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Analysis of State and Federal Sulfur Dioxide Emission Regulations for Combustion Sources

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ANALYSIS OF STATE AND FEDERAL SULFUR DIOXIDE EMISSION REGULATIONS FOR COMBUSTION SOURCES

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Section 1

INTRODUCTION

State Implementation Plan (SIP) regulations and Federal new source performance standards (NSPS) pertaining to sulfur dioxide (SO_2) emissions from fuel combustion have been compiled and summarized in this report. The report is intended to be a general reference for industry, environmental groups, and the general public. State regulations which were submitted to the Environmental Protection Agency (EPA) and have been approved as part of the SIP as of December 31, 1980 are included. Appendix C also lists Federal Register notices of subsequent SIP revisions that affect SO_2 emission requirements. Regulations applicable specifically to incineration of solid waste or to processes which include fuel combustion (cement kiln, lime calciner, etc.) were not included in this compilation. The source categories to which the regulations presented herein apply are broadly defined as indirect and direct heat exchangers, and primarily steam generators (boilers).

This report will also serve as a quick reference for estimating SO_2 emission rates, assessing ranges of SO_2 control, and quantifying the relative stringency of emission limits. It was developed to serve as a starting point for broad control strategy evaluations and is not intended to be a precise reference for individual compliance determinations. Users are cautioned to contact the appropriate State and/or local air pollution control agency and EPA Regional Office to verify the specific SO_2 emission limit that is applicable to an individual source.

Sulfur dioxide regulations vary greatly among the States and even within an individual State. They have become more specific to boiler size, fuel type, and geographic location in recent years. This report attempts to present this variety of emission limits in the simplest tabular format possible. Also, we have attempted to present all the important factors which influence the determination of compliance with an emission limit. Compliance factors, such as actual or rated heat input, test method, and length of time over which emissions are averaged greatly influence the stringency of the limit.

Section 2

SUMMARY

When establishing sulfur dioxide (SO_2) emission limits for fuel combustion installations, each State's goal was attainment and maintenance of the national ambient air quality standards (NAAQS) for SO_2. The form, stringency, and applicability of regulations often depend upon many parameters such as boiler age, fuel type, facility size and method of determination (actual or design heat input), and geographical location. These parameters are delineated by State in Table 1. In New York State, for example, it is necessary to determine the location (city or county) of the source, whether it is existing or new (construction after 3/15/73), the size of the boiler as determined by its actual heat input rate (Btu/hr), and the type of fuel burned (distillate oil, residual oil or solid fuel). The regulation is a limit on the sulfur emission rate (pounds sulfur/million Btu heat input) or the sulfur content of the fuel. In the State of Washington, on the other hand, all fuel combustion sources can emit no more than 1000 ppm SO_2 by volume. The location, size or age of the facility, and type of fuel are not factors in determining the emission limit.

For comparison purposes, the most representative SIP emission limits for each State are presented in common units of pounds sulfur dioxide per million Btu heat input (lb SO_2/ mm Btu) in Table 2 for residual oil and Table 3 for solid fossil fuels. The most representative emission limits were taken as those that would be applicable over the greatest portion of the State. (Section 5 of this report presents a more detailed breakdown of SO_2 limits applicable in different areas of each State.) In some cases, an emission limit greater than that allowed under the Federal new source performance standards (NSPS) is listed. This higher limit is shown because it could apply to a wider variety of sources than those defined in 40 CFR 60.40 and 60.40a. However, it should be understood that the NSPS would supersede less stringent SIP limits when a source falls under both regulations.

Overall review of the information contained in Tables 2 and 3 reveals the following. First, within a specific State there is generally little variation in allowable emissions due to facility size (mm Btu/hr). This means that the majority of the States require the same degree of SO_2 control for existing sources regardless of boiler size. Exceptions to this rule are States such as Kentucky and Nevada, who specify limits by equations. Second, emission limits for residual oil are more stringent than those for coal in a number of States such as New Hampshire, Maine, New York, Maryland, Pennsylvania, Georgia, Kentucky, Illinois, Michigan, Minnesota, Ohio, Oklahoma, Texas, Iowa, Colorado, Utah, and Hawaii. Other States do not differentiate between fuel types. Finally, most existing source SO_2 regulations are designed to be met by burning naturally low sulfur fuel rather than requiring flue gas scrubbing systems.

Figures 1 and 2 are histograms describing the numbers of States requiring specific levels of SO_2 control. Figure 1 presents the limits which would apply to a boiler burning 250 mm Btu/hr of residual oil. Such a boiler burning oil with 3 percent sulfur would, for example, emit about 3.2 lbs SO_2/mm Btu and meet the applicable emission limit in only 9 States. Thus, oil with less than 3 percent sulfur is required to meet most State standards.

Figure 2 presents the limits which would apply to a boiler burning 250 mm Btu/hr of coal. Since half of the States (25) have limits of less than 3 lbs SO_2/mm Btu, an average sulfur content of less than 2 percent would be required to meet the emission limit.

Approximate ranges of controlled and uncontrolled SO_2 emissions are presented in Figure 3. This chart shows that bituminous coal with 3.0 percent average sulfur and a heating value of 11,500 Btu/hr would emit about 5 lbs SO_2/mm Btu and could meet (on a monthly or annual average) the SO_2 emission limit in about 5 States (Missouri, Illinois, Kentucky, Iowa, and Indiana). This same coal could be physically cleaned to reduce the emission rate (lbs SO_2/mm Btu) 24 to 50 percent.[1] On a long-term basis, it could then meet the standards of up to 19 States. Various flue gas desulfurization (FGD) systems could be used to reduce SO_2 emissions 90 percent and allow that facility to meet the standards of most States.

Table 1. SIP SO_2 EMISSION LIMITATIONS IN THE UNITED STATES (BY EPA REGIONS)[a]
(Applicable to fuel combustion sources)

EPA Region	State	Attain NAAQS for SO_2	Fuel Type	Emission Rate	Emission Concentration	Heat Input		Facility Size	Date Construction Commenced		Classification		
						Actual	Design		New Source	Existing Source	County	City	Area
1	Connecticut	X	X	X			X						
	Maine	X	X										X
	Massachusetts	X	X	X			X					X	X
	New Hampshire	X	X	X					X	X			X
	Rhode Island	X	X	X			X						
	Vermont	X	X	X			X						
2	New Jersey	X	X	X			X	X	X	X	X	X	
	New York	X	X	X		X		X	X	X	X	X	
3	Delaware	X	X	X		X	X	X	X	X	X		
	Maryland	X	X	X		X	X	X			X		X
	Pennsylvania	X	X	X			X	X			X		X
	Virginia	X		X		X					X	X	X
	West Virginia	X				X	X	X			X		X
4	Alabama	X		X			X	X			X		X

[a] Excluding New Source Performance Standards criteria.

Table 1. CONTINUED

EPA Region	State	Attain NAAQS for SO_2	Fuel Type	Emission Rate	Emission Concentration	Heat Input		Facility Size	Date Construction Commenced		Classification		
						Actual	Design		New Source	Existing Source	County	City	Area
4 (cont)	Florida	X	X	X		X		X	X	X	X		
	Georgia	X	X	X		X		X					
	Kentucky	X	X	X		X		X	X	X	X		
	Mississippi	X		X				X	X	X			
	North Carolina	X		X			X	X	X	X			
	South Carolina	X		X			X	X	X	X	X		
	Tennessee	X	X	X			X	X	X	X	X		
5	Illinois	X	X	X			X	X	X	X		X	X
	Indiana	X		X			X	X					X
	Michigan	X	X	X			X	X					
	Minnesota	X	X	X			X	X					X
	Ohio	X		X			X	X			X		
	Wisconsin	X	X	X			X	X	X	X			X
6	Arkansas	X	X	X			X	X		X			

[a] Excluding New Source Performance Standards criteria.

Table 1. CONTINUED

EPA Region	State	Attain NAAQS for SO_2	Fuel Type	Emission Rate	Emission Concentration	Heat Input		Facility Size	Date Construction Commenced		Classification		
						Actual	Design		New Source	Existing Source	County	City	Area
6 (cont)	Louisiana	X			X	X							
	New Mexico	X		X			X	X	X	X			
	Oklahoma	X		X			X	X	X	X			
	Texas	X	X	X	X	X			X	X	X		
7	Iowa	X	X	X			X	X	X	X	X		
	Kansas	X		X			X	X	X	X			
	Missouri	X		X		X	X	X				X	X
	Nebraska	X		X			X			X			
8	Colorado	X	X	X			X	X	X	X			
	Montana	X	X	X		X							
	North Dakota	X		X			X						
	South Dakota	X		X			X						
	Utah	X	X	X		X							
	Wyoming	X	X	X			X	X	X	X			

[a] Excluding New Source Performance Standards criteria.

Table 1. CONCLUDED

EPA Region	State	Attain NAAQS for SO_2	Fuel Type	Emission Rate	Emission Concentration	Heat Input		Facility Size	Date Construction Commenced		Classification		
						Actual	Design		New Source	Existing Source	County	City	Area
9	Arizona	X	X	X		X	X		X	X			
	California[b]	X	X	X		X					X		X
	Hawaii	X	X				X						
	Nevada	X		X		X		X	X	X			
10	Alaska	X			X	X	X						
	Idaho	X	X			X	X	X	X	X			
	Oregon	X	X	X									
	Washington	X			X								

[a] **Excluding New Source Performance Standards criteria.**

[b] Each Air Pollution Control District has individual criteria for fuel burning regulations. For summary purposes, "typical" criteria is specified.

Table 2. REPRESENTATIVE STATE SULFUR DIOXIDE EMISSIONS LIMITATIONS FOR FACILITIES BURNING #5 OR #6 FUEL OIL (lbs. SO_2/MMBtu)

EPA Region	State	Facility Size (MMBtu/hr. heat input) 10	100	250	1,000	10,000
1	Connecticut: existing	0.55	0.55	0.55	0.55	0.55
	new	0.55	0.55	0.55	0.55	0.55
	Maine[a,j]: existing	2.7	2.7	2.7	2.7	2.7
	new	2.7	2.7	2.7	2.7	2.7
	Massachusetts[b,c,j]: existing	1.1	1.1	1.1	1.1	1.1
	new	1.1	1.1	1.1	1.1	1.1
	New Hampshire[a,j]: existing	2.1	2.1	2.1	2.1	2.1
	new	2.1	2.1	2.1	2.1	2.1
	Rhode Island[j]: existing	1.1	1.1	1.1	1.1	1.1
	new	1.1	1.1	1.1	1.1	1.1
	Vermont: existing	3.48[a]	3.48[a]	3.48[a]	0.8	0.8
	new	3.48[a]	3.48[a]	3.48[a]	0.8	0.8
2	New Jersey[b,j]: existing	1.05	1.05	1.05	1.05	1.05
	new	1.05	1.05	1.05	1.05	1.05
	New York[a]: existing	2.1	2.1	2.1	2.1	2.1
	new	2.1	2.1	2.1	0.77	0.77
3	Delaware[a,b,j]: existing	1.8	1.8	1.8	1.8	1.8
	new	1.8	1.8	1.8	1.8	1.8
	Maryland[a,b,j]: existing	N.A.[d]	2.1	2.1	2.1	2.1
	new	N.A.[d]	2.1	2.1	2.1	2.1
	Pennsylvania[j]: existing	4.0	4.0	4.0	4.0	4.0
	new	4.0	4.0	4.0	4.0	4.0
	Virginia[j]: existing	2.64	2.64	2.64	2.64	2.64
	new	2.64	2.64	2.64	2.64	2.64
	Washington, D.C.[a,j]: existing	1.05	1.05	1.05	1.05	1.05
	new	1.05	1.05	1.05	1.05	1.05
	West Virginia[j]: existing	1.6	1.6	1.6	1.6	1.6
	new	1.6	1.6	1.6	1.6	1.6

(continued)

Table 2. Continued

EPA Region	State	Facility Size (MMBtu/hr. heat input) 10	100	250	1,000	10,000
4	Alabama[j]: existing	4.0	4.0	4.0	4.0	4.0
	new	4.0	4.0	4.0	4.0	4.0
	Florida[e]: existing	N.A.[d]	N.A.[d]	N.A.[d]	2.75	2.75
	new	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	Georgia[f,j]: existing	2.6	3.1	3.1	3.1	3.1
	new	2.6	3.1	3.1	3.1	3.1
	Kentucky[b]: existing	6.0	4.49	4.0	4.0	4.0
	new	N.A.[d]	1.17	0.8	N.A.[h]	N.A.[h]
	Mississippi[j]: existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	new	4.8	4.8	4.8	4.8	4.8
	North Carolina[j]: existing	2.3	2.3	2.3	2.3	2.3
	new	2.3	2.3	2.3	2.3	2.3
	South Carolina[j]: existing	3.5	3.5	3.5	3.5	3.5
	new	3.5	3.5	3.5	3.5	3.5
	Tennessee[e,j]: existing	5.0	5.0	5.0	5.0	5.0
	new	5.0	5.0	5.0	5.0	5.0
5	Illinois[j]: existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	new	1.0	1.0	1.0	1.0	1.0
	Indiana[j]: existing	6.0	6.0	6.0	6.0	6.0
	new	6.0	6.0	6.0	6.0	6.0
	Michigan[j]: existing	1.7	1.7	1.7	1.1	1.1
	new	1.7	1.7	1.7	1.1	1.1
	Minnesota[e,j]: existing	2.0	2.0	2.0	2.0	2.0
	new	2.0	2.0	2.0	2.0	2.0
	Ohio[e,j]: existing	N.A.[d]	1.6	1.6	1.6	1.6
	new	1.6	1.6	1.6	1.6	1.6
	Wisconsin[e]: existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	new	N.A.[d]	N.A.[d]	N.A.[d]	0.8	0.8

(continued)

Table 2. Continued

EPA Region	State	Facility Size (MMBtu/hr. heat input) 10	100	250	1,000	10,000
6	Arkansas[h]: existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	new	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	Louisiana[i,j]: existing	4.6	4.6	4.6	4.6	4.6
	new	4.6	4.6	4.6	4.6	4.6
	New Mexico: existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	new	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	Oklahoma: existing	0.8	0.8	0.8	0.8	0.8
	new	0.8	0.8	0.8	0.8	0.8
	Texas[e,i,j]: existing	0.94	0.94	0.94	0.94	0.94
	new	0.94	0.94	0.94	0.94	0.94
7	Iowa[j]: existing	2.5	2.5	2.5	2.5	2.5
	new	2.5	2.5	2.5	2.5	2.5
	Kansas[j]: existing	3.0[c]	3.0[c]	3.0[c]	3.0[c]	3.0[c]
	new	3.0[c]	3.0[c]	3.0[c]	3.0[c]	3.0[c]
	Missouri[j]: existing	12.9	12.9	12.9	12.9	12.9
	new	12.9	12.9	12.9	12.9	12.9
	Nebraska[j]: existing	2.5	2.5	2.5	2.5	2.5
	new	2.5	2.5	2.5	2.5	2.5
8	Colorado: existing	1.5	1.5	1.5	0.8	0.8
	new	0.8	0.8	0.3	0.3	0.3
	Montana[c,j]: existing	2.0	2.0	2.0	2.0	2.0
	new	2.0	2.0	2.0	2.0	2.0
	North Dakota[j]: existing	3.0	3.0	3.0	3.0	3.0
	new	3.0	3.0	3.0	3.0	3.0
	South Dakota[j]: existing	3.0	3.0	3.0	3.0	3.0
	new	3.0	3.0	3.0	3.0	3.0
	Utah[c,j]: existing	1.7	1.7	1.7	1.7	1.7
	new	1.7	1.7	1.7	1.7	1.7
	Wyoming: existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	new	N.A.[d]	N.A.[d]	N.A.[d]	0.8	0.8

(continued)

Table 2. Continued

EPA Region	State	Facility Size (MMBtu/hr. heat input) 10	100	250	1,000	10,000
9	Arizona: existing	2.2	2.2	2.2	2.2	2.2
	new	0.8	0.8	0.3	0.3	0.3
	California[a,b]: existing	0.53	0.53	0.53	0.53	0.53
	new	0.53	0.53	0.53	0.53	0.53
	Hawaii[a,j]: existing	2.1	2.1	2.1	2.1	2.1
	new	2.1	2.1	2.1	2.1	2.1
	Nevada[c,j]: existing	1.4	1.4	0.8	0.8	0.8
	new	1.4	1.4	0.8	0.8	0.8
10	Alaska[i,j]: existing	1.14	1.14	1.14	1.14	1.14
	new	1.14	1.14	1.14	1.14	1.14
	Idaho[a,j]: existing	1.85	1.85	1.85	1.85	1.85
	new	1.85	1.85	1.85	1.85	1.85
	Oregon[a,j]: existing	1.85	1.85	1.85	1.85	1.85
	new	1.85	1.85	1.85	1.85	1.85
	Washington[i,j]: existing	2.29	2.29	2.29	2.29	2.29
	new	2.29	2.29	2.29	2.29	2.29

[a] Emissions limitation was expressed in percent sulfur content of the fuel. Conversion to lbs. SO_2/MMBtu was based on the assumptions of 100 percent conversion of sulfur to sulfur dioxide, and a heating value of 19,000 Btu/lb (residual oil). The following equation calculates the equivalent emission rate:

$$\text{Emission Rate (lbs. } SO_2\text{/MMBtu)} = \left(\frac{1{,}000{,}000 \text{ Btu}}{\text{Heating Value (Btu/lb)}}\right) \times \%S \text{ (2 lbs. } SO_2\text{/lb. S)}$$

[b] Emissions limitations were not expressed for the entire state. The median value was selected for comparison.

[c] Emissions limitation was expressed in lbs. S/MMBtu. The following equation calculates the equivalent emission rate:

$$\text{Emission Rate (lbs. } SO_2\text{/MMBtu)} = 2 \times \text{(lbs. S/MMBtu)}$$

[d] Refers to "Not Applicable" for comparison purposes. Either emissions were not regulated in that state or other reason specified.

[e] Emissions limitations were for individual sources and counties. The value shown represents only limitations which apply to the entire state.

[f] The state regulation limits both fuel sulfur content and the SO_2 emission rate depending on stack height. However, only the limits on fuel sulfur content are included in the SIP.

[g] Emissions limitations are based on effective stack height for entire plant (equation).

[h] Emissions limitations are based on federal regulations. See Appendix A and Appendix B.

