. If, following a flowmeter accuracy test or flowmeter transmitter test and primary element inspection, where applicable, the procedures of this section are performed during each subsequent fuel flowmeter QA operating quarter, as defined in §72.2 of this chapter (excluding the quarter(s) in which the baseline data are collected), then these procedures may be used to meet the requirement for periodic quality assurance for a period of up to 20 calendar quarters from the previous periodic quality assurance procedure(s) performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 through 2.1.6.4 of this appendix. The procedures of this section are not required for any quarter in which a flowmeter accuracy test or a transmitter accuracy test and a primary element inspection, where applicable, are conducted. Notwithstanding the requirements of §75.54(a) or §75.57(a), as applicable, when using the procedures of this section, keep records of the test data and results from the previous flowmeter accuracy test under section 2.1.5.1 or 2.1.5.2 of this appendix, records of the test data and results from the previous transmitter or transducer accuracy test under section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters, and records of the previous visual inspection of the primary element required under section 2.1.6.4 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters until the next flowmeter accuracy test, transmitter accuracy test, or visual inspection is performed, even if the previous flowmeter accuracy test, transmitter accuracy test, or visual inspection was performed more than three years previously.

2.1.7.1 Baseline Flow Rate-to-Load Ratio or Heat Input-to-Load Ratio

(a) Determine R_{base}, the baseline value of the ratio of fuel flow rate to unit load, following each successful periodic quality assurance procedure performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 and 2.1.6.4 of this appendix. Establish a baseline period of data consisting, at a minimum, of 168 hours of quality assured fuel flowmeter data. Baseline data collection shall begin with the first hour of fuel flowmeter operation following completion of the most recent quality assurance procedure(s), during which only the fuel measured by the fuel flowmeter is combusted (i.e., only gas, only residual oil, or only diesel fuel is combusted by the unit). During the baseline data collection period, the owner or operator may exclude as non-representative any hour in which the unit is ‘‘ramping’’ up or down, (i.e., the load during the hour differs by more than 15.0 percent from the load in the previous or subsequent hour) and may exclude any hour in which the unit load is in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in this lower 25.0 percent of the range is considered normal for the unit). The baseline data must be obtained no later than the end of the fourth calendar quarter following the calendar quarter of the most recent quality assurance procedure for that fuel flowmeter. For orifice-, nozzle-, and venturi-type fuel flowmeters, if the fuel flow-to-load ratio is to be used as a supplement both to the transmitter accuracy test under section 2.1.6.1 of this appendix and to primary element inspections under section 2.1.6.4 of this appendix, then the baseline data must be obtained after both procedures are completed and no later than the end of the fourth calendar quarter following the calendar quarter of both the most recent transmitter or transducer test and the most recent primary element inspection for that fuel flowmeter. From these 168 (or more) hours of baseline data, calculate the baseline fuel flow rate-to-load ratio as follows:

$$R_{base} = \frac{Q_{base}}{L_{avg}} \qquad \text{(Eq. D-1b)}$$

where:

R_{base} = Value of the fuel flow rate-to-load ratio during the baseline period; 100 scfh/MWe or 100 scfh/klb per hour steam load for gas-firing; (lb/hr)/MWe or (lb/hr)/klb per hour steam load for oil-firing.

Q_{base} = Average fuel flow rate measured by the fuel flowmeter during the baseline period, 100 scfh for gas-firing and lb/hr for oil-firing.

L_{avg} = Average unit load during the baseline period, megawatts or 1000 lb/hr of steam.

(b) In Equation D–1b, for a common pipe header, L_{avg} is the sum of the operating loads of all units that receive fuel through the common pipe header. For a unit that receives its fuel through multiple pipes, Q_{base} is the sum of the fuel flow rates for a particular fuel (i.e., gas, diesel fuel, or residual oil) from each of the pipes. Round off the value of R_{base} to the nearest tenth.

(c) Alternatively, a baseline value of the gross heat rate (GHR) may be determined in lieu of R_{base}. The baseline value of the GHR, GHR_{base}, shall be determined as follows:

$$(GHR)_{base} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000 \qquad \text{(Eq. D-1c)}$$

Where:

$(GHR)_{base}$ = Baseline value of the gross heat rate during the baseline period, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_{avg}$ = Average (mean) hourly heat input rate recorded by the fuel flowmeter during the baseline period, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

L_{avg} = Average (mean) unit load during the baseline period, megawatts or 1000 lb/hr of steam.

(d) Report the current value of R_{base} (or GHR_{base}) and the completion date of the associated quality assurance procedure in each electronic quarterly report required under §75.64.

2.1.7.2 Data Preparation and Analysis

(a) Evaluate the fuel flow rate-to-load ratio (or GHR) for each fuel flowmeter QA operating quarter, as defined in §72.2 of this chapter. At the end of each fuel flowmeter QA operating quarter, use Equation D–1d in this appendix to calculate R_h, the hourly fuel flow-to-load ratio, for every quality assured hourly average fuel flow rate obtained with a certified fuel flowmeter.

$$R_h = \frac{Q_h}{L_h} \qquad \text{(Eq. D-1d)}$$

where:

R_h = Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, or (lb/hr)/1000 lb/hr of steam load.

Q_h = Hourly fuel flow rate, as measured by the fuel flowmeter, 100 scfh for gas-firing or lb/hr for oil-firing.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam.

(b) For a common pipe header, L_h shall be the sum of the hourly operating loads of all units that receive fuel through the common pipe header. For a unit that receives its fuel through multiple pipes, Q_h will be the sum of the fuel flow rates for a particular fuel (i.e., gas, diesel fuel, or residual oil) from each of the pipes. Round off each value of R_h to the nearest tenth.

(c) Alternatively, calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000 \qquad \text{(Eq. D-1e)}$$

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_h$ = Hourly heat input rate, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam.

(d) Evaluate the calculated flow rate-to-load ratios (or gross heat rates) as follows. Perform a separate data analysis for each fuel flowmeter following the procedures of this section. Base each analysis on a minimum of 168 hours of data. If, for a particular fuel flowmeter, fewer than 168 hourly flow-to-load ratios (or GHR values) are available, a flow-to-load (or GHR) evaluation is not required for that flowmeter for that calendar quarter.

