

**Environmental Protection Agency**

**§ 60.45**

completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain NO<sub>x</sub>, expressed as NO<sub>2</sub> in excess of:

- (1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.
- (2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.
- (3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w (260) + x (86) + y (130) + z (300)}{(w + x + y + z)}$$

Where:

PS<sub>NO<sub>x</sub></sub> = Prorated standard for NO<sub>x</sub> when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = Percentage of total heat input derived from lignite;

x = Percentage of total heat input derived from gaseous fossil fuel;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for NO<sub>x</sub> does not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with §60.44Da(e)(3)

of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in §60.44Da(e)(3) of subpart Da of this part.

**§ 60.45 Emissions and fuel monitoring.**

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) for measuring the opacity of emissions, SO<sub>2</sub> emissions, NO<sub>x</sub> emissions, and either oxygen (O<sub>2</sub>) or carbon dioxide (CO<sub>2</sub>) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that burns only gaseous fossil fuel and that does not use post-combustion technology to reduce emissions of SO<sub>2</sub> or PM, CEMS for measuring the opacity of emissions and SO<sub>2</sub> emissions are not required.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for

measuring SO<sub>2</sub> emissions is not required if the owner or operator monitors SO<sub>2</sub> emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for NO<sub>x</sub> may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of NO<sub>x</sub> are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring NO<sub>x</sub> emissions is not required. If the initial performance test results show that NO<sub>x</sub> emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for NO<sub>x</sub> within one year after the date of the initial performance tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator does not install any CEMS for sulfur oxides and NO<sub>x</sub>, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a CEMS for measuring either O<sub>2</sub> or CO<sub>2</sub> is not required.

(5) An owner or operator may petition the Administrator (in writing) to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.

(6) A CEMS for measuring the opacity of emissions is not required for a fossil fuel-fired steam generator that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO<sub>2</sub>, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (b)(6)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (b)(6) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

**Environmental Protection Agency**

**§ 60.45**

(c) For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of SO<sub>2</sub> and NO<sub>x</sub> continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in §60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Per-

formance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or NO<sub>x</sub> the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, SO<sub>2</sub> and NO<sub>x</sub> span values shall be determined as follows:

Fossil fuel	In parts per million	
	Span value for SO <sub>2</sub>	Span value for NO <sub>x</sub>
Gas .....	(1) .....	500.
Liquid .....	1,000 .....	500.
Solid .....	1,500 .....	1,000.
Combinations .....	1,000y + 1,500z .....	500 (x + y) + 1,000z.

<sup>1</sup> Not applicable.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel;

y = Fraction of total heat input derived from liquid fossil fuel; and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the SO<sub>2</sub> and NO<sub>x</sub> span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous moni-

toring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring O<sub>2</sub> is selected, the measurement of the pollutant concentration and O<sub>2</sub> concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF \left( \frac{20.9}{(20.9 - \%O_2)} \right)$$

Where E, C, F, and %O<sub>2</sub> are determined under paragraph (f) of this section.

(2) When a CEMS for measuring CO<sub>2</sub> is selected, the measurement of the pollutant concentration and CO<sub>2</sub> concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c \left( \frac{100}{\%CO_2} \right)$$

Where E, C, F<sub>c</sub> and %CO<sub>2</sub> are determined under paragraph (f) of this section.

§ 60.45

40 CFR Ch. I (7-1-07 Edition)

(f) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(1)  $E$  = pollutant emissions, ng/J (lb/MMBtu).

(2)  $C$  = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by  $4.15 \times 10^4$  M ng/dscm per ppm ( $2.59 \times 10^{-9}$  M lb/dscf per ppm) where  $M$  = pollutant molecular weight, g/g-mole (lb/lb-mole).  $M$  = 64.07 for  $\text{SO}_2$  and 46.01 for  $\text{NO}_x$ .

(3) % $\text{O}_2$ , % $\text{CO}_2$  =  $\text{O}_2$  or  $\text{CO}_2$  volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4)  $F$ ,  $F_c$  = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted ( $F$ ), and a factor representing a ratio of the volume of  $\text{CO}_2$  generated to the calorific value of the fuel combusted ( $F_c$ ), respectively. Values of  $F$  and  $F_c$  are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see §60.17),  $F = 2,723 \times 10^{-17}$  dscm/J (10,140 dscf/MMBtu) and  $F_c = 0.532 \times 10^{-17}$  scm  $\text{CO}_2$ /J (1,980 scf  $\text{CO}_2$ /MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see §60.17),  $F = 2.637 \times 10^{-7}$  dscm/J (9,820 dscf/MMBtu) and  $F_c = 0.486 \times 10^{-7}$  scm  $\text{CO}_2$ /J (1,810 scf  $\text{CO}_2$ /MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils,  $F = 2.476 \times 10^{-7}$  dscm/J (9,220 dscf/MMBtu) and  $F_c = 0.384 \times 10^{-7}$  scm  $\text{CO}_2$ /J (1,430 scf  $\text{CO}_2$ /MMBtu).

