

## NEW ADDED SUBPART

Re Rules and Regulations of the)  
Air Pollution Control District )  
of San Diego County .....

**RESOLUTION ADDING SUBPART Dc TO REGULATION X  
STANDARD OF PERFORMANCE FOR  
NEW STATIONARY SOURCES (NSPS)  
OF THE RULES AND REGULATIONS OF THE  
SAN DIEGO COUNTY AIR POLLUTION CONTROL DISTRICT**

On motion of Member MacDonald, seconded by Member Golding the following resolution is adopted:

**WHEREAS**, the San Diego County Air Pollution Control Board, pursuant to Section 40702 of the Health and Safety Code, adopted Rules and Regulations of the Air Pollution Control District of San Diego County; and

**WHEREAS**, said Board now desires to amend said Rules and Regulations; and

**WHEREAS**, notice has been given and a public hearing has been had relating to the amendment of said Rules and Regulations pursuant to Section 40725 of the Health and Safety Code.

**NOW THEREFORE IT IS RESOLVED AND ORDERED** by the San Diego County Air Pollution Control Board that the Rules and Regulations of the Air Pollution Control District of San Diego County be and hereby are amended as follows:

New proposed Subpart Dc is added to Regulation X as follows:

**SUBPART Dc - STANDARDS OF PERFORMANCE FOR SMALL  
INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM  
GENERATING UNITS**

**RULE 260.40c. APPLICABILITY AND DELEGATION OF AUTHORITY**

(a) The affected facility to which this subpart 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).

(b) In delegating implementation and enforcement authority to a State under Section 111(c) of the Clean Air Act, Rule 260.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

## **RULE 260.41c. DEFINITIONS**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in Subpart A of this Regulation.

(a) **"Annual Capacity Factor"** means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

(b) **"Coal"** means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials in ASTM D388-77, "Standard Specification for Classification of Coals by Rank;" coal refuse; and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are included in this definition for the purposes of this subpart.

(c) **"Coal Refuse"** means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kj/kg) 6,000 Btu per pound (Btu/lb) on a dry basis.

(d) **"Cogeneration Steam Generating Unit"** means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

(e) **"Combined Cycle System"** means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

(f) **"Conventional Technology"** means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

(g) **"Distillate Oil"** means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing Materials in ASTM D396-78, "Standard Specification for Fuel Oils."

(h) **"Dry Flue Gas Desulfurization Technology"** means a sulfur dioxide (SO<sub>2</sub>) control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

(i) **"Duct Burner"** means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

76. 11 64 8 91 JES

RECEIVED

(j) **"Emerging Technology"** means any SO<sub>2</sub> control system that is not defined as a conventional technology under this rule, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under Rule 260.48c(a)(4).

(k) **"Federally Enforceable"** means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR Parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

(l) **"Fluidized Bed Combustion Technology"** means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

(m) **"Fuel Pretreatment"** means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

(n) **"Heat Input"** means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

(o) **"Heat Transfer Medium"** means any material that is used to transfer heat from one point to another point.

(p) **"Maximum Design Heat Input Capacity"** means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

(q) **"Natural Gas"** means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, "Standard Specification for Liquefied Petroleum Gases."

(r) **"Noncontinental Area"** means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Island.

(s) **"Oil"** means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

(t) **"Potential Sulfur Dioxide Emission Rate"** means the theoretical SO<sub>2</sub> emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

(u) **"Process Heater"** means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

(v) **"Residual Oil"** means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil and all fuel oil number 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396-78, "Standard Specification for Fuel Oils."

(w) **"Steam Generating Unit"** means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

(x) **"Steam Generating Unit Operating Day"** means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

(y) **"Wet Flue Gas Desulfurization Technology"** means an SO<sub>2</sub> control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

(z) **"Wet Scrubber System"** means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter or SO<sub>2</sub>.

(aa) **"Wood"** means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

#### **RULE 260.42c. STANDARD FOR SULFUR DIOXIDE**

(a) Except as provided in Sections (b), (c), and (e) of this rule, on and after the date on which the initial performance test is completed or required to be completed under Rule 260.8 of this Regulation, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: (1) cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 10 percent (0.10) of the potential SO<sub>2</sub> emission rate (90 percent reduction); nor (2) cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 90 percent SO<sub>2</sub> reduction requirement specified in this paragraph and the emission limit is determined pursuant to Subsection (e)(2) of this rule.

(b) Except as provided in Sections (c) and (e) of this rule, on and after the date on which the initial performance test is completed or required to be completed under Rule 260.8 of this Regulation, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 20 percent (0.20) of the potential SO<sub>2</sub> emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 520 ng/J (1.2 lb/million Btu) heat input. If coal is

fired with coal refuse, the affected facility is subject to Section (a) of this rule. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 90 percent SO<sub>2</sub> reduction requirement specified in Section (a) of this rule and the emission limit determined pursuant to Subsection (e)(2) of this rule.