(e) For each hourly flow-to-load ratio or GHR value, calculate the percentage difference (percent D_h) from the baseline fuel flow-to-load ratio using Equation D–1f.

$$\%D_h = \frac{|R_{base} - R_h|}{R_{base}} \times 100 \qquad \text{(Eq. D-1f)}$$

Where:

$\%D_h$ = Absolute value of the percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

R_h = The hourly fuel flow rate-to-load ratio (or GHR).

R_{base} = The value of the fuel flow rate-to-load ratio (or GHR) from the baseline period, determined in accordance with section 2.1.7.1 of this appendix.

(f) Consistently use R_{base} and R_h in Equation D–1f if the fuel flow-to-load ratio is being evaluated, and consistently use

$(GHR)_{base}$ and $(GHR)_h$ in Equation D–1f if the gross heat rate is being evaluated.

(g) Next, determine the arithmetic average of all of the hourly percent difference (percent D_h) values using Equation D–1g, as follows:

$$E_f = \sum_{h=1}^{q} \frac{\%D_h}{q} \qquad \text{(Eq. D-1g)}$$

Where:

E_f = Quarterly average percentage difference between hourly flow rate-to-load ratios and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

$\%D_h$ = Percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

q = Number of hours used in fuel flow-to-load (or GHR) evaluation.

(h) When the quarterly average load value used in the data analysis is greater than 50 MWe (or 500 klb steam per hour), the results of a quarterly fuel flow rate-to-load (or GHR) evaluation are acceptable and no further action is required if the quarterly average percentage difference (E_f) is no greater than 10.0 percent. When the arithmetic average of the hourly load values used in the data analysis is ≤50 MWe (or 500 klb steam per hour), the results of the analysis are acceptable if the value of E_f is no greater than 15.0 percent.

2.1.7.3 Optional Data Exclusions

(a) If E_f is outside the limits in section 2.1.7.2 of this appendix, the owner or operator may re-examine the hourly fuel flow rate-to-load ratios (or GHRs) that were used for the data analysis and identify and exclude fuel flow-to-load ratios or GHR values for any non-representative fuel flow-to-load ratios or GHR values. Specifically, the R_h or $(GHR)_h$ values for the following hours may be considered non-representative: any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; or any hour for which the load differed by more than ±15.0 percent from the load during either the preceding hour or the subsequent hour; or any hour for which the unit load was in the lower 25.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part (unless operation in the lower 25.0 percent of the range is considered normal for the unit).

(b) After identifying and excluding all non-representative hourly fuel flow-to-load ratios or GHR values, analyze the quarterly fuel flow rate-to-load data a second time.

2.1.7.4 Consequences of Failed Fuel Flow-to-Load Ratio Test

(a) If E_f is outside the applicable limit in section 2.1.7.2 of this appendix (after analysis using any optional data exclusions under section 2.1.7.3 of this appendix), perform transmitter accuracy tests according to section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type flowmeters, or perform a fuel flowmeter accuracy test, in accordance with section 2.1.5.1 or 2.1.5.2 of this appendix, for each fuel flowmeter for which E_f is outside of the applicable limit. In addition, for an orifice-, nozzle-, or venturi-type fuel flowmeter, repeat the fuel flow-to-load ratio comparison of section 2.1.7.2 of this appendix using six to twelve hours of data following a passed transmitter accuracy test in order to verify that no significant corrosion has affected the primary element. If, for the abbreviated 6-to-12 hour test, the orifice-, nozzle-, or venturi-type fuel flowmeter is not able to meet the limit in section 2.1.7.2 of this appendix, then perform a visual inspection of the primary element according to section 2.1.6.4 of this appendix, and repair or replace the primary element, as necessary.

(b) Substitute for fuel flow rate, for any hour when that fuel is combusted, using the missing data procedures in section 2.4.2 of this appendix, beginning with the first hour of the calendar quarter following the quarter for which E_f was found to be outside the applicable limit and continuing until quality assured fuel flow data become available. Following a failed flow rate-to-load or GHR evaluation, data from the flowmeter shall not be considered quality assured until the hour in which all required flowmeter accuracy tests, transmitter accuracy tests, visual inspections and diagnostic tests have been passed. Additionally, a new value of R_{base} or $(GHR)_{base}$ shall be established no later than two flowmeter QA operating quarters after the quarter in which the required quality assurance tests are completed (note that for orifice-, nozzle-, or venturi-type fuel flowmeters, establish a new value of R_{base} or $(GHR)_{base}$ only if both a transmitter accuracy test and a primary element inspection have been performed).

2.1.7.5 Test Results

Report the results of each quarterly flow rate-to-load (or GHR) evaluation, as determined from Equation D–1g, in the electronic quarterly report required under §75.64. Table D–3 is provided as a reference on the type of information to be recorded under §75.59 and reported under §75.64.

TABLE D–3.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST

Plant name:__________________State:_____ORIS code:__________________

TABLE D–3.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST—Continued

Unit/pipe ID #:___________Fuel flowmeter component and system ID #s:_______-_______Calendar quarter (1st, 2nd, 3rd, 4th) and year:___________
Range of operation:___________ to ___________ MWe or klb steam/hr (indicate units)

Time period	
Baseline period	Quarter
Completion date and time of most recent primary element inspection (orifice-, nozzle-, and venturi-type flowmeters only). ___/___/___ ___:___	Number of hours excluded from quarterly average due to co-firing different fuels:_______ hrs.
Completion date and time of the most recent flowmeter or transmitter accuracy test ___/___/___ ___:___	Number of hours excluded from quarterly average due to ramping load: _______ hrs.
Beginning date and time of baseline period ___/___/___ ___:___	Number of hours in the lower 25.0 percent of the range of operation excluded from quarterly average: _______ hrs.
End date and time of baseline period ___/___/___ ___:___	Number of hours included in quarterly average: _______ hrs.
Average fuel flow rate__________________ (100 scfh for gas and lb/hr for oil)	Quarterly percentage difference between hourly ratios and baseline ratio: _______ percent.
Average load;__________________ (MWe or 1000 lb steam/hr)	Test result: pass, fail.
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:_______	
Number of hours in the lower 25.0 percent of the range of operation excluded from baseline ration or GHR: _______ hrs.	