(iv) For gaseous fossil fuels,  $F = 2.347 \times 10^{-7}$  dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels,  $F_c = 0.279 \times 10^{-7}$  scm  $\text{CO}_2$ /J (1,040 scf  $\text{CO}_2$ /MMBtu) for natural gas,  $0.322 \times 10^{-7}$  scm  $\text{CO}_2$ /J (1,200 scf  $\text{CO}_2$ /MMBtu) for propane, and  $0.338 \times 10^{-7}$  scm  $\text{CO}_2$ /J (1,260 scf  $\text{CO}_2$ /MMBtu) for butane.

(v) For bark  $F = 2.589 \times 10^{-7}$  dscm/J (9,640 dscf/MMBtu) and  $F_c = 0.500 \times 10^{-7}$  scm  $\text{CO}_2$ /J (1,840 scf  $\text{CO}_2$ /MMBtu). For wood residue other than bark  $F = 2.492 \times 10^{-7}$  dscm/J (9,280 dscf/MMBtu) and  $F_c = 0.494 \times 10^{-7}$  scm  $\text{CO}_2$ /J (1,860 scf  $\text{CO}_2$ /MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see §60.17),  $F = 2.659 \times 10^{-7}$  dscm/J (9,900 dscf/MMBtu) and  $F_c = 0.516 \times 10^{-7}$  scm  $\text{CO}_2$ /J (1,920 scf  $\text{CO}_2$ /MMBtu).

(5) The owner or operator may use the following equation to determine an  $F$  factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate  $F$  on a wet basis, consult the Administrator) or  $F_c$  factor (scm  $\text{CO}_2$ /J, or scf  $\text{CO}_2$ /MMBtu) on either basis in lieu of the  $F$  or  $F_c$  factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6} \frac{[227.2 (\%H) + 95.5 (\%C) + 35.6 (\%S) + 8.7 (\%N) - 28.7 (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5} (\%C)}{GCV \text{ (SI units)}}$$

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

$$F_c = \frac{20.0 (\%C)}{GCV \text{ (SI units)}}$$

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

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and O<sub>2</sub> (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see §60.17.)

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see §60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F<sub>c</sub> value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F<sub>c</sub> factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

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

Where:

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

F<sub>i</sub> or (F<sub>c</sub>)<sub>i</sub> = Applicable F or F<sub>c</sub> factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and

n = Number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semi-annually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity*. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of §60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity

## § 60.46

of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(2) *Sulfur dioxide*. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO<sub>2</sub> as measured by a CEMS exceed the applicable standard under § 60.43, or

(ii) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of SO<sub>2</sub> as measured by a CEMS exceed the applicable standard under § 60.43. Facilities complying with the 30-day SO<sub>2</sub> standard shall use the most current associated SO<sub>2</sub> compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.

(3) *Nitrogen oxides*. Excess emissions for affected facilities using a CEMS for measuring NO<sub>x</sub> are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44, or

(ii) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of NO<sub>x</sub> as measured by a CEMS exceed the applicable standard under § 60.43. Facilities complying with the 30-day NO<sub>x</sub> standard shall use the most current associated NO<sub>x</sub> compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter*. Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards under § 60.43. Affected facilities using PM CEMS in lieu of a CEMS for

## 40 CFR Ch. I (7-1-07 Edition)

monitoring opacity emissions must follow the most current applicable compliance and monitoring provisions in §§ 60.48Da and 60.49Da of subpart Da of this part.

### § 60.46 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, SO<sub>2</sub>, and NO<sub>x</sub> standards in §§ 60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of PM, SO<sub>2</sub>, or NO<sub>x</sub> shall be computed for each run using the following equation:

$$E = CF_d \left( \frac{20.9}{(20.9 - \%O_2)} \right)$$

Where:

E = Emission rate of pollutant, ng/J (1b/million Btu);

C = Concentration of pollutant, ng/dscm (1b/dscf);

%O<sub>2</sub> = O<sub>2</sub> concentration, percent dry basis; and

F<sub>d</sub> = Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the O<sub>2</sub> concentration (%O<sub>2</sub>).