[i] Emissions limitation was expressed in parts per million (ppm). Conversion to lbs. SO_2/MMBtu was based on the assumptions that F factors (dry basis) were 9,820 dscf/MMBtu (coal) and 9,220 dscf/MMBtu (oil), and a 6 percent oxygen content in the flue gas. The following equations calculate the equivalent emission rate at standard temperature (20°C or 68°F) and pressure (760 mm Hg or 29.92 in. Hg):

$$C = 1.660 \times 10^{-7} \text{ (X ppm)}$$

$$E = C\, F_d \left[\frac{20.9}{20.9\text{-percent } O_2} \right]$$

where: E = pollutant emissions (lbs. SO_2/MMBtu)
C = pollutant concentration (lbs. SO_2/dscf)
F_d = dry basis F factor, which is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted.

[j] New source performance standards (40 CFR 60.40 and 60.40a) supersede less stringent State emission limits when applicable to a new combustion source.

Table 3. REPRESENTATIVE STATE SULFUR DIOXIDE EMISSIONS LIMITATIONS FOR FACILITIES BURNING SOLID FOSSIL FUEL (lbs. SO_2/MMBtu)

EPA Region	State	Facility Size (MMBtu/hr. heat input)				
		10	100	250	1,000	10,000
1	Connecticut: existing	0.55	0.55	0.55	0.55	0.55
	new	0.55	0.55	0.55	0.55	0.55
	Maine[a,j]: existing	4.13	4.13	4.13	4.13	4.13
	new	4.13	4.13	4.13	4.13	4.13
	Massachusetts[b,c]: existing	1.1	1.1	1.1	1.1	1.1
	new	1.1	1.1	1.1	1.1	1.1
	New Hampshire[j]: existing[a]	5.3	5.3	5.3	5.3	5.3
	new[c]	3.0	3.0	3.0	3.0	3.0
	Rhode Island: existing	1.1	1.1	1.1	1.1	1.1
	new	1.1	1.1	1.1	1.1	1.1
	Vermont: existing	3.3	3.3	3.3	1.2	1.2
	new	3.3	3.3	3.3	1.2	1.2
2	New Jersey[b]: existing	0.3	0.3	0.3	0.3	0.3
	new	0.3	0.3	0.3	0.3	0.3
	New York[a]: existing	N.A.[d]	4.13	4.13	4.13	4.13
	new	N.A.[d]	4.13	4.13	1.04	1.04
3	Delaware[a,b,j]: existing	1.65	1.65	1.65	1.65	1.65
	new	1.65	1.65	1.65	1.65	1.65
	Maryland[b,j]: existing	N.A.[d]	3.5	3.5	3.5	3.5
	new	N.A.[d]	3.5	3.5	3.5	3.5
	Pennsylvania[j]: existing	4.8	4.8	4.8	4.8	4.8
	new	4.8	4.8	4.8	4.8	4.8
	Virginia[j]: existing	2.64	2.64	2.64	2.64	2.64
	new	2.64	2.64	2.64	2.64	2.64
	Washington, D.C.[a,j]: existing	1.65	1.65	1.65	1.65	1.65
	new	1.65	1.65	1.65	1.65	1.65
	West Virginia[j]: existing	1.6	1.6	1.6	1.6	1.6
	new	1.6	1.6	1.6	1.6	1.6

(continued)

Table 3. Continued

EPA Region	State	Facility Size (MMBtu/hr. heat input)				
		10	100	250	1,000	10,000
4	Alabama[j]: existing	4.0	4.0	4.0	4.0	4.0
	new	4.0	4.0	4.0	4.0	4.0
	Florida[e]: existing	N.A.[d]	N.A.[d]	N.A.[d]	6.17	6.17
	new	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	Georgia[f,j] existing	4.35	5.22	5.22	5.22	5.22
	new	4.35	5.22	5.22	5.22	5.22
	Kentucky: existing	9.0	6.73	6.0	6.0	6.0
	new	5.0	1.8	1.20	0.65	0.23
	Mississippi[j]: existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	new	4.8	4.8	4.8	4.8	4.8
	North Carolina[j]: existing	2.3	2.3	2.3	2.3	2.3
	new	2.3	2.3	2.3	2.3	2.3
	South Carolina[j]: existing	3.5	3.5	3.5	3.5	3.5
	new	3.5	3.5	3.5	3.5	3.5
	Tennessee[e,j]: existing	5.0	5.0	5.0	5.0	5.0
	new	5.0	5.0	5.0	5.0	5.0
5	Illinois: existing	6.8	6.8	6.8	N.A.[g]	N.A.[g]
	new	1.8	1.8	1.8	1.2	1.2
	Indiana[j]: existing	6.0	6.0	6.0	6.0	6.0
	new	6.0	6.0	6.0	6.0	6.0
	Michigan[j]: existing	2.4	2.4	2.4	1.6	1.6
	new	2.4	2.4	2.4	1.6	1.6
	Minnesota[e,j]: existing	4.0	4.0	4.0	4.0	4.0
	new	4.0	4.0	4.0	4.0	4.0
	Ohio[b,j]: existing	3.6	3.6	3.6	3.6	3.6
	new	3.6	3.6	3.6	3.6	3.6
	Wisconsin[g]: existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	new	N.A.[d]	N.A.[d]	N.A.[d]	1.2	1.2

(continued)

Table 3. Continued

EPA Region	State		Facility Size (MMBtu/hr. heat input) 10	100	250	1,000	10,000
6	Arkansas[h]:	existing	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
		new	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]	N.A.[d]
	Louisiana[i,j]:	existing	4.6	4.6	4.6	4.6	4.6
		new	4.6	4.6	4.6	4.6	4.6
	New Mexico:	existing	N.A.[d]	N.A.[d]	N.A.[d]	1.2	1.2
		new	N.A.[d]	N.A.[d]	N.A.[d]	1.2	1.2
	Oklahoma:	existing	1.2	1.2	1.2	1.2	1.2
		new	1.2	1.2	1.2	1.2	1.2
	Texas[e,j]:	existing	3.0	3.0	3.0	3.0	3.0
		new	3.0	3.0	3.0	3.0	3.0
7	Iowa:	existing	6.0	6.0	6.0	6.0	6.0
		new	6.0	6.0	6.0	N.A.[d]	N.A.[d]
	Kansas[j]:	existing	3.0[c]	3.0[c]	3.0[c]	3.0[c]	3.0[c]
		new	3.0[c]	3.0[c]	3.0[c]	3.0[c]	3.0[c]
	Missouri[j]:	existing	12.9	12.9	12.9	12.9	12.9
		new	12.9	12.9	12.9	12.9	12.9
	Nebraska[j]:	existing	2.5	2.5	2.5	2.5	2.5
		new	2.5	2.5	2.5	2.5	2.5
8	Colorado:	existing	1.8	1.8	1.8	1.2	1.2
		new	1.2	1.2	1.2	0.4	0.4
	Montana[c,j]:	existing	2.0	2.0	2.0	2.0	2.0
		new	2.0	2.0	2.0	2.0	2.0
	North Dakota[j]:	existing	3.0	3.0	3.0	3.0	3.0
		new	3.0	3.0	3.0	3.0	3.0
	South Dakota[j]:	existing	3.0	3.0	3.0	3.0	3.0
		new	3.0	3.0	3.0	3.0	3.0
	Utah[c,j]:	existing	2.0	2.0	2.0	2.0	2.0
		new	2.0	2.0	2.0	2.0	2.0
	Wyoming:	existing	N.A.[d]	N.A.[d]	N.A.[d]	1.2	0.3
		new	N.A.[d]	N.A.[d]	N.A.[d]	0.2	0.2

(continued)

Table 3. Continued

EPA Region	State	Facility Size (MMBtu/hr. heat input) 10	100	250	1,000	10,000
9	Arizona: existing	1.0	1.0	1.0	1.0	1.0
	new	0.8	0.8	0.8	0.8	0.8
	California[a,b]: existing	0.83	0.83	0.83	0.83	0.83
	new	0.83	0.83	0.83	0.83	0.83
	Hawaii[a,j]: existing	3.3	3.3	3.3	3.3	3.3
	new	3.3	3.3	3.3	3.3	3.3
	Nevada[c]: existing	1.4	1.4	1.2	1.2	1.2
	new	1.4	1.4	1.2	1.2	1.2
10	Alaska[i]: existing	1.14	1.14	1.14	1.14	1.14
	new	1.14	1.14	1.14	1.14	1.14
	Idaho[a,j]: existing	1.65	1.65	1.65	1.65	1.65
	new	1.65	1.65	1.65	1.65	1.65
	Oregon[a,j]: existing	1.65	1.65	1.65	1.65	1.65
	new	1.65	1.65	1.65	1.65	1.65
	Washington[i,j]: existing	2.29	2.29	2.29	2.29	2.29
	new	2.29	2.29	2.29	2.29	2.29

[a] Emissions limitation was expressed in percent sulfur content of the fuel. Conversion to lbs. SO_2/MMBtu was based on the assumptions of 95 percent conversion of sulfur to sulfur dioxide, and a heating value of 11,500 Btu/lb (coal). The following equation calculates the equivalent emission rate:

$$\text{Emission Rate (lbs. } SO_2\text{/MMBtu)} = .95\left(\frac{1{,}000{,}000 \text{ Btu}}{\text{Heating Value (Btu/lb)}}\right) \times \%S \text{ (2 lbs. } SO_2\text{/lb. S)}$$

[b] Emissions limitations were not expressed for the entire state. The median value was selected for comparison.

[c] Emissions limitation was expressed in lbs. S/MMBtu. The following equation calculates the equivalent emission rate:

$$\text{Emission Rate (lbs. } SO_2\text{/MMBtu)} = 2 \times \text{(lbs. S/MMBtu)}$$

[d] Refers to "Not Applicable" for comparison purposes. Either emissions were not regulated in that state or other reason specified.

Table 3. Concluded

[e] Emissions limitations were for individual sources and counties. The value shown represents only limitations which apply to the entire state.

[f] The state regulation limits both fuel sulfur content and the SO_2 emission rate depending on stack height. However, only the limits on fuel sulfur content are included in the SIP

[g] Emissions limitations are based on effective stack height for entire plant (equation).

[h] Emissions limitations are based on federal regulations. See Appendix A and Appendix B.

[i] Emissions limitation was expressed in parts per million (ppm). Conversion to lbs. SO_2/MMBtu was based on the assumptions that F factors (dry basis) were 9,820 dscf/MMBtu (coal) and 9,220 dscf/MMBtu (oil), and a 6 percent oxygen content in the flue gas. The following equations calculate the equivalent emission rate at standard temperature (20°C or 68°F) and pressure (760 mm Hg or 29.92 in. Hg):

$$C = 1.660 \times 10^{-7} \text{ (X ppm)}$$

$$E = C\,F_d \left[\frac{20.9}{20.9\text{-percent } O_2}\right]$$

where: E = pollutant emissions (lbs. SO_2/MMBtu)
C = pollutant concentration (lbs. SO_2/dscf)
F_d = dry basis F factor, which is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted.

[j] New source performance standards (40 CFR 60.40 and 60.40a) supersede less stringent state emission limits when applicable to a new combustion source.

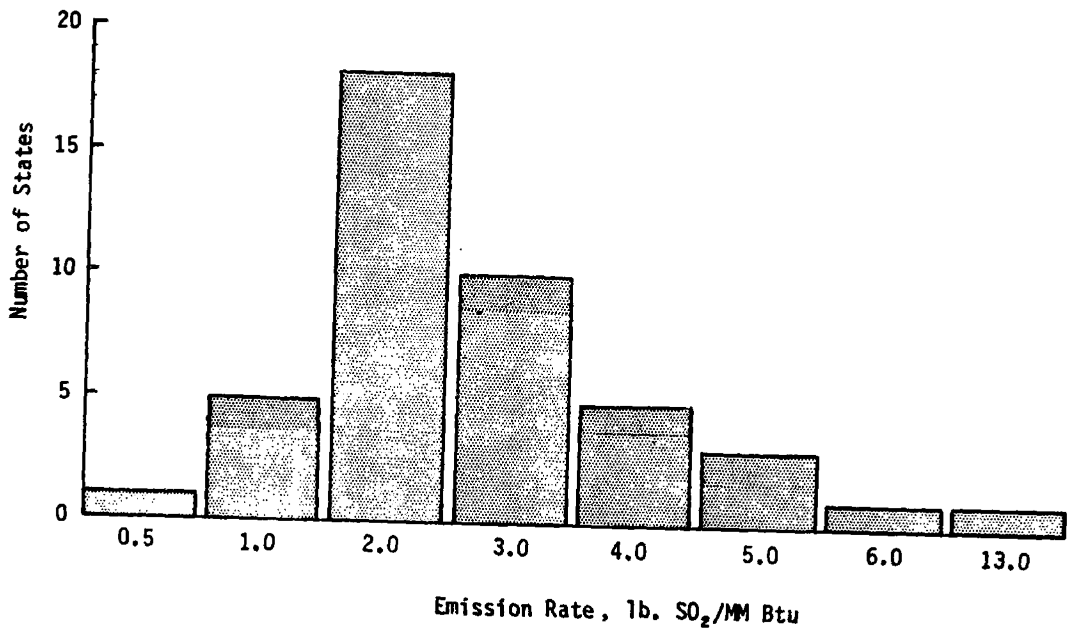

Figure 1. Maximum Allowable SO_2 Emission Rate for an Existing 250 MM Btu/hr. Residual Oil Fired Boiler.

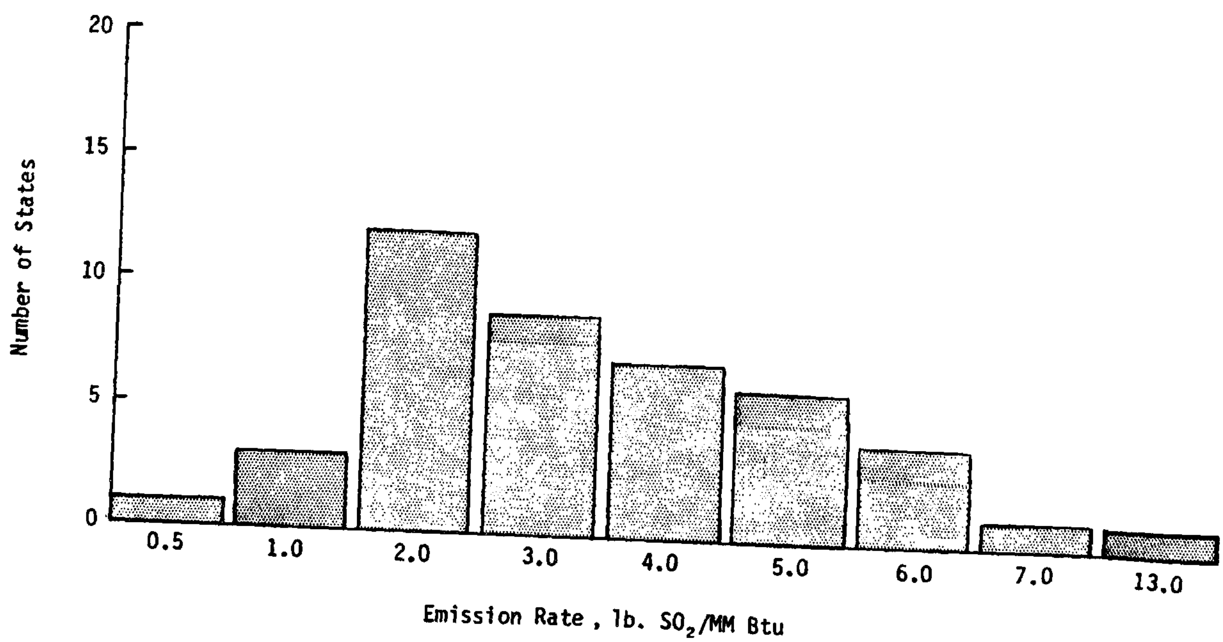

Figure 2. Maximum Allowable SO_2 Emission Rate for an Existing 250 MM Btu/hr. Coal Fired Boiler.

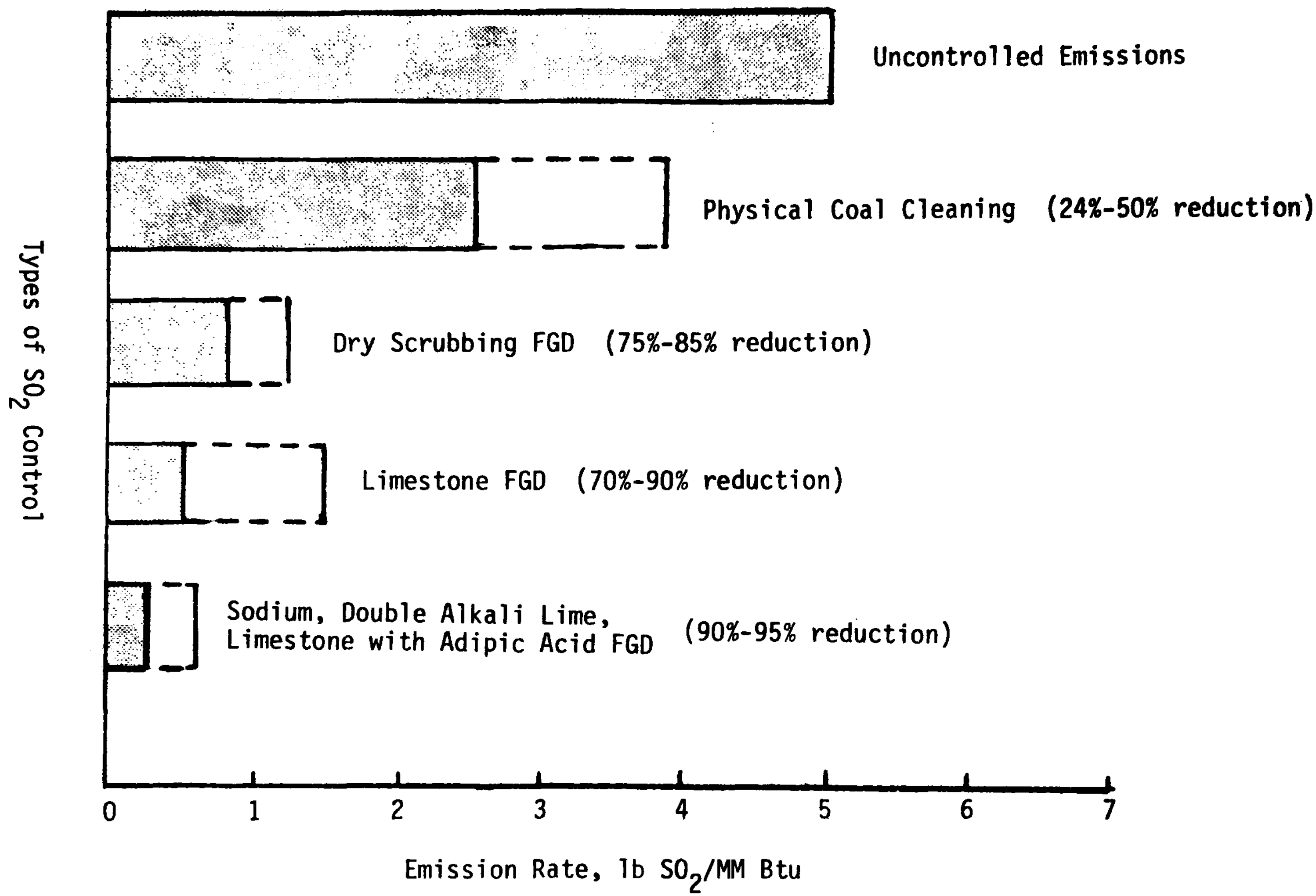

Figure 3. Ranges of SO_2 emission rates for a boiler fueled with bituminous coal: 11,500 Btu/lb., 3.0% S.