(2) Combusts only coal and that uses an emerging technology for the control of SO<sub>2</sub> emission shall neither:

(i) Cause to be discharged into the atmosphere from the affected facility any gases that contain SO<sub>2</sub> in excess of 50 percent (0.50) of the potential SO<sub>2</sub> emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 260 ng/J (0.60 lb/million Btu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO<sub>2</sub> reduction requirement specified in this paragraph and the emission limit determined pursuant to Subsection (e)(2) of this rule.

(c) On and after the date on which the initial performance test is completed or required to be completed under Rule 260.8 of this Regulation, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in Subsections (c)(1), (2), (3) or (4) of this rule shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of the emission limit determined pursuant to Subsection (e)(2) of this rule. Percent reduction requirements are not applicable to affected facilities under this paragraph.

(1) Affected facilities that have a heat input capacity of 22 MW (75 million Btu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under Rule 260.8 of this Regulation, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of 215 ng/J (0.50 lb/million Btu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under Rule 260.8 of this Regulation, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged in the atmosphere from that affected facility any gases that contain SO<sub>2</sub> in excess of the following:

(1) The percent of potential SO<sub>2</sub> emission rate required under Section (a) or Subsection (b)(2) of this rule, as applicable, for any affected facility that:

- (i) Combusts coal in combination with any other fuel,
- (ii) Has a heat input capacity greater than 22 MW (75 million Btu/hr), and
- (iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil or coal and oil with any other fuel:

$$E_s = (K_a H_a + K_b H_b + K_c H_c) / (H_a + H_b + H_c)$$

where:

$E_s$  is the SO<sub>2</sub> emission limit, expressed in ng/J or lb/million Btu heat input,

$K_a$  is 520 ng/J (1.2 lb/million Btu),

$K_b$  is 260 ng/J (0.60 lb/million Btu),

$K_c$  is 215 ng/J (0.50 lb/million Btu),

$H_a$  is the heat input from the combustion of coal, except coal combusted in an affected facility subject to Subsection (b)(2) of this rule, in Joules (J) (million Btu),

$H_b$  is the heat input from the combustion of coal in an affected facility subject to Subsection (b)(2) of this rule, in J (million Btu),

$H_c$  is the heat input from the combustion of oil, in J (million Btu).

(f) Reduction in the potential SO<sub>2</sub> emission rate through fuel pretreatment is not credited toward the percent reduction requirement under Subsection (b)(2) of this rule unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO<sub>2</sub> emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or postcombustion SO<sub>2</sub> control) are equal to or less than the emission limits specified under Subsection (b)(2) of this rule.

(g) Except as provided in Section (h) of this rule, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this rule shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under Subsections (h)(1), (2), or (3) of this rule, compliance with the emission limits or fuel oil sulfur limits under this rule may be determined based on a certification from the fuel supplier, as described under Rule 260.48c(f)(1), (2) or (3), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 million Btu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 million Btu/hr).

(i) The SO<sub>2</sub> emission limits, fuel oil sulfur limits, and percent reduction requirements under this rule apply at all times, including periods of startup, shutdown, and malfunction.

(j) Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this rule. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

#### **RULE 260.43c. STANDARD FOR PARTICULATE MATTER**

(a) On and after the date on which the initial performance test is completed or required to be completed under Rule 260.8 of this Regulation, whichever date comes first, no owner or operator of an affected facility that combusts coal or combusts mixtures of coal with other fuels and has heat input capacity of 8.7 MW (30 million Btu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of the following emission limits:

(1) 22 ng/J (0.05 lb/million Btu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under Rule 260.8 of this Regulation, whichever date comes first, no owner or operator of an affected facility that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain particulate matter in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/million Btu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/million Btu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under Rule 260.8 of this Regulation, whichever date comes first, no owner or

operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 million Btu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(d) The particulate matter and opacity standards under this rule apply at all times, except during periods of startup, shutdown, or malfunction.