2.2 Oil Sampling and Analysis

Perform sampling and analysis of oil to determine the following fuel properties for each type of oil combusted by a unit: percentage of sulfur by weight in the oil; gross calorific value (GCV) of the oil; and, if necessary, the density of the oil. Use the sulfur content, density, and gross calorific value, determined under the provisions of this section, to calculate SO_2 mass emission rate and heat input rate for each fuel using the applicable procedures of section 3 of this appendix. The designated representative may petition for reduced GCV and or density sampling under §75.66 if the fuel combusted has a consistent and relatively non-variable GCV or density.

TABLE D–4—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	1. Highest sulfur content from previous 30 daily samples; or 2. Actual daily value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year; or 3. Maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year; or 2. Maximum value allowed by contract.[1]
Oil Density	Daily manual sampling	1. Use the highest density from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.

TABLE D–4—OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS—Continued

Parameter	Sampling technique/frequency	Value used in calculations
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year; or 3. Maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year; or 2. Maximum value allowed by contract.[1]
Oil GCV	Daily manual sampling	1. Highest fuel GCV from the previous 30 daily samples; or 2. Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	1. Actual measured value; or 2. Highest of all sampled values in previous calendar year; or 3. Maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	1. Highest of all sampled values in previous calendar year; or 2. 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, use one of the following methods to sample the oil (see Table D–4): sample 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; or sample 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; or use the flow proportional sampling methodology in section 2.2.3 of this appendix; or use 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 (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through pipeline, etc.). A storage tank is a container at a plant holding oil that is actually combusted by the unit, such that no 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 hrs). Use the actual sulfur content (and where density data are required, the actual density) from the composite sample to calculate the hourly SO_2 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). Use either the actual daily sulfur content or the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples for the purpose of calculating SO_2 emissions under section 3 of this appendix. Use either the gross calorific value measured from that day's sample or the highest GCV from the previous 30 days' 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. Do not blend additional fuel 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 SO_2 mass emission rate. Calculate heat input rate using the gross calorific value from either:

(a) The most recent oil sample taken or

(b) One of the conservative assumed values described in section 2.2.4.3 of this appendix.

2.2.4.3 Sampling From Each Delivery

(a) Alternatively, an oil sample may be taken from—

(1) The shipment tank or container upon receipt of each lot of fuel oil or

(2) The supplier's storage container which holds the lot of fuel oil. (Note: a supplier need only sample the storage container once for sulfur content, GCV and, where required, the density so long as the fuel sulfur content and GCV do not change and no fuel is added to the supplier's storage container.)

(b) 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.) of a single fuel.

(c) 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, calculate SO_2 mass emission rate using the sulfur content (and where required, the density) from one of the two following values, 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 (this option is allowed for any consistent fuel which comes from a single source whether or not the fuel is supplied under a contractual agreement) or

(2) The maximum value indicated in the contract with the fuel supplier. Continue to use this assumed contract value unless and until the actual sampled sulfur content, density, or gross calorific value of a delivery exceeds the assumed value.

(d) 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 SO_2 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 SO_2 mass emission rate or heat input rate unless and until: it is superseded by a higher value from an oil sample; or it is superseded by a new contract in which case the new contract value becomes the assumed value at the time the fuel specified under the new contract begins to be combusted in the unit; or (if applicable) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

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

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

2.2.7 Analyze oil samples to determine the heat content of the fuel. Determine oil heat content in accordance with ASTM D240–87 (Reapproved 1991), ''Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter,'' ASTM D2382–88, ''Standard Test Method for Heat or Combustion of Hydrocarbon Fuels by Bomb

Calorimeter (High-Precision Method)'', or ASTM D2015–91, ''Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter'' (incorporated by reference under §75.6) or any other procedures listed in section 5.5 of appendix F of this part.

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

2.3 SO_2 Emissions From Combustion of Gaseous Fuels

(a) Account for the hourly SO_2 mass emissions due to combustion of gaseous fuels for each hour when gaseous fuels are combusted by the unit using the procedures in this section.

(b) The procedures in sections 2.3.1 and 2.3.2 of this appendix, respectively, may be used to determine SO_2 mass emissions from combustion of pipeline natural gas and natural gas, as defined in §72.2 of this chapter. The procedures in section 2.3.3 of this appendix may be used to account for SO_2 mass emissions from any gaseous fuel combusted by a unit. For each type of gaseous fuel, the appropriate sampling frequency and the sulfur content and GCV values used for calculations of SO_2 mass emission rates are summarized in the following Table D–5.

TABLE D–5—GAS SULFUR AND GCV VALUES USED IN CALCULATIONS FOR VARIOUS FUEL TYPES

Parameter	Fuel type and sampling frequency	Value used in calculations
Gas Sulfur Content.	Pipeline Natural Gas with H_2S content less than or equal to 0.3 grains/100scf when using the provisions of section 2.3.1 to determine SO_2 mass emissions.	0.0006 lb/mmBtu.
	Natural Gas with H_2S content less than or equal to 1.0 grain/100scf when using the provisions of section 2.3.2 to determine SO_2 mass emissions.	Default SO_2 emission rate calculated from Eq. D–1h, using either the fuel contract maximum H_2S or the maximum H_2S from historical sampling data.
	Any gaseous fuel delivered in shipments or lots—Sample each lot or shipment.	Actual % sulfur from most recent shipment *or* 1. Highest % sulfur from previous year's samples[1]; or 2. Maximum % sulfur value allowed by contract[1].
	Any gaseous fuel transmitted by pipeline and having a demonstrated ''low sulfur variability'' using the provisions of section 2.3.6—Sample daily.	Actual % sulfur from daily sample; or Highest % sulfur from previous 30 daily samples.
	Any gaseous fuel—Sample hourly	Actual hourly sulfur content of the gas.
Gas GCV ...	Pipeline Natural Gas—Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); or 2. Maximum GCV from contract[1]; *or* 3. Highest GCV from previous year's samples.[1]
	Natural Gas—Sample monthly	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); or 2. Maximum GCV from contract[1]; *or* 3. Highest GCV from previous year's samples.[1]
	Any gaseous fuel delivered in shipments or lots—Sample each lot or shipment.	Actual GCV from most recent shipment or lot *or* 1. Highest GCV from previous year's samples1; or 2. Maximum GCV value allowed by contract.[1]
	Any gaseous fuel transmitted by pipeline and having a demonstrated ''low GCV variability'' using the provisions of section 2.3.5—Sample monthly.	1. GCV from most recent monthly sample (with ≥ 48 operating hours in the month); or 2. Highest GCV from previous year's samples.[1]
	Any other gaseous fuel not having a ''low GCV variability''—Sample at least daily. (Note that the use of an on- line GCV calorimeter or gas chromatograph is allowed).	Actual daily or hourly GCV of the gas.