Section 3

REGULATION OF SULFUR DIOXIDE EMISSIONS FROM COMBUSTION OF FUELS

The Clean Air Act Amendments of 1970 (CAA) required each State to prepare a plan indicating how the National Ambient Air Quality Standards (NAAQS) for particulates, sulfur dioxide, oxides of nitrogen, and carbon monoxide would be attained and/or maintained. States adopted regulations limiting sulfur dioxide emissions from fuel combustion in response to this requirement. These limits took the form of limits on the percent sulfur (by weight) in fuels burned, pounds sulfur or sulfur dioxide emitted per million (mm) Btu of heat input to the furnace, and limits on the parts per million (ppm) concentration of sulfur dioxide in the flue gas.

Individual State Implementation Plans have been revised several times since 1970. These revisions have resulted in regulations becoming more site-specific (dependent on the location of the source by county or municipality rather than a Statewide regulation). Some States have been able to show that the original limits on fuel sulfur content adopted were more stringent than necessary to attain the NAAQS and are in the process of relaxing those regulations.

The CAA required EPA to develop standards of performance for new stationary sources also. In response to this requirement, EPA has adopted "Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971" and "Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978."

3.1 - POTENTIAL EMISSIONS OF SULFUR DIOXIDE FROM FUEL COMBUSTION

Sulfur dioxide emissions from combustion of fuels are proportional to the amount of sulfur in the fuel. In the case of fuel oil, it is assumed that all the sulfur in the oil is oxidized during the combustion process and emitted as sulfur dioxide. Estimates of SO_2 emission rates from fuel oil combustion can generally be made using the following equations.

Residual oil - lbs SO_2/mm Btu = 1.05 x % S in fuel

Distillate oil - lbs SO_2/mm Btu = 1.0 x % S in fuel

These equations are based on the general assumptions that residual oils have an approximate heating value of 150,000 Btu/gallon and distillate oils have a value of 140,000 Btu/gallon.[2] Thus, combustion of a 2.3 percent sulfur residual oil would have a resultant emission rate of approximately 2.4 lbs SO_2/mm Btu of heat input.

For the combustion of coal, about five percent of the coal's sulfur remains in the bottom ash and thus 95 percent is emitted as sulfur dioxide.[2] To estimate the emission rate in lbs SO_2/mm Btu, one only needs to know the percent sulfur and the heating value in Btu/lb. The following procedure can then be used for estimation:

lbs SO_2/mm Btu = CF x % S in coal

Where CF is -

Btu/lb	CF
10,000	1.9
10,500	1.81
11,000	1.73
11,500	1.65
12,000	1.58
12,500	1.52

Thus, a coal of 3 percent sulfur content and a heating value of 11,500 Btu/lb would have an approximate SO_2 emission rate of 5 lbs/mm Btu.

The normal range of sulfur dioxide emissions (lb SO_2/mm Btu) is presented in Table 4. The range of emission rates was maximized by assuming the lowest sulfur fuel had the highest heating value and the highest sulfur fuel had the lowest heating value. There is no direct correlation of sulfur content and heating value in nature, however.

It can be seen that a low sulfur (.01 percent) distillate oil could yield as little of 0.01 lb SO_2/mm Btu of fuel burned while a high sulfur (6.1 percent) bituminous coal could yield as much as 12 lb SO_2/mm Btu. Although wood and bark have very low sulfur contents, they also have low heating values; therefore, SO_2 emissions fall in the same range as those from #1 or #2 fuel oil.

3.2 - STATE SULFUR DIOXIDE EMISSION REGULATIONS

Several approaches to regulating SO_2 emissions from fuel combustion have been adopted by States in order to attain and maintain the NAAQS. The regulations applicable in each State are delineated in Section 5 along with notes on procedures such as test methods, averaging time, monitoring and reporting requirements used to determine compliance.

Continuous monitoring of SO_2 emissions is generally not required by the SIPs. Some States require routine monitoring of fuel characteristics. Often, however, monitoring and reporting requirements are left to the discretion of the director of the air pollution control program. American Society for Testing Materials (ASTM) methods are usually specified for determining fuel sulfur content and heating value of the fuel. Most States selected EPA Method 6 as the source test method for determining flue gas emission concentrations. About 18 States left specification of test methods to the director of the air pollution control program.

The averaging time, or time period over which average SO_2 emissions must fall below the allowable limit, is seldom specified in the State regulations. Compliance as determined by stack test procedures is basically instantaneous. That is, the average emission rate during the 1-3 hour stack

Table 4

Range of Sulfur Contents, Heating Values and Potential Sulfur Dioxide Emission Rates for Typical Fuels

Fuel	% Sulfur (by weight)	Heating Value (Btu/lb as burned)	SO_2 Emissions lb/mm Btu
Pipeline Natural Gas	Negligible	-	-
Wood - Typical	0.02	4560	0.1
Bark - Typical	0.02	4370	0.1
Distillate Oil[3]			
#1	0.01-0.5	19,670-19,860	0.01-0.5
#2	0.05-1.0	19,170-19,750	0.05-1.0
#4	0.2-2.0	18,280-19,400	0.2-2
Residual Oil[3]			
#5	0.5-3.0	18,100-19,020	0.5-3
#6	0.7-3.5	17,410-18,990	0.7-4
Anthracite Coal[3]	0.6-0.8	11,925-12,925	0.9-1
Bituminous Coal[3]	0.7-6.1	9,700-14,715	0.9-12
Subbituminous Coal[3]	0.3-0.6	8,320-11,340	0.5-1
Lignite Coal[3]	0.4-0.9	6,500-9,700	0.8-3

test must fall below the allowable limit. Averaging time is not, generally, important when oil is burned because the sulfur content of a given supply of oil is nearly constant. Averaging time becomes important, however, when burning coal because the sulfur content, even from a single mine, may vary significantly. Therefore, when a coal is said to have 2 percent sulfur content, that is usually the average of many samples taken over the period of a month or even longer. This coal could probably meet an emission limit of 3 lb SO_2/ mm Btu if compliance is determined by averaging several emission measurements taken over a 30-day period. If emission measurements taken over a 24-hour period are averaged, however, the emission rate could be higher if the sulfur content of the coal burned during the period of testing was above the long-term average.

A review of Section 5 indicates that State SO_2 emission regulations generally limit the amount of SO_2 which can be emitted per million Btu heat input to the furnace (lb SO_2/mm Btu) or the sulfur content of the fuels which can be burned. The following paragraphs give examples of parameters in different States that affect the stringency of emission limits applicable to an individual source.

The New York State SIP, for example, contains very detailed limits on fuel sulfur content. To determine the limit applicable to a particular source, it is necessary to first know its location (county or municipality). The total heat (Btu/hr) actually being burned in all furnaces at the facility is the next important factor. A facility with 10 mm Btu/hr or less is not regulated. In some areas of the State different limits apply to facilities with total heat input greater than 250 mm Btu/hr. Limits are different for existing sources (constructed before 3/15/73) and new sources (constructed after 3/15/73), and for oil and solid fuel. Compliance with the sulfur-in-fuel limits is determined by stack testing (EPA Method 6) and fuel analysis to determine sulfur and ash content, heating value and specific gravity (oil). The gross heat content and ash content of the fuel burned on a weekly basis must be monitored for all facilities with a total heat input greater than 250 mm Btu/hr. Continuous monitoring of stack SO_2 emissions is required for new facilities with heat input greater than 250 mm Btu/hr.

Pennsylvania regulations limit sulfur-in-fuel and SO_2 emission rate (lb/mm Btu) depending on the location, the design fuel burning capacity of each furnace and the type of fuel burned. The equation illustrated in Figure 4 is applicable only to furnaces with heat input capacity greater than or equal to 50 mm Btu/hr but less than 2000 mm Btu/hr and located in the Allegheny County, Beaver Valley, Monongahela Valley air basin. The allowable SO_2 emission rate for furnaces burning solid fossil fuels varies with averaging time. For example, the measured emission rate must always fall below 4.8 lb SO_2/mm Btu in areas I and II (Section 5). Also, the average of all readings for one day (24-hour period) must fall below 4.0 lb/mm Btu (except for two days per month) and the emission average over 30 days must fall below 3.7 lb/mm Btu.

In Virginia and Nevada the emission limits (lbs SO_2/hr) are based on equations (Figures 5 and 9) which are functions of the actual heat input to a single furnace. Compliance is determined in Virginia by stack testing using EPA Method 6 or another State-approved procedure (3 runs) and in Nevada by stack testing using a method specified by the State in the operating permit (2 runs).

Georgia limits the sulfur content of the fuel burned to $\leq$2.5 percent for furnaces actually burning less than 100 mm Btu/hr and $\leq$3.0 percent for furnaces burning 100 mm Btu/hr or greater of fuel. It also limits the SO_2 emission rate (lb SO_2/mm Btu) based on equations (Figures 6, 7, and 8) which are functions of the furnace exhaust stack height. The limits based on stack height are not part of the Georgia SIP, however.[a]

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[a]The EPA Region IV office "determined that the sulfur-in-fuel limit. . . is sufficient standing alone to assure attainment and maintenance of the national air quality standards for SO_2" (41 FR 35185, August 20, 1976). Also, application of the stack height rules must be in accordance with "Legal Interpretation and Guideline to Implementation of Recent Court Decisions on the Subject of Stack Height Increase as a Means of Meeting Federal Ambient Air Quality Standards" (41 FR 7450, February 18, 1976).

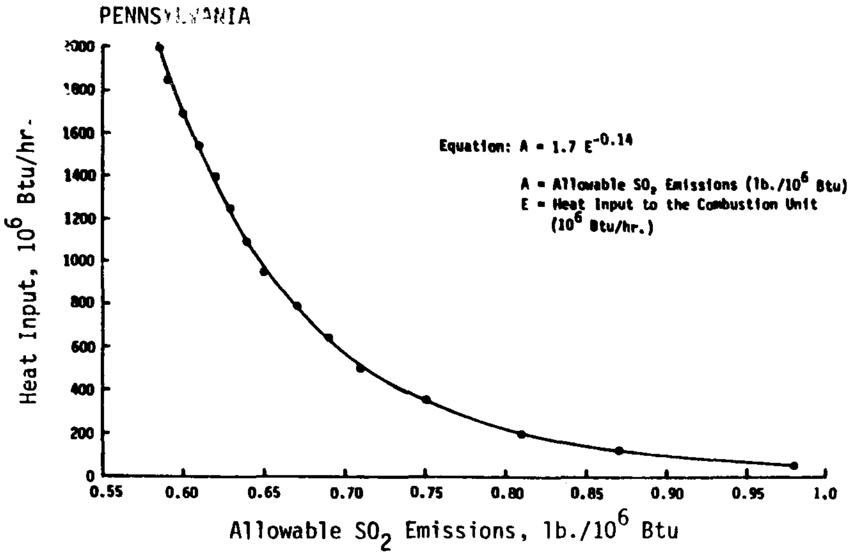

Figure 4. Determination of SO_2 Emission Rate by Heat Input

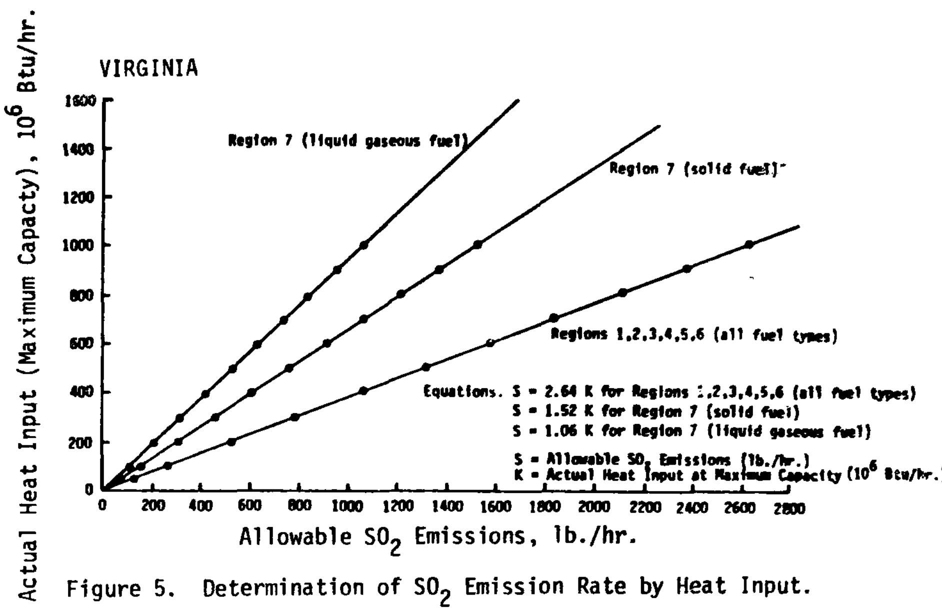

Figure 5. Determination of SO_2 Emission Rate by Heat Input.

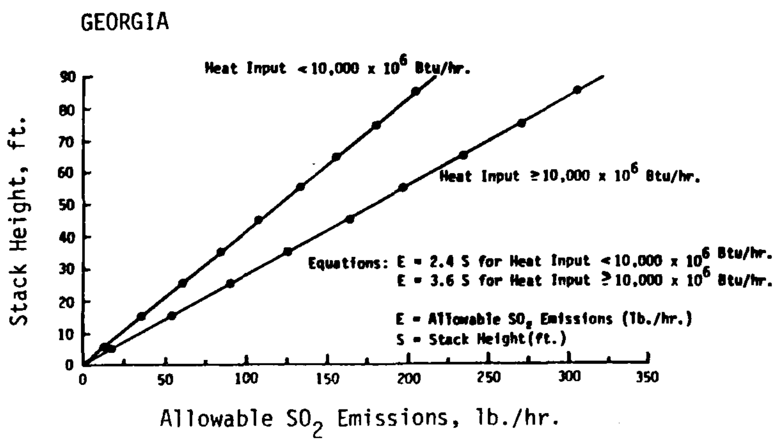

Figure 6. Determination of SO_2 Emission Rate for Stack Heights <90 ft.

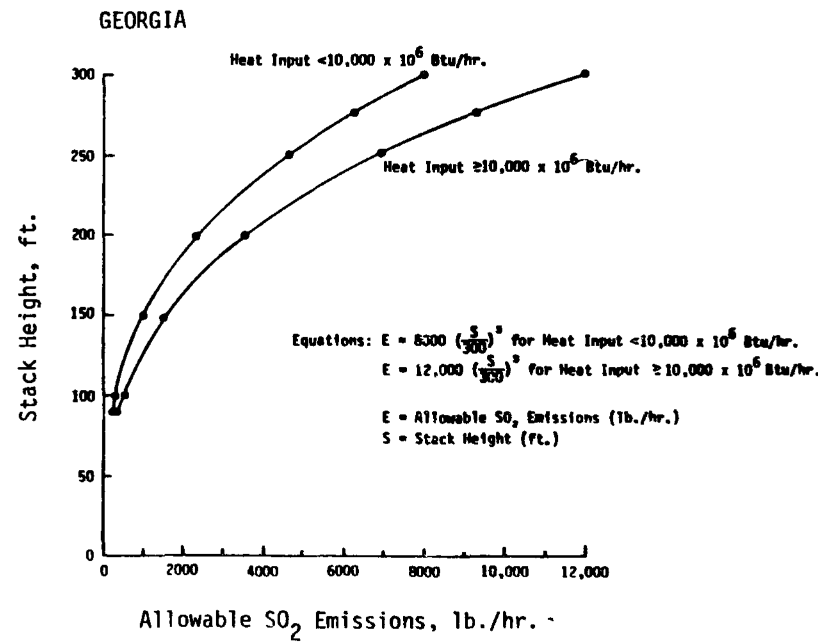

Figure 7. Determination of SO_2 Emission Rate for Stack Heights $\geq$ 90 ft. but < 300 ft.

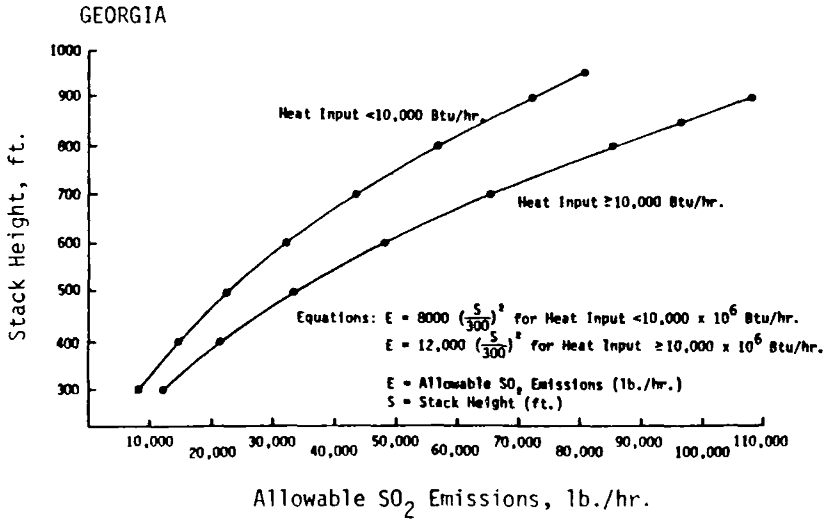

Figure 8. Determination of SO_2 Emission Rate for Stack Heights >300 ft.