#### **RULE 260.44c. COMPLIANCE AND PERFORMANCE TEST METHODS AND PROCEDURES FOR SULFUR DIOXIDE**

(a) Except as provided in Sections (g) and (h) of this rule and in Rule 260.8(b), performance tests required under Rule 260.8 shall be conducted following the procedures specified in Sections (b), (c), (d), (e), and (f) of this rule, as applicable. Rule 260.8(f) does not apply to this rule. The 30-day notice required in Rule 260.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under Rule 260.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO<sub>2</sub> emission limits under Rule 260.42c 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 Section (b) and Rule 260.8, compliance with the percent reduction requirements and SO<sub>2</sub> emission limits under Rule 260.42c is based on the average percent reduction and the average SO<sub>2</sub> 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<sub>2</sub> 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<sub>2</sub> emission rate ( $E_{ho}$ ) and the 30-day average SO<sub>2</sub> 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  $E_{ho}$  ( $E_{ho}^o$ ) is used in Equation 19-19 of Method 19 to compute the adjusted  $E_{ao}$  ( $E_{ao}^o$ ). The  $E_{ho}^o$  is computed using the following formula:

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

where:

$E_{ho}^o$  is the adjusted  $E_{ho}$ , ng/J (lb/million Btu)

$E_{ho}$  is the hourly SO<sub>2</sub> 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 Rule 260.42c(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 Rule 260.42c(a) or (b) shall determine compliance with the  $SO_2$  emission limits under Rule 260.42c pursuant to Sections (d) or (e) of this rule, 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:

$$\%P_s = 100 (1 - \%R_s/100) (1 - \%R_f/100)$$

where:

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

$\%R_s$  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 Subsection (f)(1) of this rule are used, except as provided for in the following:

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

$$\%R_g^o = 100 [1.0 - E_{ao}^o/E_{ai}^o]$$

where:

$\%R_g^o$  is the adjusted  $\%R_g$  in percent.

$E_{ao}^o$  is the adjusted  $E_{ao}$ , ng/J (lb/million Btu).

$E_{ai}^o$  is the adjusted average  $SO_2$  inlet rate, ng/J (lb/million Btu).

(ii) To compute  $E_{ai}^0$ , an adjusted hourly SO<sub>2</sub> inlet rate ( $E_{hi}^0$ ) is used. The  $E_{hi}^0$  is computed using the following formula:

$$E_{hi}^0 = [E_{hi} - E_w (1 - X_k)] / X_k$$

where:

$E_{hi}^0$  is the adjusted  $E_{hi}$ , ng/J (lb/million Btu)

$E_{hi}$  is the hourly SO<sub>2</sub> inlet rate, ng/J (lb/million Btu)

$E_w$  is the SO<sub>2</sub> 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 Rule 260.42c 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 Rule 260.46c(d)(2).

(h) For affected facilities subject to Rule 260.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO<sub>2</sub> standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described under Rule 260.48c(f)(1), (2), or (3), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO<sub>2</sub> standards under Rule 260.42c(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 averaged 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<sub>2</sub> emissions data in calculating %P<sub>s</sub> and  $E_{ho}$  under Sections (d), (e), or (f) of this rule, as applicable, whether or not the minimum emissions data requirements under Rule 260.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating %P<sub>s</sub> or  $E_{ho}$  pursuant to Sections (d), (e), or (f) of this rule, as applicable.

**RULE 260.45c. COMPLIANCE AND PERFORMANCE TEST METHODS  
AND PROCEDURES FOR PARTICULATE MATTER**

(a) The owner or operator of an affected facility subject to the particulate matter and/or opacity standards under Rule 260.43c shall conduct an initial performance test as required under Rule 260.8, and shall conduct subsequent performance tests as requested by the Control Officer, 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. The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry square cubic meters (dscm) [60 dry square cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Control Officer when necessitated by process variables or other factors.

(2) Method 3 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 particulate matter 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 2.1 and 2.3 of 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) 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°C (320°F).

(5) For determination of particulate matter 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.

(6) 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 particulate matter 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).

(7) 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 particulate matter standards under Rule 260.43c(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.

#### **RULE 260.46c. EMISSION MONITORING FOR SULFUR DIOXIDE**

(a) Except as provided in Sections (d) and (e) of this rule, the owner or operator of an affected facility subject to the SO<sub>2</sub> emission limits under Rule 260.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO<sub>2</sub> concentrations and either oxygen or carbon dioxide concentrations at the outlet of the SO<sub>2</sub> control device (or the outlet of the steam generating unit if no SO<sub>2</sub> 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 Rule 260.42c shall measure SO<sub>2</sub> concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO<sub>2</sub> control device.