[1] Assumed sulfur content and GCV values (i.e., contract values or highest values from previous year) may only continue to be used if the sulfur content or GCV of each sample is no greater than the assumed value used to calculate SO_2 emissions or heat input.

2.3.1 Pipeline Natural Gas Combustion

The owner or operator may determine the SO_2 mass emissions from the combustion of a fuel that meets the definition of pipeline natural gas, in §72.2 of this chapter, using the procedures of this section.

2.3.1.1 SO_2 Emission Rate

For a fuel that meets the definition of pipeline natural gas under §72.2 of this chapter, the owner or operator may determine the SO_2 mass emissions using either a default SO_2 emission rate of 0.0006 lb/mmBtu and the procedures of this section, the procedures in section 2.3.2 for natural gas, or the procedures of section 2.3.3 for any gaseous fuel. For each affected unit using the default rate of 0.0006 lb/mmBtu, the owner or operator must document that the fuel combusted is actually pipeline natural gas, using the procedures in section 2.3.1.4 of this appendix.

2.3.1.2 Hourly Heat Input Rate

Calculate hourly heat input rate, in mmBtu/hr, for a unit combusting pipeline natural gas, using the procedures of section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.1 of this appendix in the calculations.

2.3.1.3 SO_2 Hourly Mass Emission Rate and Hourly Mass Emissions

For pipeline natural gas combustion, calculate the SO2 mass emission rate, in lb/hr, using Equation D–5 in section 3.3.2 of this appendix (when the default SO_2 emission rate is used). Then, use the calculated SO_2 mass emission rate and the unit operating time to determine the hourly SO_2 mass emissions from pipeline natural gas combustion, in lb, using Equation D–12 in section 3.5.1 of this appendix.

2.3.1.4 Documentation That a Fuel Is Pipeline Natural Gas

(a) For pipeline natural gas, provide information in the monitoring plan required under §75.53, demonstrating that the definition of pipeline natural gas in §72.2 of this chapter has been met. The information must demonstrate that the fuel has a hydrogen sulfide content of less than 0.3 grain/100scf. The 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 (minimum of one year of data with samples taken monthly or more frequently);

(3) At least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently;

(4) For fuels delivered in shipments or lots, the sulfur content from all shipments or lots received in a one year period; or

(5) Data from a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

(b) When a 720-hour test is used for initial qualification as pipeline natural gas, the owner or operator is required to continue sampling the fuel for hydrogen sulfide at least once per month for one year after the initial qualification period. The use of the default natural gas SO_2 emission rate under 2.3.1.1 is not allowed if any sample during the one year period has a hydrogen sulfide content greater than 0.3 gr/100 scf.

2.3.2 Natural Gas Combustion

The owner or operator may determine the SO_2 mass emissions from the combustion of a fuel that meets the definition of natural gas, in §72.2 of this chapter, using the procedures of this section.

2.3.2.1 SO_2 Emission Rate

The owner or operator may account for SO_2 emissions either by using a default SO_2 emission rate, as determined under section 2.3.2.1.1 of this appendix, or by daily sampling of the gas sulfur content using the procedures of section 2.3.3 of this appendix. For each affected unit using a default SO_2 emission rate, the owner or operator must provide documentation that the fuel combusted is actually natural gas according to the procedures in section 2.3.2.4 of this appendix.

2.3.2.1.1 In lieu of daily sampling of the sulfur content of the natural gas, an SO_2 default emission rate may be determined using Equation D–1h. Round off the calculated SO_2 default emission rate to the nearest 0.0001 lb/mmBtu.

$$ER = H_2S \times 0.0026 \qquad \text{(Eq. D-1h)}$$

Where:

ER = Default SO_2 emission rate for natural gas combustion, lb/mmBtu.

H_2S = Hydrogen sulfide content of the natural gas, gr/100scf.

2.3.2.1.2 The hydrogen sulfide value used in Equation D–1h may be obtained from one of the following sources of information:

(a) The highest hydrogen sulfide content specified by a purchase contract or by a pipeline transportation contract;

(b) The highest hydrogen sulfide content from a certification of the gas vendor, based on routine vendor sampling and analysis (minimum of one year of data with samples taken monthly or more frequently);

(c) The highest hydrogen sulfide content from at least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently;

(d) For fuels delivered in shipments or lots, the highest hydrogen sulfide content from all shipments or lots received in a one year period; or (5) the highest hydrogen sulfide content measured during a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

2.3.2.2 Hourly Heat Input Rate

Calculate hourly heat input rate for natural gas combustion, in mmBtu/hr, using the procedures in section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.2 of this appendix in the calculations.

2.3.2.3 SO_2 Mass Emission Rate and Hourly Mass Emissions

For natural gas combustion, calculate the SO_2 mass emission rate, in lb/hr, using Equation D–5 in section 3.3.2 of this appendix, when the default SO_2 emission rate is used. Then, use the calculated SO_2 mass emission rate and the unit operating time to determine the hourly SO_2 mass emissions from natural gas combustion, in lb, using Equation D–12 in section 3.5.1 of this appendix.