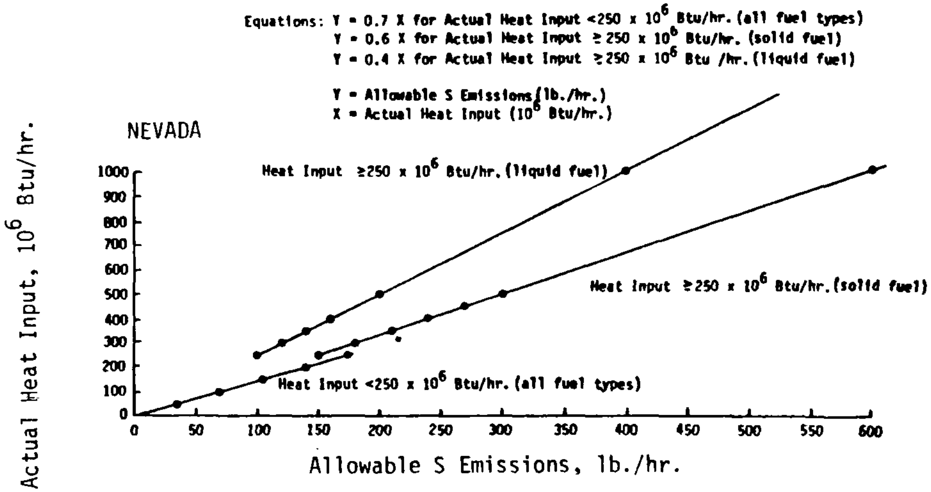

Figure 9. Determination of Sulfur Emission Rate by Actual Heat Input.

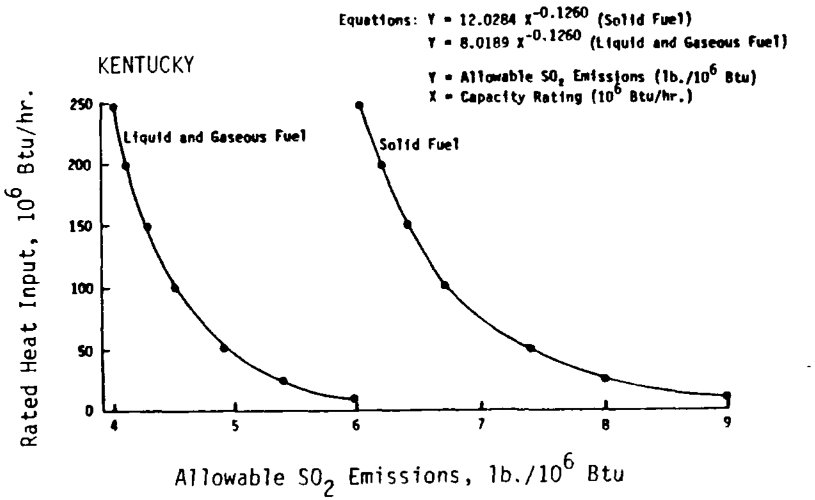

Figure 10. Determination of SO_2 Emission Rate for Existing Sources in County Classification V (All other Counties).

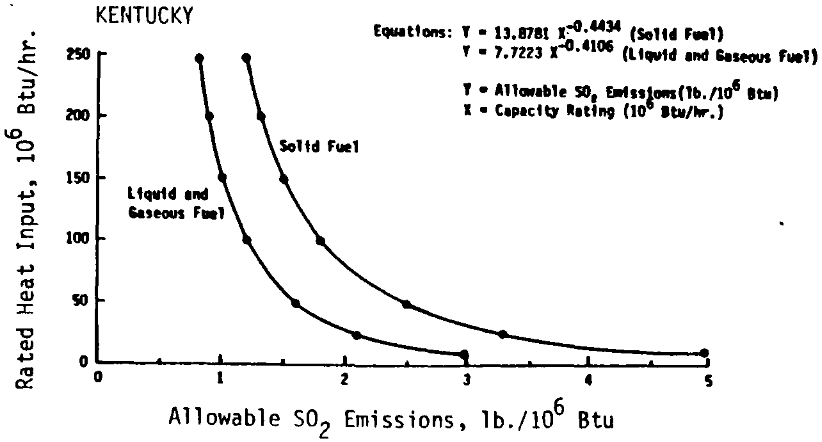

Figure 11. Determination of SO_2 Emission Rate for New Sources by Heat Inpu

Allowable emission rates (lb SO_2/mm Btu) in Kentucky vary with the location (county), facility size (total plant heat input) and type fuel (solid or liquid). The emission rates are determined by equations (Figures 10 and 11) for facilities larger than 10 mm Btu/hr and smaller than 250 mm Btu/hr. Compliance is determined by stack testing using EPA Method 6.

SO_2 emission concentrations in Louisiana, the State of Washington, and Alaska are limited to $\leq$2000 ppm, $\leq$1000 ppm, and $\leq$500 ppm, respectively. These limits apply in all locations, to all size furnaces and all fuels in each case.

3.3 - NEW SOURCE PERFORMANCE STANDARDS

EPA has promulgated standards of performance for the following two classes of steam generating units:

Affected Facility	Standard for Sulfur Dioxide
Electric Utility Steam Generating Units Capable of Combusting >250 mm Btu/hr (which commenced construction after 9/18/78)	(a) Solid fuels or solid-derived fuels: (i) Continental States: <1.2 lb SO_2/mm Btu and <10 percent of the potential combustion concentration of SO_2 or <30 percent of the potential combustion concentration when emissions are <0.60 lb SO_2/mm Btu. (ii) Noncontinental States and Territories: <1.2 lb SO_2/mm Btu (b) Liquid or Gaseous Fuels: (i) Continental States: <0.80 lb SO_2/mm Btu and <10 percent of the potential combustion concentration or 100 percent of the potential combustion concentration when emissions are <0.20 lb SO_2/mm Btu.

(ii) Noncontinental States and Territories: <0.80 lb SO_2/mm Btu

(c) Solid Solvent Refined Coal (SRC-I): <1.2 lb SO_2/mm Btu and <15 percent of the potential combustion concentration of SO_2.

(d) 100 percent anthracite coal, and resource recovery facilities: <1.2 lb SO_2/mm Btu.

Fossil-Fuel Fired Steam Generating Units >250 mm Btu/hr (which commenced construction after 8/17/71)

(a) Liquid fossil-fuel or liquid fossil-fuel and wood residue: <0.80 lb SO_2/mm Btu.

(b) Solid fossil-fuel or solid fossil-fuel and wood residue: <1.2 lb SO_2/mm Btu.

Subpart Da was designed to update (and supersede) Subpart D for electric utility boilers in accordance with the 1977 Amendments to the CAA. Compliance with this regulation is generally determined by continuously monitoring SO_2 concentrations in the flue gas before and after a flue gas desulfurization system (FGD) and calculating the arithmetic average of all hourly emission rates (lb SO_2/mm Btu) for 30 successive days of normal operation.

Subpart D is applicable to all fossil-fuel fired steam generating units and all fossil-fuel and wood residue fired steam generating units capable of burning more than 250 mm Btu/hr of fuel, irrespective of the use of the steam produced. Compliance with the emission limit is determined by continuously monitoring the flue gas and calculating an arithmetic average of the SO_2 emission rate (lb SO_2/mm Btu) for three contiguous one-hour periods.

Appendix A is a copy of sections of 40 CFR 60 pertaining to these NSPS.

Section 4

CONTROL OF SO_2 EMISSIONS

4.1 - NATURAL LOW SULFUR FUELS

State SO_2 emission limits have generally been met by burning fuels with sulfur contents low enough to avoid exceeding the standard. The demonstrated coal reserve base of the United States on January 1, 1974 was estimated at 437 billion tons. About half of this reserve base can be assumed to be recoverable. About 46 percent of the reserve base has an average sulfur content of 1 percent or less which could meet an SO_2 emission limit of 1.5 lb/mm Btu. Another 21 percent of the reserve base has an average sulfur content between 1 and 3 percent. This coal could be used to meet SO_2 limits between 1.5-5 lb/mm Btu. The average sulfur content of another 21 percent of the reserve base is greater than 3 percent and the remaining 12 percent of the reserve base has not been classified.

4.2 - PHYSICAL COAL CLEANING

Physical coal cleaning can increase the amount of coal available to meet a low SO_2 emission limit in the following ways. Sulfur in coal is either chemically bonded with the carbon or in the form of pyrite. About 50 percent of the pyritic sulfur can be removed by physically cleaning the coal. This is accomplished by crushing the coal and removing the pyrite by gravity separation. The total sulfur content of the coal can be reduced 14-45 percent by physical cleaning. Since ash is also removed by the washing process, the heating value of the coal (Btu/lb) is increased. Therefore, the SO_2 emission potential per Btu of fuel burned (lb SO_2/mm Btu) can be reduced 24 to 50 percent.

In addition to reducing the SO_2 emission potential of a coal, physical cleaning reduces the variability of the sulfur content and the heating value. Therefore, the resulting coal should have a more constant emission rate (lb SO_2/mm Btu).

4.3 - OIL CLEANING

The sulfur content of fuel oil can be substantially reduced by hydrotreating or hydrodesulfurization. These are chemical processes which involve contact of the oil with a catalyst and hydrogen to convert the sulfur to gaseous hydrogen sulfide (H_2S).

In a typical hydrotreating or hydrodesulfurization process, oil is filtered to remove rust, coke and other suspended material. It is then mixed with hydrogen, heated to 340 to 450^oC (650^o to 850^oF), and passed over one or more catalytic reaction beds. The most widely used catalysts are composites made up of cobalt oxide, molybdenum oxide, and alumina, where alumina is the support and the other agents are promoters. This process can reduce the sulfur content of a 2 percent sulfur residual oil feedstock by 50 percent, to 1 percent sulfur. To produce a lower sulfur content product, additional catalytic reaction stages must be added. A system with two catalytic reaction stages can produce a fuel of approximately 0.3 percent sulfur content from a 2 percent sulfur feedstock. A more advanced process using three catalytic reactors can produce fuel oils with sulfur contents as low as 0.1 percent.

4.4 - FLUE GAS DESULFURIZATION

To meet SO_2 limits below 1 lb/mm Btu, it may be necessary to remove SO_2 from the exhaust gas after combustion. This can be accomplished by scrubbing the gas with chemical solutions, such as sodium hydroxide or sodium carbonate (sodium and double alkali processes); calcium oxide or calcium carbonate; (lime and limestone processes).

In each case a chemical reaction combines the SO_2 in the flue gas with the reactant to form a precipitant which separates from the air stream. Performance data from several operating facilities show the following ranges of SO_2 removal efficiencies:

Sodium scrubbing - 90-95 percent removal for facilities burning coal or oil with up to 3 percent sulfur.

Double alkali - 90-95 percent removal for facilities burning coal with up to 3.2 percent sulfur.

Lime - 88-95 percent removal for facilities burning coal with up to 3.6 percent sulfur.

Limestone - 70-90 percent removal.

Limestone with 2500 ppm adipic acid - an average of 93 percent removal was achieved for a facility burning coal with up to 3.6 percent sulfur.

Dry scrubbing - 75 percent removal has beeen guaranteed for coal with up to 3 percent sulfur. Eighty-five (85) percent removal has been guaranteed for coal with 1 to 2 percent sulfur.

Section 5

INDIVIDUAL STATE'S SIP REGULATIONS

The SO_2 emission regulations applicable in each State are delineated in the following pages. The States are presented alphabetically by EPA Region number.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 1	STATE: Connecticut	REGULATION: State Air Law 19-508-19

APPLICABILITY: Area New/Existing	Statewide Uncontrolled[a], New & Existing, Comply by 9/1/72	Statewide controlled[a], New & Existing, Comply by 9/1/72	Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	All	>250
FUEL TYPE	All fossil	All fossil fuels with >0.5% S	NSPS, See Appendix A
EMISSIONS LIMIT	≤0.5% S, dry basis determination	≤0.55 lbs. SO_2/MMBtu	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2b, 2c, 3d, 4a, 5b, 5d		1a, 2a, 2b, 2c, 3a, 4a, 5a, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) or manufacturer's, whichever is greater
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM D3176 (coal or solid)
      ASTM D129 (residual or liquid) or D1552
      ASTM D129 (distillate or liquid) or D1552
      other:
   c. other testing: stack testing by Commissioner's request only if uncontrolled source has potential to emit ≥100 tons SO_2/yr.

[a]refers to source using or not using a stack-gas cleaning process, controlled or uncontrolled, respectively.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: continuous SO_2 monitoring by Commissioner's request

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 19-508-4 (periodic reports); and Section 19-508-7 (equipment malfunction)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 1	STATE: Maine	REGULATION: Title 38, Section 603

APPLICABILITY: Area[a]	1, 2, 3, 4	5, 6	7	7	Statewide
New/Existing Compliance Date	New & Existing After 11/1/73	New & Existing After 6/1/75	New & Existing After 11/1/75	New & Existing After 11/1/85	New after 8/17/71 or 9/18/78 (NSPS) N.A.
FACILITY SIZE (MMBtu/hr)	All	All	All	All	>250
FUEL TYPE	All fossil	All fossil	All fossil	All fossil	NSPS, See Appendix A
EMISSIONS LIMIT	$\leq$2.5% S	$\leq$2.5% S	$\leq$1.5% S	$\leq$1.0% S	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1e, 2c, 3d, 4d, 5b				1a, 2a, 3a, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: not specified

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: specified by the Board

[a]1--Central Maine; 2--Down east; 3--Aroostook county; 4--Northwest Maine; 5--Metropolitan Portland; 6--Outside Portland Peninsula; 7--Inside Portland Peninsula.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Board

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 589 (monthly reports of total volume of blended oils and averages. Also quantity of solid & liquid fuel imported into the state.
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 1 STATE: Massachusetts REGULATION: 310 CMR 7.05

APPLICABILITY: Area[a] New/Existing	B New & Existing		CM, MV, MB[b], PV, SM New & Existing		MB (specific cities[d]) New & Existing		Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All		All		All		>250
FUEL TYPE	#2 fuel oil	all other fossil	#2 fuel oil	all other fossil	#2 fuel oil	all other fossil	NSPS, See Appendix A
EMISSIONS LIMIT	<0.17 lbs S/MMBtu	<1.21 lbs S/MMBtu	<0.17 lbs S/MMBtu	<0.55 lbs S/MMBtu	<0.17 lbs S/MMBtu	<0.28 lbs S/MMBtu	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4d, 5b, 5d						1a, 2a, 3a, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. *total plant design rated (MMBtu/hr)*
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: specified by the Department (methods and frequency of testing)

Footnotes: See page 2, Massachusetts

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. *sulfur content of fuel*
   d. other: specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Department

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 310 CMR 7.12. Annual report for sources emitting <100 tons SO_2/yr. Semi-annual report for sources emitting $\geq$100 tons SO_2/yr.
   c. specified in 40 CER Part 51 (see Appendix B)
   d. specified by the Director

EPA Region: 1 State: Massachusetts (continued)

Footnotes:

[a]B = Berkshire
CM = Central Massachusetts
MV = Merrimark Valley
MB = Metropolitan Boston
PV = Pioneer Valley
SM = Southeastern Massachusetts

[b]All cities except those specified later.

[c]Not applicable.

[d]Medford, Newton, Somerville, Walthon and Watertown.

[e]Refers to all size sources except that units having rated heat input capabilities ≥ 3 MMBtu/hr cannot use residual fuel.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 1	STATE: New Hampshire	REGULATION: Air Pollution Control Commission No. 5, Revision III

APPLICABILITY:		
Area[a]	Statewide	
New/Existing	New and Existing	
Other		
FACILITY SIZE (MMBtu/hr)	All	All
FUEL TYPE	Solid fossil	Gaseous fossil
EMISSIONS LIMIT	$\leq$ 2.8 lbs. S/MMBtu gross heat content[b] and $\leq$ 2.0 lbs. S/MMBtu gross heat content, (3 month average)	$\leq$ 5 gr. H_2S/100 cu. ft.
COMPLIANCE PROCEDURES (1-5, listed below)	1e, 2b, 2c, 3d, 4d, 5b	

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: not specified for compliance purposes

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: most recent ASTM method (at Agency's request)
   c. other testing: not specified

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: not specified

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: tri-monthly weighted average of fuel S content

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: No. 5, Revision III, Section 5 (fuel analysis at Agency's request)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, New Hampshire

SO$_2$ EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 1	STATE: New Hampshire (continued)	REGULATION: Air Pollution Control Commission No. 5, Revision III

APPLICABILITY: Area[a] New/Existing	Statewide New and Existing			Statewide New after 4/15/80	AV[a] New and Existing
FACILITY SIZE (MMBtu/hr)	All			All	All
FUEL TYPE	#2 fuel oil	#4 fuel oil	#5 & #6 fuel oil	Solid fossil	All fossil
EMISSIONS LIMIT	$\leq$ 0.4% S	$\leq$ 1.0% S	$\leq$ 2.0% S	$\leq$ 1.5% lbs. S/MMBtu gross heat content[b]	$\leq$ 2.2% S
COMPLIANCE PROCEDURES (1-5, listed below)	1e, 2b, 2c, 3d, 4d, 5b				

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: not specified for compliance purposes

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: most recent ASTM method (at Agency's request)
   c. other testing: not specified

3. MONITORING REQUIREMENTS:
   a. continuous SO$_2$ monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: not specified

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: tri-monthly weighted average of fuel S content

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: No. 5, Revision III, Section 5 (fuel analysis at Agency's request)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, New Hampshire

EPA Region: 1 State: New Hampshire

Footnotes:

[a]Refers to "Air Quality Control Region": AV = New Hampshire portion of Androscoggin Valley AQCR.

[b]Refers to maximum value.

SO$_2$ EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 1	STATE: Rhode Island	REGULATION: Air Pollution Control Regulation No. 8

APPLICABILITY:		
Area	Statewide	Statewide
New/Existing	New and Existing	New and Existing
Other	All uncontrolled sources[a]	All approved controlled sources[b]
FACILITY SIZE (MMBtu/hr)	All	All
FUEL TYPE	All fossil	Any fossil fuel with >0.55 lbs S/MMBtu (heat release potential).
EMISSIONS LIMIT	Requires use of fuels with $\leq$ 0.55 lbs S/MMBtu (fuel heat release potential) or $\leq$ 1.1 lb SO$_2$/MMBtu	$\leq$ 1.1 lbs SO$_2$/MMBtu actual heat input
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2b, 2c, 3d, 4d, 5b	

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) or manufacturer, whichever is greater
   b. unit actual or operating (MMBtu/hr)[c]
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:

   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: collection for testing when specified by the Director.

   c. other testing:

      specified by the Director when he has reason to believe noncompliance.