(b) The 1-hour average SO<sub>2</sub> 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 Rule 260.42c. Each 1-hour average SO<sub>2</sub> 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<sub>2</sub> 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 Rule 260.13 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 Rule 260.42c, the span value of the SO<sub>2</sub> CEMS at the inlet to the SO<sub>2</sub> control device shall be 125 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted, and the span value of the SO<sub>2</sub> CEMS at the outlet from the SO<sub>2</sub> control device shall be 50 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of Rule 260.42c, the span value of the SO<sub>2</sub> CEMS at the outlet from the SO<sub>2</sub> control device (or outlet of the steam generating unit if no SO<sub>2</sub> control device is used) shall be 125 percent of the maximum estimated hourly potential SO<sub>2</sub> emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO<sub>2</sub> control device (or outlet of the steam generating unit if no SO<sub>2</sub> control device is used) as required under Section (a) of this rule, an owner or operator may elect to determine the average SO<sub>2</sub> emission rate by sampling the

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

(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 provides procedures for converting these measurements into the format to be used in calculating the average SO<sub>2</sub> 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<sub>2</sub> at the inlet or outlet of the SO<sub>2</sub> 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<sub>2</sub> and carbon dioxide measurement train operated at the candidate location and a second similar train operated according to the procedures in Section 3.2 and the applicable procedures in Section 7 of Performance Specification 2 (Appendix B). Method 6B, Method 6A, or a combination of Methods 6 and 3 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 Sections (a) and (d) of this rule shall not apply to affected facilities subject to Rule 260.42c(h)(1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO<sub>2</sub> standards based on fuel supplier certification, as described under Rule 260.48c(f)(1), (2), or (3), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to Section (a) of this rule, or conducting as-fired fuel sampling pursuant to Subsection (d)(1) of this rule, 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 Control Officer.

**RULE 260.47c. 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 Rule 260.43c shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

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

**RULE 260.48c REPORTING AND RECORDKEEPING REQUIREMENTS**

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by Rule 260.7 of this Regulation. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under Rule 260.42c, or Rule 260.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO<sub>2</sub> emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of Rule 260.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits of Rule 260.42c, or the particulate matter or opacity limits of Rule 260.43c, shall submit to the Control Officer the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS 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 Rule 260.43c(c) shall submit excess emission reports for any calendar quarter for which there are excess emissions from the affected facility. If there are no excess emissions during the calendar quarter, the owner or operator shall submit a report semiannually stating that no excess emissions occurred during the semiannual reporting period. The initial quarterly report shall be postmarked by the 30th day of the third month following the completion of the initial performance test, unless no excess emissions occur during that quarter. The initial semiannual report shall be postmarked by the 30th day of the sixth month following the completion of the initial performance test, or following the date of the previous quarterly report,

as applicable. Each subsequent quarterly or semiannual report shall be postmarked by the 30th day following the end of the reporting period.

(d) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits, fuel oil sulfur limits, or percent reduction requirements under Rule 260.42c shall submit quarterly reports to the Control Officer. The initial quarterly report shall be postmarked by the 30th day of the third month following the completion of the initial performance test. Each subsequently quarterly report shall be postmarked by the 30th day following the end of the reporting period.

(e) The owner or operator of each affected facility subject to the SO<sub>2</sub> emission limits, fuel oil sulfur limits, or percent reduction requirements under Rule 260.43c shall keep records and submit quarterly reports as required under Section (d) of this rule, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

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

(3) Each 30-day average percent of potential SO<sub>2</sub> emission rate calculated during the reporting period, ending with the last 30-day period in the quarter; 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<sub>2</sub> 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 Subsections (f)(1), (2), or (3) of this rule, as applicable. In addition to records of fuel supplier certifications, the quarterly 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 quarter.

(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 Rule 260.41c.

(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 Rule 260.42c or Rule 260.43c 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 rule shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

**IT IS FURTHER RESOLVED AND ORDERED** that the addition of Subpart Dc to Regulation X shall take effect and be in force on the date of delegation of enforcement authority to the Air Pollution Control District by the U.S. Environmental Protection Agency.

**PASSED AND ADOPTED** by the Air Pollution Control Board of the San Diego County Air Pollution Control District, State of California, this 15th day of July, 1992 by the following votes:

AYES: Members Bilbray, Bailey, Golding, Williams, and  
MacDonald  
NOES: Members None  
ABSENT: Members None \_ \_ \_

STATE OF CALIFORNIA)ss  
County of San Diego)

I, THOMAS J. PASTUSZKA, Clerk of the Air Pollution Control Board, County of San Diego, State of California, hereby certify that I have compared the foregoing copy with the original resolution passed and adopted by said Board at a regular meeting thereof, at the time and by the vote therein stated, which original resolution is now on file in my office; that the same contains a full, true and correct transcript therefrom and of the whole thereof.

Witness my hand and the seal of the Air Pollution Control Board, County of San Diego, State of California, this 21st day of July, 1992.

(SEAL)

THOMAS J. PASTUSZKA  
Clerk of the Air Pollution Control Board  
San Diego County Air Pollution Control  
District

By

*Maria A. Tiscareño*  
\_\_\_\_\_  
María A. Tiscareño, Deputy

*Approved as to form and legality.*  
By *L. Dutton*  
Deputy