2.3.2.4 Documentation that a Fuel Is Natural Gas

(a) For natural gas, provide information in the monitoring plan required under §75.53, demonstrating that the definition of natural gas in §72.2 of this chapter has been met. The information must demonstrate that the fuel has a hydrogen sulfide content of less than 1.0 grain/100 scf. 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 transportation contract;

(2) A certification of the gas vendor, based on routine vendor sampling and analysis (minimum of one year of data with samples taken monthly or more frequently);

(3) At least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently;

(4) For fuels delivered in shipments or lots, sulfur content from all shipments or lots received in a one year period; or

(5) Data from a 720-hour demonstration conducted using the procedures of section 2.3.6 of this appendix.

(b) When a 720-hour test is used for initial qualification as natural gas, the owner or operator shall continue sampling the fuel for hydrogen sulfide at least once per month for one year after the initial qualification period. The use of the default natural gas SO_2 emission rate under 2.3.2.1.1 is not allowed if any sample during the one year period has a hydrogen sulfide content greater than 1.0 grain/100 scf.

2.3.3 SO_2 Mass Emissions From Any Gaseous Fuel

The owner or operator of a unit may determine SO_2 mass emissions using this section for any gaseous fuel (including fuels such as refinery gas, landfill gas, digester gas, coke oven gas, blast furnace gas, coal-derived gas, producer gas or any other gas which may have a variable sulfur content).

2.3.3.1 Sulfur Content Determination

2.3.3.1.1 Analyze the total sulfur content of the gaseous fuel in grain/100 scf, at the frequency specified in Table D–5 of this appendix. That is: for fuel delivered in discrete shipments or lots, sample each shipment or lot; for fuel transmitted by pipeline, if a demonstration is provided under section 2.3.6 of this appendix showing that the gaseous fuel has a ''low sulfur variability,'' determine the sulfur content daily using either manual sampling or a gas chromatograph; and for all other gaseous fuels, determine the sulfur content on an hourly basis using a gas chromatograph.

2.3.3.1.2 Use one of the following methods when using manual sampling (as applicable to the type of gas combusted) to determine the sulfur content of the fuel: ASTM D1072–90, ''Standard Test Method for Total Sulfur in Fuel Gases'', ASTM D4468–85 (Reapproved 1989) ''Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Radiometric Colorimetry,'' ASTM D5504–94 ''Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence,'' or ASTM D3246–81 (Reapproved 1987) ''Standard Test Method for Sulfur in Petroleum Gas By Oxidative Microcoulometry'' (incorporated by reference under §75.6).

2.3.3.1.3 The sampling and analysis of daily manual samples may be performed by the owner or operator, an outside laboratory, or the gas supplier. If hourly sampling with a gas chromatograph is required, or a source chooses to use an online gas chromatograph to determine daily fuel sulfur content, the owner or operator shall develop and implement a program to quality assure the data from the gas chromatograph, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.3.3.1.4 Results of all sample analyses must be available no later than thirty calendar days after the sample is taken.

2.3.3.2 SO_2 Mass Emission Rate

Calculate the SO_2 mass emission rate for the gaseous fuel, in lb/hr, using equation D–

4 in section 3.3.1 of this appendix. Use the appropriate sulfur content, in equation D–4, as specified in Table D–5 of this appendix. That is, for fuels delivered by pipeline which demonstrate a low sulfur variability (under section 2.3.6 of this appendix) use either the daily value or the highest value in the previous 30 days or for fuels requiring hourly sulfur content sampling with a gas chromatograph use the actual hourly sulfur content).

2.3.3.3 Hourly Heat Input Rate

Calculate the hourly heat input rate for combustion of the gaseous fuel, using the provisions in section 3.4.1 of this appendix. Use the measured fuel flow rate from section 2.1 of this appendix and the gross calorific value from section 2.3.4.3 of this appendix in the calculations.

2.3.4 Gross Calorific Values for Gaseous Fuels

Determine the GCV of each gaseous fuel at the frequency specified in this section, using one of the following methods: 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'' (incorporated by reference under §75.6 of this part). Use the appropriate GCV value, as specified in section 2.3.4.1, 2.3.4.2 or 2.3.4.3 of this appendix, in the calculation of unit hourly heat input rates.

2.3.4.1 GCV of Pipeline Natural Gas

Determine the GCV of fuel that is pipeline natural gas, as defined in §72.2 of this chapter, at least once per calendar month. For GCV used in calculations use the specifications in Table D–5: either the value from the most recent monthly sample, the highest value specified in a contract or tariff sheet, or the highest value from the previous year. The fuel GCV value from the most recent monthly sample shall be used for any month in which that value is higher than a contract limit. If a unit combusts pipeline natural gas for less than 48 hours during a calendar month, the sampling and analysis requirement for GCV is waived for that calendar month. The preceding waiver is limited by the condition that at least one analysis for GCV must be performed for each quarter the unit operates for any amount of time.

2.3.4.2 GCV of Natural Gas

Determine the GCV of fuel that is natural gas, as defined in §72.2 of this chapter, on a monthly basis, in the same manner as described for pipeline natural gas in section 2.3.4.1 of this appendix.

2.3.4.3 GCV of Other Gaseous Fuels

For gaseous fuels other than natural gas or pipeline natural gas, determine the GCV as specified in section 2.3.4.3.1, 2.3.4.3.2 or 2.3.4.3.3, as applicable.

2.3.4.3.1 For a gaseous fuel that is delivered in discrete shipments or lots, determine the GCV for each shipment or lot. The determination may be made by sampling each delivery or by sampling the supply tank after each delivery. For sampling of each delivery, use the highest GCV in the previous year's samples. For sampling from the tank after each delivery, use either the most recent GCV sample or the highest GCV in the previous year.

2.3.4.3.2 For any gaseous fuel that does not qualify as pipeline natural gas or natural gas and which is not delivered in shipments or lots which performs the required 720 hour test under section 2.3.5 of this appendix, and the results of the test demonstrate that the gaseous fuel has a low GCV variability, determine the GCV at least monthly. In calculations of hourly heat input for a unit, use either the most recent monthly sample or the highest fuel GCV from the previous year's samples.