3. MONITORING REQUIREMENTS:
   a. continuous SO$_2$ monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: not specified

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Director

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: (Annual reports on fuel usage, stack dimensions, exhaust gas flow rate and temperature, generating capacities of generators, air pollution control systems, type of emissions, and pollution emitting equipment.
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 2, Rhode Island

EPA region: 1 State: Rhode Island (continued)

Footnotes:

[a]Refers to source using no stack gas cleaning device.

[b]Refers to source using a stack gas cleaning process to reduce the SO_2 emissions provided equivalent emissions do not exceed specified emission limitations.

[c]Actual heat input = heating value of fuel x quantity of fuel burned (ton/hr).

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 1	STATE: Vermont	REGULATION: Environmental Protection Regulations Chapter 5, Subchapter II, Sec. 221 and Section 252

APPLICABILITY:				
Area	Statewide	Statewide	Statewide	
New/Existing	New and Existing	New and Existing	New and Existing	
Other	Uncontrolled	Controlled	N.A.	
FACILITY SIZE (MMBtu/hr)	$\leq$ 250	$\leq$ 250	> 250	
FUEL TYPE	All fossil	All fossil	Liquid fossil	Solid fossil
EMISSIONS LIMIT	$\leq$ 2% S	SO_2 emissions (lbs. SO_2/MMBtu equivalent to those when using $\leq$ 2 % S fuel)	0.80 lbs SO_2/MMBtu	1.2 lbs SO_2/MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 3b, 3c, 3d, 4a, 5b, 5d			

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) (maximum)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: at request of the Director, Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing:

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate at Director's request
   c. sulfur content of fuel
   d. other: as required by the Air Pollution Control Officer

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 5, Section 402 (written reports)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director: fuel type, quantity, nature and amount of emissions, and other relevant information such as stack testing

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 2	STATE: New Jersey	REGULATION: Title 7, Chapter 27, Subchapter 9 & 10

APPLICABILITY: Area[a] New/Existing	Zone 1 & 2 New & Existing	Zone 3 & 4 New & Existing	Zone 1 & 2 New & Existing	Zone 3 & 4 New & Existing	Zone 3 & 4 Existing on or before 5/6/68		Statewide (all other zones) New or reconstructed after 5/6/68
FACILITY SIZE (MMBtu/hr)	All	Units < 200 or total facility < 450	All	All	Units > 200 or group of facility > 450		> 1
FUEL TYPE	Bituminous coal	Bituminous coal	Anthracite coal	Anthracite coal	Bituminous coal	Anthracite coal	All coal
EMISSIONS LIMIT	$\leq$ 1.0% S or $\leq$ 1.5 lb SO_2/MMBtu	$\leq$ 0.2% S or $\leq$ 0.3 lb SO_2/MMBtu	$\leq$ 0.7% S or $\leq$ 0.3 lb SO_2 MMBtu	$\leq$ 0.2% S or $\leq$ 0.3 lb SO_2/MMBtu	$\leq$ 1.0% S or $\leq$ 0.3 lb SO_2/MMBtu	$\leq$ 0.2% S or $\leq$ 0.3 lb SO_2/MMBtu	$\leq$ 0.2% S or $\leq$ 0.3 lb SO_2/ MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1c, 2c, 3d, 4d, 5b						

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:

   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: specified by the Department

   c. other testing: specified by the Department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Department

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: subchapter 10.2 & 9.2

   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, New Jersey

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 2 STATE: New Jersey (continued) REGULATION: Title 7, Chapter 27, Subchapters 9 & 10

APPLICABILITY:	Zone 1		Zone 2 & 5			Zone 3 & 4 & 6		Zone 3	Zone 4 & 6
Area[a]									
New/Existing	New & Existing		New & Existing			New & Existing		New & Existing	New & Existing
FACILITY SIZE (MMBtu/hr)	All		All			All		All	All
FUEL TYPE	fuel oil		fuel oil			fuel oil		fuel oil	fuel oil
	≤ #2	≥#4, #5, #6	≤#2	#4	≥#5, #6	≤#2	#4	≥#5, #6	≥#5, #6
EMISSIONS LIMIT	0.3% S	2.0% S or ≤2.1 lb SO_2/MMBtu	0.3% S	0.7% S, ≤0.74 lb SO_2/MMBtu	1.0% S, ≤1.05 lb SO_2/MMBtu	0.2% S	0.3% S or ≤0.32 lb SO_2/MMBtu	0.5% S or ≤0.53 lb SO_2/MMBtu	0.3% S or ≤0.32 lb SO_2/MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1c, 2c, 3d, 4d, 5b								

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: specified by the Department
   c. other testing: specified by the Department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Department

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: subchapter 10.2 & 9.2
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, New Jersey

EPA region: 2 State: New Jersey (continued)

Footnotes:

[a]Zone 1 - Atlantic, Cape May, Cumberland, and Ocean Counties
Zone 2 - Hunterdon, Sussex, and Warren Counties
Zone 3 - Burlington, Camden, Gloucester, and Mercer counties (except those municipalities included in Zone 6)
Zone 4 - Bergen, Essex, Hudson, Middlesex, Monmouth, Morris, Passaic, Somerset, and Union counties
Zone 5 - Salem County
Zone 6 - in Burlington County, the minicipalities of Bass River, Shamong, Southampton, Tabernacle, Washington, Woodland, and in Camden County, Waterford Township

[b]Refers to dry basis determination

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SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 2	STATE: New York	REGULATION: Title 6, Part 225

APPLICABILITY: Area	New York City		Nassau, Rockland & Westchester Counties		Suffolk County, Towns of Babylon, Brookhaven, Huntington, Islip, and Smithtown			
New/Existing	New & Existing		New & Existing		New & Existing			
FACILITY SIZE[a] (MMBtu/hr)	All >10		All >10		All Existing[c], New[d] $\leq$250 and >10		New[d] >250	
FUEL TYPE	Residual oil	Distillate[e] & solid fossil fuel	Fuel oil	Solid fossil	Fuel oil	Solid fossil	Fuel oil	Coal
EMISSIONS LIMIT[h]	$\leq$.30% S	$\leq$.20% S	$\leq$.37% S	$\leq$.20% S	$\leq$1.0% S	$\leq$0.6% S	$\leq$.75% S	$\leq$.60 lb S/MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1d, 2a, 2b, 2c, 3a or 3d, 4a, 4c, 4d, 5b, 5d							

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 at Commissioner's request
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: most recent applicable ASTM methods for sampling, compositing, and analysis of fuel or other methods acceptable to the Commissioner. The following values will be determined: (residual oil) sulfur & ash content, specific gravity, heating value, (distillate oil) sulfur content, specific gravity, heating value, (coal) sulfur & ash content, heating value

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: if total heat input >250 MMBtu/hr: (weekly) gross heat content and ash content of fuel burned. electricity installations : average electrical output & minimum & maximum hourly, (daily) rate of fuel burned

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average) for stack tests
   d. other: 3 continuous 1 hour averages (arithmetic average) for continuous monitoring data as specified in 40 CFR Part 60

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Title 6, Part 225.6(d) and Part 225.7
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director (when to submit report)

Footnotes: See page 3, New York

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 2 STATE: New York REGULATION: Title 6, Part 225

APPLICABILITY: Area New/Existing	Erie & Niagra Counties City of Lakawana & South Buffalo[t] New & Existing			Remainder of Areas New & Existing				Rest of State New & Existing			
FACILITY SIZE[a] (MMBtu/hr)	All Existing,[c] New[d] ≤250 but >10	New[d] >250		All Existing,[c] New[d] ≤250 but >10		New[d] >250		All Existing,[c] New[d] ≤250 but >10		New[d] >250	
FUEL TYPE	Fuel Oil	Fuel Oil	Coal	Fuel Oil	Solid Fossil	Fuel Oil	Coal	Fuel Oil	Solid Fossil	Fuel Oil	Coal
EMISSIONS LIMIT[h]	≤1.1% S	≤.75% S	≤.60 lb S/ MMBtu	≤2.0% S (max.) ≤1.7% S (avg.[f])	≤1.7% S (max.) & ≤1.4% S (avg.[g])	≤.75% S	≤.60 lb S/ MMBtu	≤2.0% S	≤2.5% S (max.) & 1.9% S (avg.[g])	≤.75% S	≤.60 lb S/ MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1d, 2a, 2b, 2c, 3a or 3d, 4a, 4c, 4d, 5b, 5d										

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 at Commissioner's request
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: most recent applicable ASTM methods for sampling, compositing, and analysis of fuel or other methods acceptable to the Commissioner. The following values will be determined: (residual oil) sulfur & ash content, specific gravity, heating value, (distillate oil) sulfur content, specific gravity, heating value, (coal) sulfur & ash content, heating value

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: if total heat input >250 MMBtu/hr: (weekly) gross heat content & ash content of fuel burned. Electricity installations: average electrical output & minimum and maximum hourly, (daily) rate of fuel burned

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 3 continuous 1 hour averages (arithmetic average) for continuous monitoring data as specified in 40 CFR Part 60

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Title 6, Part 225.6(d) and Part 225.7
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director (when to submit report)

Footnotes: See page 3, New York

EPA region: 2 State: New York (continued)

Footnotes:

[a]Determined by product of fuel weight rate (lbs./hr.) and fuel caloric value.

[b]That area located in the City of Buffalo which is south of the line commencing at the intersection of I 190 and Rt. 5 and proceeding east along I 190 to the city line.

[c]Application for permit to construct received on or before 3/15/73.

[d]Application for permit to construct received after 3/15/73.

[e]Refers to ASTM 1 & 2 (fuel oil), 1-D&2-D (diesel fuel oil), and 1-GT&2-GT turbine fuel oil.

[f]Determined by dividing the sum or sulfur content times the amount of each shipment of oil received by the total amount of oil received during each consecutive 3 month period.

[g]Determined by dividing the total sulfur content by the total gross heat content of all solid fuel received during any consecutive 3 month period.

[h]All sources in areas attaining the National Ambient Air Quality Standard for SO_2 March 24, 1979 having a source total heat input $\leq$250 MMBtu/hr. (oil) or <100 MMBtu (individual unit) gross heat input (coal) will be permitted to use oil $\leq$3 percent by weight sulfur or coal $\leq$2.8 lbs. sulfur/MMBtu gross heat input, respectively, as approved by the Commissioner.

Pg. 1

SO_2 EMISSION LIMITATIONS EROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3	STATE: Delaware	REGULATION: VIII, XX (Section 2)

APPLICABILITY: Area New/Existing	New Castle County New & Existing		
FACILITY SIZE (MMBtu/hr)	All		Any facility with SO_2 emission control equipment
FUEL TYPE	Distillate fossil	Other fossil	All fossil
EMISSIONS LIMIT	$\leq$0.3% S	<1.0% S & attain NAAQS	Emission rate equivalent to sulfur limitations
COMPLIANCE PROCEDURES (1-5, listed below)	1e, 2a, 2b, 3d, 4d, 5d		

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr) for testing procedure
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. *other: not specified*

2. TEST METHODS:
   a. source testing: specified by Director

   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: x-ray absorption method (residual or distillate for New Castle County)

   c. other testing: lbs. SO_2/MMBtu total plant actual heat input as specified by the Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 30 day rolling average for emissions limitation

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:

   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3	STATE: Delaware (continued)	REGULATION: VIII, XX (Section 2)

APPLICABILITY: Area New/Existing	 Kent, Sussex Counties New (construction on or after 8/17/71)	 Statewide NSPS, new after 8/17/71 or 9/18/78	 Statewide New & Existing
FACILITY SIZE (MMBtu/hr)	>250	>250	All not previously specified
FUEL TYPE	All fossil	NSPS, see Appendix A	All
EMISSIONS LIMIT	≤1.2 lbs. SO_2/MMBtu	NSPS, see Appendix A	Specified by the Department
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 1b, 1c, 2a, 3d, 4d, 5d	1a, 2c, 3d, 4d, 5d	1e, 2a, 3d, 5d

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: not specified

2. TEST METHODS:
   a. source testing: specified by Director
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: x-ray absorption method (residual or distillate for New Castle County)
   c. other testing: lbs. SO_2/MMBtu total plant actual heat input as specified by the Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 30 day rolling average for emissions limitation

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3	STATE: Maryland	REGULATION: 10.18.09

APPLICABILITY: Area - County[a] New/Existing	I, II, V, VI New & Existing			
FACILITY SIZE (MMBtu/hr)	≥13			>13 unit actual and ≥100 total plant design capacity
FUEL TYPE	residual fuel oil	distillate fuel oil	process gas used as fuel	solid fossil
EMISSIONS LIMIT	2.0% S	0.3% S	0.3% S	3.5 lbs SO_2/MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4a, 5b, 5d			1b, 1c, 2c, 3d, 4a, 5d

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: ____________________
   c. other testing: Method 6 in "Test Methods for Stationary Sources", Maryland State Bureau of Air Quality and Noise Control, March 1976. Test methods may be modified by the Department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: as requested by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director (fuel analysis, type & quantity for owner and fuel supplier)

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3	STATE: Maryland (continued)	REGULATION: 10.18.09

APPLICABILITY:				
Area - County[a]	III & IV			Statewide
New/Existing	New & Existing			NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (Heat input in MMBtu/hr)	$\geq$13		$\geq$250	>250
FUEL TYPE	residual fuel oil	distillate fuel oil	solid fossil	NSPS, see Appendix A
EMISSIONS LIMIT	1.0% S	0.3% S	1.0% S	NSPS, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4a, 5d			1a, 2a, 3a, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: ____________
   c. other testing: Method 6 in "Test Methods for Stationary Sources", Maryland State Bureau of Air Quality and Noise Control, March 1976. Test methods may be modified by the Department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: as requested by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director (fuel analysis, type & quantity for owner and fuel supplier)

EPA region: 3 State: Maryland (continued)

Footnotes:

[a]Area I - Alleghany, Garrett & Washington counties
Area II - Frederick county
Area III - Baltimore city, Anne, Arundell, Baltimore, Carroll, Harford & Howard counties
Area IV - Montgomery & Prince George counties
Area V - Calvert, Charles, & St. Mary counties
Area VI - Caroline, Cecil, Dorchester, Kent, Queen Anne, Somerset, Talbot, Wiconico, & Worcester counties

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3	STATE: Pennsylvania	REGULATION: Title 25, Part I, Subpart C, Article III, Chapter 123.22

APPLICABILITY:										
Area - Air Basin[a]	I		II		III			IV		
New/Existing	New & Existing		New & Existing		New & Existing			New & Existing		
Compliance Date	N.A.[d]		N.A.		8/1/79	8/1/79	8/1/82	N.A.		
FACILITY SIZE (MMBtu/hr)	All		All		All	All	All	>2.5 but <50	≥50 but ≤2,000	≥2,000
FUEL TYPE	Fuel oil ≤#2	Fuel oil ≥#4, 5, 6	Fuel oil ≤#2	Fuel oil ≥#4, 5, 6	Fuel oil ≤#2	Fuel oil #4, 5, 6		All fuel oil	All fuel oil	All fuel oil
EMISSIONS LIMIT lbs SO_2/MMBtu	≤0.5% S	≤2.8% S	≤0.3% S	≤2.8% S	≤0.3% S	≤2.0% S	≤1.5% S	1.0 & (0.5)[i] lb SO_2/MMBtu		
	or ≤4.0 lb SO_2/MMBtu		or ≤4.0 lb SO_2/MMBtu		or ≤3.0 lb SO_2/MMBtu					
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2b, 2c, 3d, 4b, 5b, 5d									

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: determination of F-Factor only from 40 CFR Part 60 (Method 6)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: as specified by the Director
   c. other testing: stack testing (when specified by the Director) by 1) Devorkin, "Air Pollution Source Testing Manual" L.A.P.C.D. 2nd printing, 11/65 or 2) equivalent method-Robert Hilvinsky, "Determination of sulfur oxides" (utilizing isopropyl alcohol and sodium hydroxide), Air Pollution Source Testing Manual, Method 5.4, South Coast Air Quality Management District, El Monte, California, 2nd printing, 8/78

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) (for continuous SO_2 data)
   b. 1 hour (for compliance stack testing)
   c. 2 hours (arithmetic average)
   d. other: 30 day, 1 day, & daily maximum (for continuous monitoring data)

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 139.1022
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3 STATE: Pennsylvania (continued) REGULATION: Title 25, Part I, Subpart C, Article III, Chapter 123.22

APPLICABILITY: Area - Air Basins[a] New/Existing	V (Inner zone) New & Existing		V (Outer zone) New & Existing		V (Inner zone) New & Existing		V (Outer zone) New & Existing	
FACILITY SIZE (MMBtu/hr)	<250		<250		<250		<250	
FUEL TYPE	Fuel oil		Fuel oil		Fuel oil		Fuel oil	
	≤#2	≥#4, 5, 6	≤#2	≥#4, 5, 6	≤#2	≥#4, 5, 6	≤#2	≥#4, 5, 6
EMISSIONS LIMIT lbs SO_2/MMBtu	≤0.2% S	≤0.5% S	≤0.3% S	≤1.0% S	≤0.2% S	≤0.5% S	≤0.3% S	≤1.0% S
	or ≤1.0 lb SO_2/MMBtu		or ≤1.2 lb SO_2/MMBtu		or ≤0.6 lb SO_2/MMBtu		or ≤1.2 lb SO_2/MMBtu	
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2b, 2c, 3d, 4b, 5d							

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: determination of F-Factor only from 40 CFR Part 60 (Method 6)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: as specified by the Director
   c. other testing: stack testing (when specified by the Director) by 1) Devorkin, "Air Pollution Source Testing Manual" L.A.P.C.D. 2nd printing, 11/65 or 2) equivalent method-Robert Hilvinsky, "Determination of sulfur oxides" utilizing isopropyl alcohol and sodium hydroxide), Air Pollution Source Testing Manual, Method 5.4, South Coast Air Quality Management District, El Monte, California, 2nd printing, 8/78

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) (for continuous SO_2 data)
   b. 1 hour (for compliance stack testing)
   c. 2 hours (arithmetic average)
   d. other: 30 day, 1 day, & daily maximum (for continuous monitoring data)

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 139.1022
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3	STATE: Pennsylvania (continued)	REGULATION: Title 25, Part I, Subpart C, Article III, Chapter 123.22

