2.1c Small Industrial-Commercial-Institutional Steam Generating Units (NSPS)

2.1.1c Applicability

(a) The affected facility to which this source category applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) [100 million BTU per hour (BTU/hr)] or less but greater than or equal to 2.9 MW (10 million BTU/hr).

2.1.2c Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

(a) Except as provided in paragraphs (g) and (h) of this section and in §1.2(b), performance tests required under §1.2 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. §1.2(f) does not apply to this section. The 30-day notice required in §1.2(d) applies only to the initial performance test unless otherwise specified by the Director.

(b) The initial performance test required under §1.2 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under §60.42c* shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) and §1.2, compliance with the percent reduction requirements and SO_2 emission limits under §60.42c* is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS). Method 19 shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} ($E_{ho}°$) is used in Equation 19-19 of Method 19 to compute the adjusted E_{ao} ($E_{ao}°$). The $E_{ho}°$ is computed using the following formula:

$$E_{ho}^{\circ} = [E_{ho} - E_w (1 - X_k)] / X_k$$

where:

E_{ho}° is the adjusted E_{ho}, ng/J (lb/million BTU)

E_{ho} is the hourly SO_2 emission rate, ng/J (lb/million BTU)

E_w is the SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19, ng/J (lb/million BTU). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

X_k is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(2) The owner or operator of an affected facility that qualifies under the provisions of §60.42c(c) or (d)* (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19.

(f) Affected facilities subject to the percent reduction requirements under §60.42c(a) or (b)* shall determine compliance with the SO_2 emission limits under §60.42c* pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures.

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100 \left(1 - \%R_g / 100\right)\left(1 - \%R_f / 100\right)$$

where:

$\%P_s$ is the percent of potential SO_2 emission rate, in percent

$\%R_g$ is the SO_2 removal efficiency of the control device as determined by Method 19, in percent

$\%R_f$ is the SO_2 removal efficiency of fuel pretreatment as determined by Method 19, in percent

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures

required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g°$) is computed from $E_{ao}°$ from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate ($E_{ai}°$) using the following formula:

$$\%R_g° = 100\ (1.0 - E_{ao}°/E_{ai}°)$$

where:

$\%R_g°$ is the adjusted $\%R_g$, in percent

$E_{ao}°$ is the adjusted E_{ao}, ng/J (lb/million BTU)

$E_{ai}°$ is the adjusted average SO_2 inlet rate, ng/J (lb/million BTU)

(ii) To compute $E_{ai}°$, an adjusted hourly SO_2 inlet rate ($E_{hi}°$) is used. The $E_{hi}°$ is computed using the following formula:

$$E_{hi}° = [E_{hi} - E_w\ (1 - X_k)]/\ X_k$$

where:

$E_{hi}°$ is the adjusted E_{hi}, ng/J (lb/million BTU)

E_{hi} is the hourly SO_2 inlet rate, ng/J (lb/million BTU)

E_w is the SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19, ng/J (lb/million BTU). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

X_k is the fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c* based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §2.1.4c(d)(2)*.

(h) For affected facilities subject to §60.42c(h)(1), (2), or (3)* where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under §2.1.6c(f)(1), (2), or (3), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under §60.42c(c)(2)* shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under §2.1.4c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

2.1.3c Compliance and Performance Test Methods and Procedures for Particulate Matter

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under §60.43c* shall conduct an initial performance test as required under §1.2, and shall conduct subsequent performance tests as requested by the Director, to determine compliance with the standards using the following procedures and reference methods.

(1) Method 1 shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B shall be used for gas analysis when applying Method 5, Method 5B, or Method 17.

(3) Method 5, Method 5B, or Method 17 shall be used to measure the concentration of PM as follows:

(i) Method 5 may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160°C (320°F). The procedures of Sections 8.1 and 11.1of Method 5B may be used in Method 17 only if Method 17 is used in conjunction with a wet scrubber system. Method 17 shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Director when necessitated by process variables or other factors.

(5) For Method 5 or Method 5B, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ± 14°C (320 ± 25°F).

(6) For determination of PM emissions, an oxygen or carbon dioxide measurement shall be obtained simultaneously with each run of Method 5, Method 5B, or Method 17 by traversing the duct at the same sampling location.

(7) For each run using Method 5, Method 5B, or Method 17, the emission rates expressed in ng/J (lb/million BTU) heat input shall be determined using:

(i) The oxygen or carbon dioxide measurements and PM measurements obtained under this section,

(ii) The dry basis F-factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(8) Method 9 (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under §60.43c(b)(2)* shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

2.1.4c Emission Monitoring for Sulfur Dioxide

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under §60.42c* shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either oxygen or carbon dioxide concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under §60.42c* shall measure SO_2 concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/million BTU heat input and shall be used to calculate the average emission rates under §60.42c*. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation and include at least 2 data points representing two 15-minute periods. Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under Section 1.4 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 (Appendix B).

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 (Appendix F).

(3) For affected facilities subject to the percent reduction requirements under §60.42c*, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of §60.42c*, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according to Method 19. Method 19 provided procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and carbon dioxide measurement train operated at the candidate location and a second similar train operated according to the procedures in §8.1.3 and the applicable procedures in section 8.4 of Performance Specification 2 (Appendix B). Method 6B, Method 6A, or a combination of Methods 6 and 3B or Methods 6C and 3A are suitable measurement techniques. If Method 6B is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to §60.42c(h) (1), (2), or (3)* where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under §2.1.6c(f) (1), (2), or (3), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Director.

2.1.5c Emission Monitoring for Particulate Matter

(a) The owner or operator of an affected facility combusting coal, residual oil, or wood that is subject to the opacity standards under §60.43c* shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

(b) All COMS for measuring opacity shall be operated in accordance with the applicable procedures under Performance Specification 1 (Appendix B). The span value of the opacity COMS shall be between 60 and 80 percent.

2.1.6c Reporting and Recordkeeping Requirements

(a) [Reserved]

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of §60.42c*, or the PM or opacity limits of §60.43c*, shall submit to the Director the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in Appendix B.

(c) The owner or operator of each coal-fired, residual oil-fired, or wood-fired affected facility subject to the opacity limits under §60.43c(c)* shall submit excess emission reports for any excess emissions from the affected facility which occur during the reporting period.

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c* shall submit reports to the Director.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.43c* shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/million BTU), or 30-day average sulfur content (weight content), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 (Appendix B).

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under Appendix F, Procedure 1.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), or (3) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier; and

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c*.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(h) The owner or operator of each affected facility subject to a Federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c* or §60.43c* shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this section is each calendar quarter. All reports shall be submitted to the Director and shall be postmarked by the 30th day following the end of the reporting period.

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*Code of Federal Regulations, Title 40, Part 60.