2.3.4.3.3 For any other gaseous fuel, determine the GCV at least daily and use the actual fuel GCV in calculations of unit hourly heat input. If an online gas chromatograph or on-line calorimeter is used to determine fuel GCV each day, the owner or operator shall develop and implement a program to quality assure the data from the gas chromatograph or on-line calorimeter, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.3.5 Demonstration of Fuel GCV Variability

(a) This demonstration is required of any fuel which does not qualify as pipeline natural gas or natural gas, and is not delivered only in shipments or lots. The demonstration data shall be used to determine whether daily or monthly sampling of the GCV of the gaseous fuel or blend is required.

(b) To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the GCV of the gaseous fuel or blend (in Btu/100 scf). The demonstration data shall be obtained using either: hourly sampling and analysis using the methods in section 2.3.4 to determine GCV of the fuel; an on-line gas chromatograph capable of determining fuel GCV on an hourly basis; or an on-line calorimeter. For gaseous fuel produced by a variable process, the data shall be representative of and include all process operating conditions including seasonal and yearly variations in process which may affect fuel GCV.

(c) The data shall be reduced to hourly averages. The mean GCV value and the standard deviation from the mean shall be calculated from the hourly averages. Specifically, the gaseous fuel is considered to have a low GCV variability, and monthly gas sampling for GCV may be used, if the mean value of the GCV multiplied by 1.075 is greater than the sum of the mean value and one standard deviation. If the gaseous fuel or blend does not meet this requirement, then daily fuel sampling and analysis for GCV, using manual sampling, a gas chromatograph or an on-line calorimeter is required.

2.3.6 Demonstration of Fuel Sulfur Variability

(a) This demonstration is required for any fuel which does not qualify as pipeline natural gas or natural gas and is not delivered in shipments or lots. The results of the demonstration will be used to determine whether daily or hourly sampling for sulfur in the fuel is required. To make this demonstration, proceed as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content (and hydrogen sulfide content, if needed to define a fuel as either pipeline natural gas or natural gas) of the gaseous fuel or blend (in gr/100 scf). The demonstration data shall be obtained using either manual hourly sampling or an on-line gas chromatograph capable of determining fuel total sulfur content (and, if applicable, H_2S content) on an hourly basis. For gaseous fuel produced by a variable process, additional data shall be provided which is representative of all process operating conditions including seasonal or annual variations which may affect fuel sulfur content.

(b) Reduce the data to hourly averages of the total sulfur content (and hydrogen sulfide content, if applicable) of the fuel. Then, calculate the mean value of the total sulfur content and standard deviation in order to determine whether daily sampling of the sulfur content of the gaseous fuel or blend is sufficient or whether hourly sampling with a gas chromatograph is required. Specifically, daily gas sampling and analysis for total sulfur content, using either manual sampling or an online gas chromatograph, shall be sufficient, provided that the standard deviation of the hourly average values from the mean value does not exceed 5.0 grains per 100 scf. If the gaseous fuel or blend does not meet this requirement, then hourly sampling of the fuel with a gas chromatograph and hourly reporting of the average sulfur content of the fuel is required.

2.4 Missing Data Procedures.

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

2.4.1 Missing Data for Oil and Gas Samples

When fuel sulfur content, gross calorific value or, when necessary, density 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, 2.2.5, 2.2.6, 2.2.7, 2.3.3.1, 2.3.3.1.2, or 2.3.4 of this appendix, then substitute the maximum potential sulfur content, density, or gross calorific value of that fuel from Table D–6 of this appendix. Irrespective of which reporting option is selected (i.e., actual value, contract value or highest value from the previous year, the missing data values in Table D–6 shall be reported whenever the results of a required sample of sulfur content, GCV or density is missing or invalid in the current calendar year. The substitute data value(s) shall be used until the next valid sample for the missing parameter(s) is obtained. Note that only actual sample results shall be used to determine the ''highest value from the previous year'' when that reporting option is used; missing data values shall not be used in the determination.

TABLE D–6.—MISSING DATA SUBSTITUTION PROCEDURES FOR SULFUR, DENSITY, AND GROSS CALORIFIC VALUE DATA

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	0.3 gr/100 scf for pipeline natural gas, or 1.0 gr/100 scf for natural gas, or Twice the highest total sulfur content value recorded in the previous 30 days when sampling gaseous fuel daily or hourly.
Gas GCV/Heat Content	1100 Btu/scf for pipeline natural gas, natural gas or landfill gas, or 1500 for butane or refinery gas. 2100 Btu/scf for propane or any 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:

(a) The maximum fuel flow rate the unit is capable of combusting or (b) the maximum flow rate that the flowmeter can measure (i.e, upper range value of flowmeter leading to a unit).

2.4.2.2 For hours where only one fuel is combusted, substitute for each hour in the missing data period the average of the hourly fuel flow rate(s) measured and recorded by the fuel flowmeter (or flowmeters, where fuel is recirculated) at the corresponding operating unit load range recorded for each missing hour during the previous 720 hours during which the unit combusted that same fuel only. Establish load ranges for the unit using the procedures of section 2 in appendix C of this part for missing volumetric flow rate data. If no fuel flow rate data are available at the corresponding load range, use data from the next higher load range where data are available. If no fuel flow rate data are available at either the corresponding load range or a higher load range during any hour of the missing data period for that fuel, substitute the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following: (1) the maximum fuel flow rate the unit is capable of combusting or (2) the maximum flow rate that the flowmeter can measure.

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

3. Calculations

Calculate hourly SO_2 mass emission rate from combustion of oil fuel using the procedures in section 3.1 of this appendix. Calculate hourly SO_2 mass emission rate from combustion of gaseous fuel using the procedures in section 3.3 of this appendix. (Note: the SO_2 mass emission rates in sections 3.1 and 3.3 are calculated such that the rate, when multiplied by unit operating time, yields the hourly SO_2 mass emissions for a particular fuel for the unit.) Calculate hourly heat input rate for both oil and gaseous fuels using the procedures in section 3.4 of this appendix. Calculate total SO_2 mass emissions and heat input for each hour, each quarter and the year to date using the procedures under section 3.5 of this appendix. 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.