APPLICABILITY: Area - Air Basins[a] New/Existing	I & II New & Existing			III New & Existing			V (inner zone) New & Existing					
FACILITY SIZE (MMBtu/hr)	All[g]			All[g]			< 250		≥250			
FUEL TYPE	Solid fossil			Solid fossil			Solid fossil		Solid fossil			
EMISSIONS LIMIT lbs SO_2/MMBtu	≤3.7 (30 day avg.)	≤4.0 (1 day[h] avg.)	≤4.8 1 day (max.)	≤2.8 (30 day avg.)	≤3.0 (1 day avg.)	≤3.6 1 day (max.)	≤0.75 (30 day avg.)	≤1.0 (1 day[h] avg.)	≤1.2 1 day (max.)	≤0.45 (30 day avg.)	≤0.60 (1 day[h] avg.)	≤0.72 1 day (max.)
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2b, 2c, 3a, 4b, 4d, 5b, 5c											

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: determination of F-Factor only from 40 CFR Part 60 (Method 6)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: as specified by the Director

   c. other testing: stack testing (when specified by the Director) by 1) Devorkin, "Air Pollution Source Testing Manual" L.A.P.C.D. 2nd printing, 11/65 of 2) equivalent method-Robert Hilvinsky, "Determination of sulfur oxides" (utilizing isopropyl alcohol and sodium hydroxide), Air Pollution Source Testing Manual, Method 5.2, South Coast Air Quality Management District, El Monte, California, 2nd printing, 8/78

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) (for continuous SO_2 data)
   b. 1 hour (for compliance stack testing)
   c. 2 hours (arithmetic average)
   d. other: 30 day, 1 day & daily maximum (for continuous monitoring data)

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 139.1022
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 5, Pennsylvania

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3	STATE: Pennsylvania (continued)	REGULATION: Title 25, Part I, Subpart C, Article III, Chapter 123.22

APPLICABILITY: Area - Air Basins[a]	V (outer zone)		
New/Existing	New & Existing		
FACILITY SIZE (MMBtu/hr)	All		
FUEL TYPE	Solid fossil		
EMISSIONS LIMIT lbs SO_2/MMBtu	≤ 0.90, (30 day avg.)	≤ 1.2, (1 day[h] avg.)	≤ 1.44, 1 day (max.)
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2b, 2c, 3a, 4b, 4d, 5b, 5c		

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: determination of F-Factor only from 40 CFR Part 60, (Method 6)
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: as specified by the Director

   c. other testing: stack testing (when specified by the Director) by 1) Devorkin, "Air Pollution Source Testing Manual" L.A.P.C.D. 2nd printing, 11/65 or 2) equivalent method-Robert Hilvinsky, "Determination of sulfur oxides" (utilizing isopropyl alcohol and sodium hydroxide), Air Pollution Source Testing Manual, Method 5.4, South Coast Air Quality Management District, El Monte, California, 2nd printing, 8/78

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) (for continuous SO_2 data)
   b. 1 hour (for compliance stack testing)
   c. 2 hours (arithmetic average)
   d. other: 30 day, 1 day, & daily maximum (for continuous monitoring data)

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 139.1022
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:

[a]I = non-air basin areas.
II = Erie, Harrisburg, York, Lancaster, Scranton, Wilkes-Barre.
III = Allentown, Bethlehem, Easton, Reading, Upper Beaver Valley, Johnston.
IV = Alleghany County, Beaver Valley, Monongahela Valley.
V = Southeast Pennsylvania - Inner & Outer refer to zoning classifications within the air basin

[b]Refers to "Fossil Fuel Fired" units not using coal.

[c]Refers to zone within specified air basin.

[d]N.A. = not applicable.

[e]Refers to formula for determining emission rate, $A = 1.7E^{-0.14}$

where: A = allowable SO_2 emissions (lbs/MMBtu heat input)
E = heat input to the combustion unit in MMBtu/hrs

[f]Specified sulfur content refers to facilities not using SO_2 pollution abatement devices to achieve compliance. Controlled sources may use higher sulfur content fuel if meet lbs SO_2/MMBtu limitation.

[g]By department approval only.

[h]Except for 2 days/month.

[i]Alleghany County only.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3 STATE: Virginia REGULATION: Air Pollution Control Board, Part IV, Rule Ex-5, Section 4.51

APPLICABILITY: Area - AQCR[a] New/Existing	1, 2, 3, 4, 5, 6 New & Existing	7 New & Existing			Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	All			>250
FUEL TYPE	All fossil	Solid fossil	Liquid or Gaseous fossil	Combination liquid & solid fossil	NSPS, see Appendix A
EMISSIONS LIMIT[b]	S = 2.64(k)	S = 1.52(k)	S = 1.06(k)	$PS = K \left(\frac{X(1.06) + Y(1.52)}{X + Y}\right)$	NSPS, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 2a or 2c, 3d, 4a or 4d, 5b, 5d				1b, 2a, 3a, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) at total capacity
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: 3 separate runs of Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: as approved by the Board (3 separate runs)

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Board

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified in alternative approved test method

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Part IV, Section 4.05 (monitoring & test results)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director (provide reports at his request)

Footnotes: See page 2, Virginia

EPA region: 3 State: Virginia (continued)

Footnotes:

[a]Refers to Air Quality Control Region (by counties & cities) listed in Appendix B, page 195 of Commonwealth of Virginia Regulations for the Control and Abatement.

1 - Eastern Tennessee - Southwestern Virginia
2 - Valley of Virginia
3 - Central Virginia
4 - Northeastern Virginia
5 - State Capital
6 - Hampton Roads
7 - National Capital

[b]Where:

S = Allowable SO_2 emissions in lbs/hr.
k = Actual heat input at maximum capacity.
PS = Prorated allowable SO_2 emissions in lbs/hr.
X = Percentage of actual heat input derived from liquid or gaseous fuel.
Y = Percentage of actual heat input derived from solid fuel.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3	STATE: Washington, D.C.	REGULATION: Section 8-2.704 & 2.705

APPLICABILITY: Area New/Existing	 Statewide New & Existing	 Statewide NSPS, new after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	>250
FUEL TYPE	All fossil	NSPS, see Appendix A
EMISSIONS LIMIT	$\leq$1.0% S	NSPS, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2b, 2c, 3a, 3c, 3d, 4c, 5b, 5d	1a, 2a, 2b, 2c, 3a, 3c, 3d, 4a, 4d, 5a, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: 40 CFR 60.45.f.5. Sulfur content, heat content, viscosity, carbon residue
   c. other testing: specified by the Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A) (sources emit >100 tons/yr SO_2)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: quantity of fuel

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: weekly sulfur content

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 8-2.717 (power plants) weekly, monthly; quarterly, (all other sources), annual (government boilers)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 3 STATE: West Virginia REGULATION: X (1978A)

APPLICABILITY: Area[a & b] New/Existing	I & II: A(a) New & Existing	I & II: A(c) & A(d) New & Existing	I & II: B&C New & Existing	I & II: A(b) New & Existing	III: A(f), A(g), A(i), B&C New & Existing	III: A(e) New & Existing	III: A(h) New & Existing	IV: A(j), A(k), & (B&C)[c] New & Existing
FACILITY SIZE (MMBtu/hr)	≥10		≥10		≥10	≥10	≥10	≥10
FUEL TYPE	All fossil		All fossil		All fossil	All fossil	All fossil	All fossil
EMISSIONS LIMIT lb SO_2/MMBtu	≤6.8	≤2.7	≤3.1	≤7.5	≤3.2	≤5.12	≤3.1	≤1.6
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 1c, 2b, 3a, 3d, 4d, 5b, 5d							

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr), footnote b
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:

   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: equivalent fuel sulfur content to achieve compliance
   c. other testing:

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A) at Director's request
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: not specified

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: continuous 24 hr. average of SO_2 data

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 6.05 (not to exceed one hourly violation per month)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 2, West Virginia

EPA region: 3 State: West Virginia (continued)

Footnotes:

[a]<u>Priority Regions</u>:
I & II - Brooke, Hancock, Marshall, Ohio, Grant (union district only),
Mineral (Elk, New Creek and Piedmont districts) counties.
III except IV - Jackson, Pleasants, Tyler, Wetzel & Wood counties.
IV - All other counties.
<u>Type Equipment</u>:
A - Fuel burning units which produce electricity for sale.
B - Any unit not classified as Type A or C.
C - Any hand-fired or stoker-fired unit not classified as Type A unit.

[b]Refers to specific source or similar units in that Priority Region:
(a) Kammer; (b) Mitchell; (c) Willow Island; (d) Mt. Storm; (e) Harrison; (f) Rivesville; (g) Albright; (h) Fort Martin; (i) Philip Sporn; (j) John Amos; (k) Kanawha

[c]B&C provided $\leq$5,500 lbs. SO_2/hr, discharged from all stacks at one plant.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4	STATE: Alabama	REGULATION: Air Pollution Control, Chapter 5, Section 1

APPLICABILITY:				
Area	Class I[a] or Jefferson Co.	Class II[a]	Jackson Co.	Statewide
New/Existing	New & Existing	New & Existing	New & Existing	NSPS, new after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	All	>5,000	>250
FUEL TYPE	All fossil	All fossil	All fossil	NSPS, see Appendix A
EMISSIONS LIMIT lbs SO_2/MMBtu	$\leq$1.8	$\leq$4.0	$\leq$1.2	NSPS, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1c, 2a or 2c, 3b, 3c, 3d, 4d, 5b			1a, 2a, 3a, 3b, 3c, 4a, 4d, 5a, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr) see footnote b
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: as approved by the Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate (if total rated capacity heat input >1500 MMBtu/hr
   c. sulfur content of fuel
   d. other: as specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 24 hr average for compliance (for SO_2) data or specified by the Director

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 1.7.2 (periodic reports on emission rates (24 hour averages summarized monthly and submitted biannually), sulfur content of fuels

Footnotes: See page 2, Alabama

EPA Region: 4 State: Alabama (continued)

Footnotes:

[a]Refers to counties classified as Class I or Class II in the State of Alabama Air Pollution Control Commission's Rules and Regulations, App. B, page 1 (February 13, 1980).

[b]Units constructed that are applicable NSPS sources are not included in the total rated capacity heat input for the installation.

[c]Refers to maintenance of "National Ambient Air Quality Standard" for SO_2.

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SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4	STATE: Florida	REGULATION: Chapter 17-2.05, Supplement #97

APPLICABILITY: Area New/Existing	Statewide Existing[a]		Statewide New & Existing[a]	Statewide NSPS, new after 8/1/7/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	>250		≤250	>250
FUEL TYPE	Solid fossil	Liquid fossil	All fossil	See Appendix A
EMISSIONS LIMIT lbs SO_2/MMBtu	≤6.17	≤2.75	BACT[b]	See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 2c, 3a, 3d, 4c & 4a, 5a, 5b		1b, 2c, 3d, 4c, 5b	1a, 2a, 3a, 4a, 4c, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: see attachment (page 2)

Footnotes: See page 2, Florida

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)[c]
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)[c]
   b. state regulation: Chapter 17-2.08(2) Supplement 101[d]
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

EPA region: 4 State: Florida (continued)

Footnotes:

[a]Excludes sources and counties containing source specific emissions limitations.

[b]Refers to use of "Best Available Control Technology" to limit emissions.

[c]Refers only to sources with SO_2 pollution control equipment.

[d]Refers to sources without SO_2 pollution control equipment.

2.c. other testing: source testing according to "Standard Sampling Techniques and Methods of Analysis for Determination of Air Pollutants From Point Sources", June 1975.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS (SIP Regulations)

EPA REGION: 4	STATE: Georgia	REGULATION: Air Quality Control Chapter 391-3-1-2(g)

APPLICABILITY: Area	Statewide				Statewide
New/Existing	New & Existing				NSPS, new after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	<100	$\geq$100	<100	$\geq$100	>250
FUEL TYPE	oil	oil	solid fossil	solid fossil	All fossil
EMISSIONS LIMIT[a]	$\leq$2.5% S	$\leq$3.0% S	$\leq$2.5% S	$\leq$3.0% S	NSPS requirements, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 2b, 3d, 4a, 4d, 5a and 5b				1a, 2a, 2b, 3a, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: % sulfur, heating value & ash content (acceptable ASTM method)
   c. other testing:

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) if heat input >250 MMBtu/hr
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Director

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A) if heat input >250 MMBtu/hr
   b. state regulation: Ch. 391-3-1-6(b)1 Fuel testing as specified by the Director, daily & monthly production rates, hours of operation
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 2, Georgia

EPA Region: 4 State: Georgia (continued)

Footnotes:

[a]Sulfur content is determined on a dry basis. Sources using SO_2 pollution abatement device may use higher sulfur content fuel if emissions are equivalent. In addition to the sulfur in fuel limit, the State limits sulfur dioxide emissions based on stack height and location (urban or rural area). However, EPA has "determined that the sulfur in fuel limit . . . is sufficient standing alone to assure attainment and maintenance of the national air quality standards for SO_2" (41FR35185, August 20, 1976).

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4	STATE: Kentucky	REGULATION: 401KAR 61:015, Section 5

APPLICABILITY:						
Area, (see attachment, pg. 4)	I	II	III	IV & IVA	V & VA	Statewide
New/Existing	Existing (constructed on or before 4/9/79)					Existing (constructed on or before 4/9/72)
FACILITY SIZE (MMBtu/hr)	≤ 10					>10 but ≤ 250
FUEL TYPE	Solid fossil					Solid fossil
	Liquid or gaseous fossil					Liquid or gaseous fossil
EMISSIONS LIMIT lbs SO_2/MMBtu, solid	≤ 5.0	≤ 6.0	≤ 7.0	≤ 8.0	≤ 9.0	Applicable county equation (see attachment)
lbs SO_2/MMBtu, liquid	≤ 3.0	≤ 4.0	≤ 4.6	≤ 5.4	≤ 6.0	
COMPLIANCE PROCEDURES (1-5, listed below)	1d, 2a, 2b, 3c, 4a, 4d, 5b, 5d					

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: specified by the Department
   c. other testing:

Footnotes: See page 5, Kentucky

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A) for existing & new sources with heat input >250 MMBtu/hr
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel, heating value, & ash content
   d. other: For electric generators - average electrical output, minimum & maximum

4. AVERAGING TIME: Hourly generation rate (daily). Summarize both monthly
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: Weekly average for sulfur & ash content & heating value

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 401KAR 50:050 (periodic reports at Director's request)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4 STATE: Kentucky (continued) REGULATION: 401KAR 61:015, Section 5

APPLICABILITY: Area (see attachment, pg. 4)	I	II & III	IV	IVA	V & VA	IVA	V	VA[a]	IVA	V	VA
New/Existing	Existing (constructed on or before 4/9/72)										
FACILITY SIZE (MMBtu/hr)	≥250			≥250 but ≤1,500		>1,500 but <21,000			≥21,000		
FUEL TYPE	Solid fossil Liquid or gaseous fossil			Solid fossil Liquid or gaseous fossil		Solid fossil Liquid or gaseous fossil			Solid fossil Liquid or gaseous fossil		
EMISSIONS LIMIT lbs SO_2/MMBtu, solid lbs SO_2/MMBtu, liquid	≤1.2 ≤0.8	≤3.3 ≤2.2	≤5.2 ≤3.5	≤5.2 ≤3.5	≤6.0 ≤4.0	≤3.5 ≤2.3	≤6.0 ≤4.0	≤1.1 ≤1.1	≤3.1 ≤2.1	≤6.0 ≤4.0	≤1.1 ≤1.1
COMPLIANCE PROCEDURES (1-5, listed below)	1d, 2a, 2b, 3a or 3c, 3d, 4a, 4d, 5b										

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: specified by the Department
   c. other testing:

Footnotes: See page 5, Kentucky

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A) for existing & new sources with heat input >250 MMBtu/hr
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel, heating value, & ash content
   d. other: For electric generators - average electrical output, minimum & maximum

4. AVERAGING TIME: Hourly generation rate (daily). Summarize both monthly
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: Weekly average for sulfur & ash content & heating value

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 401KAR 50:050 (periodic reports at Director's request)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4 STATE: Kentucky (continued) REGULATION: 401KAR 61:015, Section 5

APPLICABILITY: Area New/Existing	Statewide New & Existing	Statewide New (constructed after 4/9/72)	Statewide NSPS, new after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	>10 but ≤250	>250
FUEL TYPE	Combination fossil	Solid, liquid, or gaseous fossil	NSPS, see Appendix A
EMISSIONS LIMIT	Combination fuel equation[a]	Applicable New Source equation (see attachment)	NSPS, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	Applicable size category and county	1d, 2a, 2b, 3c, 3d, 4a, 4d, 5b	1a, 2a, 2b, 3a or 3c, 4a, 4d, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: specified by the Department
   c. other testing:

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A) for existing & new sources with heat input >250 MMBtu/hr
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel, heating value, & ash content
   d. other: For electric generators - average electrical output, minimum & maximum

4. AVERAGING TIME: Hourly generation rate (daily). Summarize both monthly
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: Weekly average for sulfur & ash content & heating value

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 401KAR 50:050 (periodic reports at Director's request)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 5, Kentucky

EPA region: 4 State: Kentucky (continued)

ATTACHMENT

Kentucky

Equations to Determine SO_2 Emissions Limitation (Existing Sources)

County(s)	Class #	Solid Fuel Equation	Liquid or Gaseous Fuel Equation
Jefferson & McCracken	I	$y = 13.9871x^{-0.4434}$	$y = 7.7223x^{-0.4106}$
Muhlenberg	IVA	$y = 13.9871x^{-0.4434}$	$y = 7.7223x^{-0.4106}$
Webster & Hancock	IV	$y = 10.8875x^{-0.1338}$	$y = 7.3639x^{-0.1347}$
Boyd	VA	$y = 10.8875x^{-0.1338}$	$y = 7.3639x^{-0.1347}$
Bell, Clark, & Woodford	II	$y = 11.9134x^{-0.2979}$	$y = 8.01681x^{-0.3047}$
Pulaski	III	$y = 11.9872x^{-0.2236}$	$y = 7.7966x^{-0.2291}$
(all other counties)	V	$y = 12.0284x^{-0.1260}$	$y = 8.0189x^{-0.1260}$

Equations to Determine SO_2 Emissions Limitation (New Sources)

Counties	Solid Fuel Equation	Liquid or Gaseous Fuel Equation
(all counties)	$y = 13.8781x^{-0.4434}$	$y = 7.7223x^{-0.4106}$

where: y = allowable SO_2 emissions (lbs./MMBtu).
x = capacity rating (MMBtu/hr).