3.1 SO_2 Mass Emission Rate Calculation for Oil

3.1.1 Use Equation D–2 to calculate SO_2 mass emission rate per hour (lb/hr):

$$SO2_{\text{rate-oil}} = 2.0 \times OIL_{\text{rate}} \times \frac{\%S_{\text{oil}}}{100.0} \qquad \text{(Eq. D-2)}$$

Where:

$SO_{2\text{rate-oil}}$ = Hourly mass emission rate of SO_2 emitted from combustion of oil, lb/hr.

OIL_{rate} = Mass rate of oil consumed per hr during combustion, lb/hr.

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

2.0 = Ratio of lb SO_2/lb S.

3.1.2 Record the SO_2 mass emission rate from oil for each hour that oil is combusted.

3.2 Mass Flow Rate Calculation for Volumetric Oil Flowmeters

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.

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

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.6 of this appendix, use Equation D–3 to calculate the rate of the mass of oil consumed (in lb/hr):

$$OIL_{rate} = V_{oil\text{-}rate} \times D_{oil} \qquad \text{(Eq. D-3)}$$

Where:

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

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

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

3.3 SO_2 Mass Emission Rate Calculation for Gaseous Fuels

3.3.1 Use Equation D–4 to calculate the SO_2 mass emission rate when using the optional gas sampling and analysis procedures in sections 2.3.1 and 2.3.2 of this appendix, or the required gas sampling and analysis procedures in section 2.3.3 of this appendix. Total sulfur content of a fuel must be determined using the procedures of 2.3.3.1.2 of this appendix:

$$SO2_{rate\text{-}gas} = \left(\frac{2}{7000}\right) \times GAS_{rate} \times S_{gas} \qquad \text{(Eq. D-4)}$$

Where:

$SO_{2rate\text{-}gas}$ = Hourly mass rate of SO_2 emitted due to combustion of gaseous fuel, lb/hr.

GAS_{rate} = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.

S_{gas} = Sulfur content of gaseous fuel, in grain/100 scf.

2.0 = Ratio of lb SO_2/lb S.

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

HI_{rate} = Hourly heat input rate of a gaseous fuel, calculated using procedures in section 3.4.1 of this appendix, in mmBtu/hr.

3.3.2 Use Equation D–5 to calculate the SO_2 mass emission rate when using a default emission rate from section 2.3.1.1 or 2.3.2.1.1 of this appendix:

$$SO2_{rate} = ER \times HI_{rate} \qquad \text{(Eq. D-5)}$$

where:

SO_2rate = Hourly mass emission rate of SO_2 from combustion of a gaseous fuel, lb/hr.

ER = SO_2 emission rate from section 2.3.1.1 or 2.3.2.1.1, of this appendix, lb/mmBtu.

3.3.3 Record the SO_2 mass emission rate for each hour when the unit combusts a gaseous fuel.

3.4 Calculation of Heat Input Rate

3.4.1 Heat Input Rate for Gaseous Fuels

(a) Determine total hourly gas flow or average hourly gas flow rate with a fuel flowmeter in accordance with the requirements of section 2.1 of this appendix and the fuel GCV in accordance with the requirements of section 2.3.4 of this appendix. If necessary perform the 720-hour test under section 2.3.5 to determine the appropriate fuel GCV sampling frequency.

(b) Then, use Equation D–6 to calculate heat input rate from gaseous fuels for each hour.

$$HI_{rate\text{-}gas} = \frac{GAS_{rate} \times GCV_{gas}}{10^6} \qquad \text{(Eq. D-6)}$$

Where:

$HI_{rate\text{-}gas}$ = Hourly heat input rate from combustion of the gaseous fuel, mmBtu/hr.

GAS_{rate} = Average volumetric flow rate of fuel, for the portion of the hour in which the unit operated, 100 scf/hr.

GCV_{gas} = Gross calorific value of gaseous fuel, Btu/hr.

10^6 = Conversion of Btu to mmBtu.

(c) Note that when fuel flow is measured on an hourly totalized basis (e.g. a fuel flowmeter reports totalized fuel flow for each hour), before Equation D–6 can be used, the total hourly fuel usage must be converted from units of 100 scf to units of 100 scf/hr using Equation D–7:

$$GAS_{rate} = \frac{GAS_{unit}}{t} \qquad \text{(Eq. D-7)}$$

Where:

GAS_{rate} = Average volumetric flow rate of fuel for the portion of the hour in which the unit operated, 100 scf/hr.

GAS_{unit} = Total fuel combusted during the hour, 100 scf.

t = 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).

3.4.2 Heat Input Rate From the Combustion of Oil

(a) Determine total hourly oil flow or average hourly oil flow rate with a fuel flowmeter, in accordance with the requirements of section 2.1 of this appendix. Determine oil GCV according to the requirements of section 2.2 of this appendix.

Then, use Equation D–8 to calculate hourly heat input rate from oil for each hour:

$$HI_{rate\text{-}oil} = OIL_{rate} \frac{GCV_{oil}}{10^6} \qquad \text{(Eq. D-8)}$$

Where:

$HI_{rate\text{-}oil}$ = Hourly heat input rate from combustion of oil, mmBtu/hr.

OIL_{rate} = Mass rate of oil consumed per hour, as determined using procedures in section 3.2.3 of this appendix, in lb/hr, tons/hr, or kg/hr.

GCV_{oil} = Gross calorific value of oil, Btu/lb, Btu/ton, Btu/kg.

10^6 = Conversion of Btu to mmBtu.

(b) Note that when fuel flow is measured on an hourly totalized basis (e.g., a fuel flowmeter reports totalized fuel flow for each hour), before equation D–8 can be used, the total hourly fuel usage must be converted from units of lb to units of lb/hr, using equation D–9:

$$OIL_{rate} = \frac{OIL_{unit}}{t} \qquad \text{(Eq. D-9)}$$

Where:

OIL_{rate} = Average fuel flow rate for the portion of the hour which the unit operated in lb/hr.

OIL_{unit} = Total fuel combusted during the hour, lb.

t = 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).

3.4.3 Apportioning Heat Input Rate to Multiple Units

(a) Use the procedure in this section to apportion hourly heat input rate to two or more units using a single fuel flowmeter which supplies fuel to the units. (This procedure is not applicable to units calculating NO_X mass emissions using the provisions of subpart H of this part.) The designated representative may also petition the Administrator under § 75.66 to use this apportionment procedure to calculate SO_2 and CO_2 mass emissions.

(b) Determine total hourly fuel flow or flow rate through the fuel flowmeter supplying gas or oil fuel to the units. Convert fuel flow rates to units of 100 scf for gaseous fuels or to lb for oil, using the procedures of this appendix. Apportion the fuel to each unit separately based on hourly output of the unit in MW_e or 1000 lb of steam/hr (klb/hr) using Equation D–10 or D–11, as applicable:

$$GAS_{unit} = GAS_{meter} \left(\frac{U_{output}}{\sum_{\text{all-units}} U_{output}} \right) \qquad \text{(Eq. D-10)}$$

Where:

GAS_{unit} = Gas flow apportioned to a unit, 100 scf.

GAS_{meter} = Total gas flow through the fuel flowmeter, 100 scf.

U_{output} = Total unit output, MW or klb/hr.

$$OIL_{unit} = OIL_{meter}\left(\frac{U_{output}}{\sum_{all\text{-}units} U_{output}}\right) \quad \text{(Eq. D-11)}$$

Where:

OIL_{unit} = Oil flow apportioned to a unit, lb.

OIL_{meter} = Total oil flow through the fuel flowmeter, lb.

U_{output} = Total unit output in either MW_e or klb/hr.

(c) Use the total apportioned fuel flow calculated from Equation D–10 or D–11 to calculate the hourly unit heat input rate, using Equations D–6 and D–7 (for gas) or Equations D–8 and D–9 (for oil).

3.5 Conversion of Hourly Rates to Hourly, Quarterly and Year to Date Totals

3.5.1 Hourly SO_2 Mass Emissions From the Combustion of All Fuels

Determine the total mass emissions for each hour from the combustion of all fuels using Equation D–12:

$$M_{SO2\text{-}hr} = \sum_{all\text{-}fuels} SO2_{rate\text{-}i}\, t_i \quad \text{(Eq. D-12)}$$

Where:

$M_{SO2\text{-}hr}$ = Total mass of SO_2 emissions from all fuels combusted during the hour, lb.

$SO_{2rate\text{-}i}$ = SO_2 mass emission rate for each type of gas or oil fuel combusted during the hour, lb/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), 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).

3.5.2 Quarterly Total SO_2 Mass Emissions

Sum the hourly SO_2 mass emissions in lb as determined from Equation D–12 for all hours in a quarter using Equation D–13:

$$M_{SO2\text{-}qtr} = \frac{1}{2000} \sum_{all\text{-}hours\text{-}in\text{-}qtr} M_{SO2\text{-}hr} \quad \text{(Eq. D-13)}$$

Where:

$M_{SO2\text{-}qtr}$ = Total mass of SO_2 emissions from all fuels combusted during the quarter, tons.

$M_{SO2\text{-}hr}$ = Hourly SO_2 mass emissions determined using Equation D–12, lb.

2000= Conversion factor from lb to tons.

3.5.3 Year to Date SO_2 Mass Emissions

Calculate and record SO_2 mass emissions in the year to date using Equation D–14:

$$M_{SO2\text{-}YTD} = \sum_{q=1}^{current\text{-}quarter} M_{SO2\text{-}qtr} \quad \text{(Eq. D-14)}$$

Where:

$M_{SO2\text{-}YTD}$ = Total SO_2 mass emissions for the year to date, tons.

$M_{SO2\text{-}qtr}$ = Total SO_2 mass emissions for the quarter, tons.

3.5.4 Hourly Total Heat Input from the Combustion of all Fuels

Determine the total heat input in mmBtu for each hour from the combustion of all fuels using Equation D–15:

$$HI_{hr} = \sum_{all\text{-}fuels} HI_{rate\text{-}i}\, t_i \quad \text{(Eq. D-15)}$$

Where:

HI_{hr} = Total heat input from all fuels combusted during the hour, mmBtu.

$HI_{rate\text{-}i}$ =Heat input rate for each type of gas or oil combusted during the hour, mmBtu/hr.

t_i = Time each gas or oil fuel was combusted for the hour (fuel usage time), 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).

3.5.5 Quarterly Heat Input

Sum the hourly heat input values determined from equation D–15 for all hours in a quarter using Equation D–16:

$$HI_{qtr} = \frac{1}{2000} \sum_{\text{all-hours-in-qtr}} HI_{hr} \qquad \text{(Eq. D-16)}$$

Where:

HI_{qtr} = Total heat input from all fuels combusted during the quarter, mmBtu.
HI_{hr} = Hourly heat input determined using Equation D–15, mmBtu.

3.5.6 Year-to-Date Heat Input

Calculate and record the total heat input in the year to date using Equation D–17.

$$HI_{YTD} = \sum_{q=1}^{\text{current-quarter}} HI_{qtr} \qquad \text{(Eq. D-17)}$$

HI_{YTD} = Total heat input for the year to date, mmBtu.
HI_{qtr} = Total heat input for the quarter, mmBtu.

3.6 Records and Reports

Calculate and record quarterly and cumulative SO_2 mass emissions and heat input for each calendar quarter using the procedures and equations of section 3.5 of this appendix. Calculate and record SO_2 emissions and heat input data using a data acquisition and handling system. Report these data in a standard electronic format specified by the Administrator.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26548, 26551, May 17, 1995; 61 FR 25585, May 22, 1996; 61 FR 59166, Nov. 20, 1996; 63 FR 57513, Oct. 27, 1998; 64 FR 28652–28663, May 26, 1999]

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

1. APPLICABILITY

1.1 Unit Operation Requirements

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

1.2 Certification

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

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

2. PROCEDURE

2.1 Initial Performance Testing

Use the following procedures for: measuring NO_X emission rates at heat input rate levels corresponding to different load levels; measuring heat input rate; and plotting the correlation between heat input rate and NO_X emission rate, in order to determine the emission rate of the unit(s).

2.1.1 LOAD SELECTION

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

2.1.2 NO_X AND O_2 CONCENTRATION MEASUREMENTS

Use the following procedures to measure NO_X and O_2 concentration in order to determine NO_X emission rate.