EPA region: 4 State: Kentucky (continued)

Footnotes:

[a]All existing and new fuel burning units in county Class VA must limit average annual SO_2 emissions to ≤ 0.6 and hourly emissions to applicable size categories for that county.

[b]Allowable SO_x (lbs/MMBtu) = $\frac{y(a) + z(b)}{y + z}$

where: y = percent of total heat input (liquid or gaseous)
z = percent of total heat input (solid)
a = allowable applicable size category & county SO_2 emissions (lbs. SO_2/MMBtu) for liquid or gaseous fuel
b = allowable applicable size category & county SO_2 emissions (lbs. SO_2/MMBtu) for solid fuel

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4	STATE: Mississippi	REGULATION: APC-S-1

APPLICABILITY:		Statewide		
Area	Statewide			Statewide
New/Existing	Existing (construction on or before 5/8/70)	New indirect heat transfer unit (after 5/8/70)	All modified fuel burning units	NSPS, new after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	All	<250	>250
FUEL TYPE	All fossil	All fossil	All fossil	NSPS, see Appendix A
EMISSIONS LIMIT	≤ average annual emission rate for 1970 units	≤4.8 lb SO_2/MMBtu	≤2.4 lb SO_2/MMBtu	NSPS, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1e, 2c, 3d, 4d, 5b	1a, 2c, 3d, 4d, 5b		1a, 2c, 3a, 4a, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: not specified

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: submit testing data (for permit renewal) to demonstrate compliance at the Commission's request

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: as specified in each permit

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: not specified

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: APC-S-2, Section 4.2 (records of operation and emission data at Commission's request)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:

[a]Modification shall mean any physical change which increases the amount of SO_2 emitted.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4	STATE: North Carolina	REGULATION: Title 15, Chapter 2D, Sections .0500, .0516, .0603, .0604, .0606

APPLICABILITY:				
Area	Statewide	Statewide	Statewide	Statewide
New/Existing	Existing	New (construction after 2/1/76) and not specified in 40 CFR Part 60 or 40 CFR Part 51 with an average annual capacity[a] > 30 percent	NSPS, new after 8/1/71 or 9/18/78	Existing (applicable 40 CFR Part 51 Source
FACILITY SIZE (MMBtu/hr)	All	>250	>250	See Appendix B
FUEL TYPE	All fossil	Coal or residual oil	NSPS, see Appendix A	See Appendix B
EMISSIONS LIMIT lbs SO_2/MMBtu	<2.3 and attain NAAQS[b] for SO_2	≤2.3 and attain NAAQS for SO_2	NSPS, see Appendix A	See Appendix B
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a or 2b, 2c 3c or 3d, 4a[c], 5a	1a, 1c, 2a, 3c, 5b	1a, 2a, 3a, 4a, 5a	

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60
   b. fuel testing: ASTM D3177 (coal of solid) percent sulfur (dry basis)
      ASTM D129 (residual or liquid) % sulfur (dry basis)
      ASTM D129 (distillate or liquid) % sulfur (dry basis)
      other: (coal) sampling-ASTM D2234, preparation-ASTM D2013, Btu-ASTM D2015 (dry basis, moisture-ASTM D3177 (oil) sampling-ASTM D270, Btu-ASTM D240
   c. other testing: Emission rates determined by "F-Factor" Method in 40 CFR 60.45

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: as approved by Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) (arithmetic average of 3 repetitions or runs)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section .0600 (quarterly reports of fuel type, quantity, Btu value, percent sulfur by weight, and total calculated SO_2 emissions.
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 2, North Carolina

EPA region: 4 State: North Carolina (continued)

Footnotes:

[a]Ratio of the average load on equipment for one year.

[b]National Ambient Air Quality Standards.

[c]Determine compliance by stack testing.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4	STATE: South Carolina	REGULATION: No. 1, 62.5

APPLICABILITY: Area / New/Existing	Class I (Charleston County) New & Existing		Class II (Aiken & Anderson Counties) New & Existing		Class III (All other counties) New & Existing
FACILITY SIZE (MMBtu/hr)	≤10	>10	<1,000	≥1,000	All
FUEL TYPE	All fossil	All fossil	All fossil	All fossil	All fossil
EMISSIONS LIMIT lbs SO_2/MMBtu	≤3.5	≤2.3	≤3.5	≤2.3	≤3.5
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4d, 5b, 5d				

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: not specified for SO_2, testing at Director's request

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: not specified for SO_2

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: not applicable

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: not specified for SO_2
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4	STATE: Tennessee	REGULATION: Division of Air Pollution Control Chapter 1200-3-14-.02

APPLICABILITY:												
Area[a]	I		II		III	IV			V	VI	VII	
New/Existing	Existing (construction on or before 4/3/72		Existing (construction on or before 4/3/72		Existing (construction on or before 4/3/72	Existing (construction on or before 4/3/72			Existing (construction on or before 4/3/72	Existing (construction on or before 4/3/72	Existing (construction on or before 4/3/72	
FACILITY SIZE (MMBtu/hr)	>1000	≤1000	>1000	≤1000	All	>600			All	All	>1000	≤1000
FUEL TYPE	All fossil		All fossil		All fossil	coal	#5 & #6 fuel oil	all other fossil	All fossil	All	All	All
EMISSIONS LIMIT lbs SO_2/MMBtu	≤1.2	≤1.6	≤1.2	≤5.0	≤2.4	≤4.0[b]	≤2.7[b]	≤0.5[b]	≤4.0	≤5.0	≤2.8	≤5.0
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a or 2c, 3d, 4d, 5b											

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: specified in operating permit. Stack testing by method contained in Chapter 3, Source Sampling Manual, Tennessee Department of Public Health, 1975 edition

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Technical Secretary in operating permit

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Technical Secretary

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 1200-3-10-.02 (quarterly reports of excesses)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, Tennessee

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 4	STATE: Tennessee (continued)	REGULATION: Division of Air Pollution Control Chapter 1200-3-14-.02

APPLICABILITY:						
Area[a]	I	II, VI, and VII	III	V	Statewide	Statewide
New/Existing	New (construction after 4/3/72	New (construction after 4/3/72	New (construction after 4/3/72	New (construction after 4/3/72	New (construction after 4/3/72	NSPS, after 8/17/71 or 9/18/72 (New)
FACILITY SIZE (MMBtu/hr)	≤250	≤250	≤250	≤250	>250	>250
FUEL TYPE	All fossil	All fossil	All fossil	All fossil	Liquid fossil Solid	NSPS, see Appendix A
EMISSIONS LIMIT lbs SO_2/MMBtu	≤1.6	≤5.0	≤2.4	≤4.0	≤.80 ≤1.2	NSPS, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a or 2c, 3d, 4d, 5b					

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. *other testing:* *specified in operating permit.* Stack testing by method contained in Chapter 3, Source Sampling Manual, Tennessee Department of Public Health, 1975 Edition

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Technical Secretary in operating permit

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Technical Secretary

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 1200-3-10-.02 (quarterly reports of excesses)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, Tennessee

EPA region: 4 State: Tennessee (continued)

Footnotes:

[a] Class I - Polk
Class II - Maury and Humphreys
Class III - Sullivan
Class IV - Shelby
Class V - Anderson, Davidson, Hamilton, Hawkins, Knox, Rhea
Class VI - All counties not specifically classified
Class VII - Roane

[b] Emission limit when using combination fuel:

$$Q_{SO_2} = \frac{4.0x + 2.7y + 0.5z}{x + y + z}$$

where Q_{SO_2} = Allowable Emissions (lbs. SO_2/MMBtu)
x = heat input (coal)
y = heat input (#5 or #6 fuel oil)
z = heat input from all other fuel

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 5	STATE: Illinois	REGULATION: Rule 204

APPLICABILITY: Area[a]	MMA		Statewide	
New/Existing	Existing (construction on or before 8/80		New (construction after 8/80)	
FACILITY SIZE (MMBtu/hr	>250	$\leq$250	All	All
FUEL TYPE	Solid fossil	Solid fossil	Solid fossil	Combination or Solid, Liquid, Gaseous fossil
EMISSIONS LIMIT	$\leq$1.8 lbs SO_2/MMBtu	$\leq$6.8 lbs SO_2/MMBtu	$E = \frac{(H_a)^{0.11}(H_e)^2}{128}$ (lbs SO_2/MMBtu)**	$E = S_sH_s + 0.3\ H_d + S_rH_r$*** (lbs SO_2/MMBtu)
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4b, 5b, 5d			

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: specified by the Agency

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: continuous SO_2 monitoring if requested by the Agency

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Rule 107 (annual reports of emission quantity)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, Illinois

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 5 STATE: Illinois (continued) REGULATION: Rule 204

APPLICABILITY: Area	Statewide					
New/Existing	New (construction after 8/80)					
FACILITY SIZE (MMBtu/hr)	$\leq$250			>250		
FUEL TYPE	Solid fossil	Residual oil	Distillate oil	Solid fossil	Residual oil	Distillate oil
EMISSIONS LIMIT lbs SO_2/MMBtu	$\leq$1.8	$\leq$1.0	$\leq$0.3	$\leq$1.2	$\leq$1.0	$\leq$0.3
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4b, 5b, 5d					

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: specified by the Agency

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: *continuous SO_2 monitoring if requested by the Agency*

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Rule 107 (annual reports of emission quantity)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, Illinois

EPA region: 5 State: Illinois (continued)

Footnotes:

*Refers to fuel combustion sources located in Chicago, St. Louis, and Peoria Metropolitan Areas.

**where: E = allowable SO_2 emissions (lbs./hr.) from all emission sources at one source which is located within a 1 mile radius from the center point of such emission source.

H_a = average actual stack height in feet.

H_e = effective height of effluent release = $H_a + \Delta H$.

ΔH = plume rise.

***where: E = allowable SO_2 emission (lbs./hr.)

S_s = solid fuel standard (lbs./MMBtu)

S_r = residual fuel standard (lbs./MMBtu)

H_s = actual heat input (MMBtu/hr. solid)

H_r = actual heat input (MMBtu/hr. residual)

H_d = actual heat input (MMBtu/hr. distillate)

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 5	STATE: Indiana	REGULATION: Air Pollution Control Board, 325 IAC 7-1, Sections 2, 3, 4

APPLICABILITY: Area New/Existing	Statewide Existing (construction on or before 6/19/79)	Statewide New (construction after 6/19/79)
FACILITY SIZE (MMBtu/hr)	>500 (Includes all sources with potential to emit $\geq$10 lbs SO_2/hr or $\geq$25 tons SO_2/ yr	$\leq$500
FUEL TYPE	All fossil	All fossil
EMISSIONS LIMIT lbs SO_2/MMBtu	$\leq$6.0 and attain NAAQS for SO_2	$\leq$6.0 and attain NAAQS for SO_2
COMPLIANCE PROCEDURES (1-5, listed below)	1c, 2a, 3b, 3c or 3d, 4a, 4b, 5b (1)	1e, 2a, 3c or 3d, 4a, 5b (2)

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: not specified

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing:

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: procedures approved by the Board

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: (1) 325 IAC Section 4 (quarterly reporting of continuous ambient SO_2[a] data to SAROAD[b]) & (2) 325 IAC Section 6 (performance test results and non-compliance procedures)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:

[a]National Ambient Air Quality Standard for SO_2.
[b]Storage and Retrieval or Aerometric Data.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 5	STATE: Michigan	REGULATION: Air Pollution Control General Rule 336.1401, Rule 401, 402

APPLICABILITY:					
Area	Statewide				Statewide
New/Existing	New & Existing				NSPS, new after 8/17/71 or 9/18/78
Compliance Date	1/1/81				N.A.
FACILITY SIZE	≤500,000 lb steam/hr		>500,000 lb steam/hr		>250 MMBtu/hr
FUEL TYPE	Coal	Oil	Coal	Oil	NSPS, see Appendix A
EMISSIONS LIMIT	≤1.5% S or ≤2.4 lbs SO_2/MMBtu	≤1.5% S or ≤1.7 lbs SO_2/MMBtu	≤1.0% S or ≤1.6 lbs SO_2/MMBtu	≤1.0% S or ≤1.1 lbs SO_2/MMBtu	NSPS, see Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2c, 3a , 4a, 4b, 5a, 5b, 5d				1a, 2a, 3a, 4a, 4b, 5a, 5b, 5d

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: specified by the Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour for continuous monitoring data
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Rule 336.202 (annual reports by November 15 of pertinent information to determine compliance
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 2, Michigan

EPA region: 5 State: Michigan (continued)

Footnotes:

[a]Calculated on basis of following fuel heating value: solid: 13,000 Btu/lb; liquid: 18,000 Btu/lb.

[b]Continuous monitoring required if source has unit heat input greater than 250 MMBtu/hr and has pollution abatement device installed.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

Pg. 1

EPA REGION: 5	STATE: Minnesota	REGULATION: APC 4, 6 MCAR §4.004, and APC 32

APPLICABILITY:									
Area	Minneapolis - St. Paul	Statewide				Statewide			
New/Existing	New & Existing	Existing (construction on or before 1/1/80)				New (construction after 1/1/80)			
FACILITY SIZE (MMBtu/hr)	≥100 but <250 per unit, and ≥250 total heat input	≤250 total heat input		>250 total heat input		≤250 total heat input		>250 total heat input	
FUEL TYPE	Liquid fossil	Solid fossil	Liquid fossil	Solid fossil	Liquid fossil	Solid fossil	Liquid fossil	Solid fossil	Liquid fossil
EMISSIONS LIMIT - lbs SO_2/MMBtu	≤1.6	≤4.0	≤2.0	≤3.0	≤1.6	≤4.0	≤2.0	≤1.2	≤0.8
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 1c, 2a or 2c, 3d, 4a, 4b, 5b								

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) N.A. for direct heating equipment
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, see Appendix A
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: Director's approval. If choosing compliance by derating[a], determine actual heat input in Btu/hr. during *each test period*

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: If choosing compliance by derating, continuous monitoring of boiler steam flow

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour (if choosing compliance by derating)
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 6 MCAR §4.004 I (for derating)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, Minnesota

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 5 | STATE: Minnesota (continued) | REGULATION: APC 4, 6 MCAR §4.004 and APC 32

APPLICABILITY:					
Area	Outside Minneapolis - St. Paul		City of Duluth		Statewide
New/Existing	New & Existing		New & Existing		New & Existing
FACILITY SIZE (MMBtu/hr)	>250 total heat input		>250 total		As applicable
FUEL TYPE	Solid fossil	Liquid fossil	Solid fossil	Liquid fossil	Combination fuels
EMISSIONS LIMIT lbs SO_2/MMBtu	≤ 4.0	≤ 2.0	≤ 4.0	≤ 2.0	$w = \frac{y(a) + z(b)}{x + y + z}$
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 1c, 2a or 2c, 3d, 4a, 5b				

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) N.A. for direct heating equipment
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, see Appendix A
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: Director's approval. If choosing compliance by derating[a], determine actual heat input in Btu/hr, during each test period.

Footnotes: See page 3, Minnesota

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: If choosing compliance by derating, continuous monitoring of boiler steam flow

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour (if choosing compliance by derating)
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 6 MCAR §4.004 I (for derating)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

EPA region: 5 State: Minnesota (continued)

Footnotes:

[a] Derating means limitation of heat input and corresponding steam output capacity.

bw = maximum allowable SO_2 emissions (lbs/MMBtu).

x, y, z = percent of total heat input derived from gaseous, liquid, and solid fossil fuels, respectively.

a = applicable SO_2 emissions (lbs/MMBtu) for liquid fossil fuels.

b = applicable SO_2 emissions (lbs/MMBtu) for solid fossil fuels.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 5 STATE: Ohio REGULATION: Rule 3745-18-06 (General Provisions) and Rule 3745-18-07 (Example[a] see attachment)

APPLICABILITY: Area New/Existing	Statewide New after 8/17/71 or 9/18/78	Example: Adam County[a] New & Existing	
FACILITY SIZE (MMBtu/hr)	>250	All	
FUEL TYPE	NSPS, see Appendix A	Coal	All other fossil (source specific[a])
EMISSIONS LIMIT lbs SO_2/MMBtu	NSPS, see Appendix A	≤ 3.6	(Source specific[a])
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 3a, 4a, 4d, 5a, 5d	1b, 2b, 2c, 3a or 3c, 4a, 4d, 5b, 5d	

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60 (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: sulfur & heat content (daily) by EPA methods
   c. other testing: Determine emission rate from fuel sulfur content:

(solid) $ER = \left(\frac{1 \times 10^6}{H}\right)(S)(1.9)$

(liquid) $ER = \left(\frac{1 \times 10^6}{H}\right)(D)(S)(1.974)$

(gaseous) $ER = \left(\frac{1 \times 10^6}{H}\right)(D)(S)(1.998)$

ER = daily actual emission rate
H = heat content in Btu/lb
S = percent sulfur content
D = density of the fuel (lbs/gal)

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 30 day (arithmetic average) of daily compliance averages

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Rule 3745-18-04(G)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 2, Ohio

EPA region: 5 State: Ohio (continued)

Footnotes:

[a]Each county has source specific regulations with no general rules or guidelines. See Rules 3745-18-06 through 3745-18-94 for specific emissions limitations. All sources are allowed 2 days in excess of the (county) emission limitations per 30 day period. Example county used is Adam County.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 5 STATE: Wisconsin REGULATION: NR 154.12

APPLICABILITY: Area[a]	Brokow RACT		Madison RACT				
New/Existing	Construction on or before 1/1/80		Construction on or before 11/1/79				
FACILITY SIZE	All FFFSG[c] with S <160 (S=stack height in ft.)	All other combustion sources with S ≤160 (S= stack height in ft.)	>25 but <100 MMBtu/hr	Utility boiler ≥100 MMBtu/hr	All other boilers ≥100 MMBtu/hr: S <180, 180 ≤ S ≥ 220, S ≥220 (S = stack height(s) in ft.)		
FUEL TYPE	Liquid Fossil	Liquid Fossil	Solid or combination of solid, liquid or gaseous fossil	Solid or combination of solid, liquid or gaseous fossil	Solid or combination of solid, liquid or gaseous fossil		
EMISSIONS LIMIT	≤0.22% S	≤3.0% S	<0.5% S (distillate), ≤1.1% S (residual) or ≤7.0 lb SO_2/MMBtu	<4.25 lb SO_2/MMBtu	<2.5 lb SO_2/MMBtu	X = 10 (0.0089(s)-1.18) (see footnote d)	<5.8 lbs SO_2/MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a or 2c, 3d, 4a or 4d, 5b						

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, see Appendix A
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: specified by the department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified in "ASME Performance Test Code 27", 1957

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: NR 154.06 (annual reports of pertinent information request to determine compliance)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, Wisconsin

Pg. 2

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 5	STATE: Wisconsin (continued)	REGULATION: NR 154.12

APPLICABILITY: Area[a]	Statewide		Southeast Wisconsin Intrastate
New/Existing	New & Existing (construction after 4/1/72)		New & Existing
FACILITY SIZE (MMBtu/hr)	>250		$\leq$250
FUEL TYPE	Solid fossil	Liquid fossil	Coal
EMISSIONS LIMIT lbs SO_2/MMBtu	$\leq$1.2	$\leq$0.8	$\leq$1.1
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a or 2c, 3d, 4a or 4d, 5b		

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, see Appendix A
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: specified by the Department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified in "ASME Performance Test Code 27", 1957

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: NR 154.06 (annual reports of pertinent information request to determine compliance)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, Wisconsin

EPA Region: 5 State: Wisconsin (continued)

Footnotes:

[a]"Air Quality Control Region:

Brokow RACT - Brokow Village and Marathon County
Madison RACT - City of Madison and Dane County

[b]"Reasonably Available Control Technology"

[c]"Fossil Fuel Fired Steam Generator"

[d]Where x = lbs SO_2/MMBtu heat input
s = stack height in ft.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 6	STATE: Arkansas	REGULATION: Air Pollution Control, Section 5 and Section 8

APPLICABILITY: Area New/Existing	Statewide New & Existing	Statewide NSPS, New after 8/17/71 or 9/18/78	Statewide Existing (Applicable 40 CFR 51 Source)
FACILITY SIZE (MMBtu/hr)	All	>250	See Appendix B
FUEL TYPE	All fossil	NSPS, See Appendix A	See Appendix B
EMISSIONS LIMIT	Attain NAAQS*	NSPS, See Appendix A	Attain NAAQS*
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3e, 4a, 5b	1a, 2a, 3a, 4a, 5a, 5b	1a, 2a, 2b or 2c, 3d, 4a, 4d, 5b 5c

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: specified in 40 CFR Part 51 (see Appendix B).
   c. other testing: specified by the Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified in 40 CFR Part 51 (see Appendix B)
   e. as determined necessary by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) for source testing
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified in 40 CFR Part 51 (see Appendix B) for continuous monitoring data

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 7 (biannual reports on 11/30 and 5/31 of each year)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:
*Source must not cause the National Ambient Air Quality Standard for SO_2 to be exceeded; emissions limit specific to individual source operating permit.

SO$_2$ EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 6	STATE: Louisiana	REGULATION: Department of Health and Human Resources Rule 24

APPLICABILITY: Area New/Existing	 Statewide New & Existing	 Statewide NSPS, New after 8/17/71 or 9/18/78	 Statewide Existing Applicable 40 CFR 51 Source
FACILITY SIZE (MMBtu/hr)	All	>250	See Appendix B
FUEL TYPE	All fossil fuels	NSPS, See Appendix A	See Appendix B
EMISSIONS LIMIT	≤2,000 ppm by volume at standard conditions (see footnote a)	NSPS, See Appendix A	See Appendix B
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 2a or 2c, 3d, 4d, 5b	1a, 2a, 3a, 4a, 5a, 5b	1a, 2a, 3a, 4d, 5b, 5c

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr) see footnote b
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: One of the following (see attachment) or approved by the Department

3. MONITORING REQUIREMENTS:
   a. continuous SO$_2$ monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 3 hrs. (arithmetic average)

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Rule 17 (semi-annual reports by 1/20 and 7/20 of all applicable data (emission type, amount, quantity)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 2, Louisiana

EPA Region: 6 State: Louisiana (continued)

2.c. other testing (continued):

1) Seidman, Analytical Chemistry Volume 30, page 1680 (1958) "Determination of Sulfur Oxides in Stack Gases".

2) Shell Development Company method for the Determination of Sulfur Dioxide and Sulfur Trioxide PHS 999 AP-13 Appendix B, pages 85-87 "Atmospheric Emissions Sulfuric Acid Manufacturing Processes".

3) Reich Test for Sulfur Dioxide. "Atmospheric Emissions from Sulfuric Acid Manufacturing Process" PHS 999 AP-13 Appendix B, pages 76-80.

4) The Modified Monsanto Company Method. "Atmospheric Emissions from Sulfuric Acid Manufacturing Process" PHS 999 AP-13, Appendix B, pages 61-67.

Footnotes:

[a]A gas at $21^{\circ}C$ ($70^{\circ}F$) and 29.92 inches of mercury.

[b]Heat input refers to actual measurement determined by the product of heating value of fuel and the quantity of fuel burned in tons/hour.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 6 STATE: New Mexico REGULATION: Air Quality Control Regulation 602 and 605

APPLICABILITY:					
Area	Statewide	Statewide	Statewide	Statewide	Statewide
New/Existing	Existing	Existing	Existing	Existing	Existing
Compliance Date	(on or before 12/31/82)	(on or before 12/31/84)	(on or before 12/31/81)	(after 12/31/81)	(after 12/31/84) if $\geq$2 units/source
FACILITY SIZE (MMBtu/hr)	>250 but $\leq$ 3,000	>250 but $\leq$ 3,000	>3,000 but <5,000	>3,000 but <5,000	>250
FUEL TYPE	Coal	Coal	Coal	Coal	Coal
EMISSIONS LIMIT	emit $\leq$50% of SO_2 produced (footnote a)	emit $\leq$40% of SO_2 produced or $\leq$6,000 lbs SO_2/hr (footnote b)	emit $\leq$40% SO_2 produced (footnote a)	emit $\leq$28% SO_2 produced (footnote a)	emit $\leq$28% SO_2 produced or total SO_2 $\leq$17,900 lbs/hr for source (footnotes a and b)
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2c, 3a, 3c, 4a, 4d, 5a, 5b				

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: performance testing at Director's request, not more than 1 per year (by Method 6).

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: daily average of fuel sulfur content.

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 602 (continuous SO_2 data, rate of actual heat input (daily average), percent sulfur fuel (daily average). Report quarterly)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, New Mexico

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 6	STATE: New Mexico (Continued)	REGULATION: Air Quality Control Regulation 602 and 605

APPLICABILITY: Area	Statewide		Statewide
New/Existing	Compliance for new and existing units on or before 12/31/82		Compliance for new and existing units after 12/31/82
FACILITY SIZE	>25 MW generating capacity or >250 MMBtu/hr		>25 MW generating capacity or >250 MMBtu/hr
	Vintage 1, 2, or 3[c]	Vintage 4[c]	Vintage 1, 2, or 3[c]
FUEL TYPE	Fuel Oil	Fuel Oil	Fuel Oil
EMISSIONS LIMIT lbs SO_2/MMBtu	$\leq$1.2	$\leq$0.34	$\leq$0.55 (30 day average)[d]
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2c, 3a, 3c, 4a, 4c, 5a, 5b		

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: performance testing at Director's request, not more than 1 per year (by Method 6).

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: daily average of fuel sulfur content.

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 602 (continuous SO_2 data, rate of actual heat input (daily average), percent sulfur fuel (daily average). Report quarterly).
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 3, New Mexico

EPA Region: 6 State: New Mexico (continued)

Footnotes:

[a]Averaged over 30 days for all similar sized units (percent reduction basis).

[b]Not to be exceeded more than once per year.

[c]Vintage refers to date beginning commercial operation:

Vintage 1 - began operation between 12/31/76 and 10/31/79.
Vintage 2 - began operation between 11/1/79 and 3/31/82.
Vintage 3 - began operation between 4/1/82 and 12/31/82.
Vintage 4 - other coal burning equipment which is not Vintage 1, 2, or 3.

[d]Refers to a 30 day average of continuous SO_2 monitor hourly data average.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 6	STATE: Oklahoma	REGULATION: 16

APPLICABILITY: Area New/Existing	 Statewide Existing (constructed on or before 6/22/74)	 Statewide New (constructed after 6/22/74)	
FACILITY SIZE (MMBtu/hr)	All	>250	$\leq$250
FUEL TYPE	All fossil	NSPS, See Appendix A	See Appendix A
EMISSIONS LIMIT	Attain NAAQS[a] for SO_2 or source meets New Source emission limits.	NSPS, See Appendix A	See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 3b, 5b or New Source guidelines if >250 MMBtu/hr	1a, 2a, 2b, 3a, 4a, 5a	1a, 2c, 3c, 4c, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, See Appendix A.
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: commissioner's approval
   c. other testing: as specified in 36 FR 159, 8/17/71 (CFR 466.26).

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 13.1 (Existing)
      Not specified (New)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:
[a]Source does not cause or contribute to any SO_2 NAAQS violation.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 6	STATE: Texas	REGULATION: Texas Air Control Board, Regulation II, 131.04

APPLICABILITY: Area (County) New/Existing	Galveston & Harris New & Existing	Jefferson & Orange New & Existing	Statewide New & Existing	Statewide New & Existing	Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	All	All	All	>250
FUEL TYPE	All fossil	All fossil	Solid fossil	Liquid fossil	NSPS, See Appendix A
EMISSIONS LIMIT	Equivalent emissions[a] and ≤0.28 ppm, net ground level concentration	Equivalent emissions[a] and ≤0.32 ppm, net ground level concentration	≤3.0 lbs. SO_2/MMBtu and ≤0.4 ppm, net ground level concentration	≤440 ppm SO_2 by volume and ≤0.4 ppm, net ground level concentration	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 2c, 3d, 4d, 5b				1a, 2a, 3a, 4a, 5a, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)[b]
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, See Appendix A.
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: specified by the Board of the Executive Director or alternate methods on approval. Methods shall be those commonly used in the field of air pollution control.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Board of the Executive Director.

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: not specified.

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: General Rules 31, Ch. 101.8 and Ch. 101.10 (Report test results as specified by the Executive Director).
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes: See page 2, Texas

EPA Region: 6 State: Texas (continued)

Footnotes:

[a]Refers to an emission rate which would not exceed the specified net ground level concentration averaged over a 30 minute period.

[b]Actual heat-input = heating value of fuel X quantity of fuel burned in tons/hour.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 7	STATE: Iowa	REGULATION: IAC Environmental Quality Department 400 Title I

APPLICABILITY:		
Area	Black Hawk, Clinton, Des Moines, Dubuque, Jackson, Lee, Linn, Louisa, Muscatine, Scott counties	
New/Existing	Existing (constructed on or before 9/23/70)	
FACILITY SIZE (MMBtu/hr)	All	All
FUEL TYPE	Solid fossil	Liquid fossil
EMISSIONS LIMIT lbs SO_2/MMBtu	≤ 6.0	≤ 2.5
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2b, 2c, 3d, 4c, 5b	

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR, Pt. 60, (see Appendix A).
   b. fuel testing: ASTM D2015-66 (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: Method 6 as specified in "Compliance Sampling Manual", May 19, 1977. Iowa Environmental Quality Department.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 400-5.1 (455B) Excess emissions reporting and monthly reporting requirements.
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 7	STATE: Iowa	REGULATION: IAC Environmental Quality Department 400 Title I

APPLICABILITY: Area / New/Existing	Statewide Existing (constructed on or before 9/23/70)		Statewide New (constructed after 9/23/70)		Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	>500	All	≤250	All	>250
FUEL TYPE	Solid fossil	Liquid fossil	Solid fossil	Liquid fossil	NSPS, See Appendix A
EMISSIONS LIMIT lbs SO_2/MMBtu	≤5.0	≤2.5	≤6.0	≤2.5	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2b, 2c, 3d, 4c, 5c				1a, 2a, 3a, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR, Pt. 60, (see Appendix A).
   b. fuel testing: ASTMD2015-66coal or solid)
      ASTM ____ (residual or liquid)[a]
      ASTM ____ (distillate or liquid)[a]
      other:
   c. other testing: Method 6 as specified in "Compliance Sampling Manual", May 19, 1977. Iowa Environmental Quality Department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: 400-5.1 (455B) Excess emissions reporting and monthly reporting requirements.
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 7 STATE: Kansas REGULATION: Air Pollution Emission Controls 28-19-31

APPLICABILITY:		
Area	Statewide	Statewide
New/Existing	Existing (construction on or before 1/1/71) Equipment which operates ≥2000 hrs/yr.	New (construction after 1/1/71)
FACILITY SIZE	All	≥250 MMBtu/hr
FUEL TYPE	All fossil (except natural gas)	All fossil
EMISSIONS LIMIT	≤1.5 lbs S/MMBtu (if annual emissions increase by a factor of 2 or more)[a]	≤1.5 lbs S/MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1c, 2b, 2c, 3d, 4d, 5b	

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr) or manufacturer's, whichever is greater
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM D-271-64 (coal or solid) or D-2015-66
      ASTM D-240-64 (residual or liquid)
      ASTM ____ (distillate or liquid)
      other: approved by the Department
   c. other testing: as specified by the Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by the Director

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 28-19-8 (type and amount of fuel burned, emission rate as specified by the Director).
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:

[a]Refers to 1971 emissions or the first 12 months of operation.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 7	STATE: Missouri	REGULATION: Division 10 CSR 10, Chapter 2, Chapter 3, Chapter 4, Chapter 5, Chapter 6.070

APPLICABILITY: Area / New/Existing	Kansas City New and Existing	St. Louis New and Existing (Compliance by 3/24/70)	Springfield - Green County New and Existing	Outstate Missouri Area New and Existing	Statewide New after 8/17/71 or 9/18/78 (NSPS)
FACILITY SIZE	>350,000 Btu/hr.	≥2,000 MMBtu/hr.	>350,000 Btu/hr.	>350,000 Btu/hr.	>250 MMBtu/hr.
FUEL TYPE	All fossil	All fossil	All fossil	All fossil	NSPS, See Appendix A
EMISSIONS LIMIT lbs SO_2/MMBtu	≤9.0	≤4.8	≤9.2	≤12.9	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1d, 2a, 2b, 2c, 3c, 4a, 5b & 5d	1c, 2a, 2b, 2c, 3c, 4a, 4d, 5b & 5d	1d, 2a, 2b, 2c, 3c, 4a, 5b & 5d		1a, 2a, 3a, 4a & 4d, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr) or manufacturers, whichever is greater.
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60.
   b. fuel testing: ASTM D3177-76 (coal or solid) sulfur content
      ASTM D129-64 (residual or liquid) sulfur content
      ASTM D129-64 (distillate or liquid) sulfur content
      other: heat content (solid) by ASTMD (2015-66) & (liquid) by ASTM D(240-64).
   c. other testing:
      specified by the Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) 3 tests (hours), arithmetic average
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 3 hours for continuous SO_2 data as specified in 40 CFR Part 60 (see Appendix A).

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 2.130, 3.130, 4.120, 5.210 (semi-annual reports)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 7	STATE: Nebraska	REGULATION: Air Pollution Control Rule 9 & Rule 4

APPLICABILITY: Area	Statewide	Statewide
New/Existing	New & Existing	NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	>250
FUEL TYPE	All fossil	NSPS, See Appendix A
EMISSIONS LIMIT lbs SO_2/MMBtu	≤ 2.5	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a or 1e, 2a, 2c, 3a, 3d, 4a, 5b, 5d	1a, 2a, 2c, 3a, 4a, 5a, 5d

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) or manufacturer's, whichever
   b. unit actual or operating (MMBtu/hr) is greater.
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: or aggregate heat content of all fuels burned, whichever is greater

2. TEST METHODS:
   a. source testing: Method 6 as specified by 40 CFR Part 60, *see Appendix A.*
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: at Director's request if noncompliance is suspected.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CER Part 60 (see Appendix A)
   b. *1 hour*
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Rule 3 (periodic reports of fuel quantity, emission rate).
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 8	STATE: Colorado	REGULATION: Air Quality Control, Regulation 1, Section A

APPLICABILITY:												
Area	Statewide						Statewide					
New/Existing	Existing (construction on or before 1/30/79)						NSPS, after 8/17/71 or 9/18/78, and other new fuel burning units constructed after 1/30/79					
FACILITY SIZE (MMBtu/hr)	<300	≥300	<300	≥300	<300	≥300	<250	≥250	<250	≥250	<250	≥250
FUEL TYPE	coal		oil		gaseous		coal[a]		oil		gaseous	
EMISSIONS LIMIT lbs SO_2/MMBtu	≤1.8	≤1.2	≤1.5	≤0.8	≤1.2	≤0.8	≤1.2	≤0.4	≤0.8	≤0.3	≤0.8	≤0.35
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2c, 3a, 4a, 4c, 5a											

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: equivalent methods as specified by the Department

Footnotes: See page 2, Colorado

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) for continuous SO_2 data
   b. 1 hour
   c. 2 hours (arithmetic average) for Method 6 or equivalent method
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 8	STATE: Colorado	REGULATION: Air Quality Control, Regulation 1, Section A

APPLICABILITY: Area New/Existing	 Statewide New and Existing
FACILITY SIZE (MMBtu/hr)	 $\geq$250
FUEL TYPE	Combination fossil fuels[b]
EMISSIONS LIMIT lbs SO_2/MMBtu	$PS_{SO_2} = \frac{Y(0.3)+Z(0.4)}{Y+Z}$ (footnote b)
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 2c, 3a, 4a, 4c, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: equivalent methods as specified by the Department

Footnotes: See page 3, Colorado

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) for continuous SO_2 data
   b. 1 hour
   c. 2 hours (arithmetic average) for Method 6 or equivalent method
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:

[a]This includes sources converted from other fuels to coal.

[b]To determine emissions limit: where PS_{SO_2} = prorated emission limit in lbs. SO_2/MMBtu.

Y = percentage of total heat input (liquid).
Z = percentage of total heat input (solid).

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 8	STATE: Montana	REGULATION: Air Quality Rule 16.8.1411

APPLICABILITY: Area New/Existing	Statewide New and Existing (comply after 7/1/72)	Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	>1	>250
FUEL TYPE	solid or liquid fossil	NSPS, See Appendix A
EMISSIONS LIMIT	≤1.0 lbs S/MMBtu	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 2c, 3d, 4d, 5b, 5d	1a, 2a, 3a, 4a, 5a, 5d

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A)
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: as specified by the Director's written request, and new sources should employ Best Available Control Technology (BACT)

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: data specified by Director recorded hourly

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: as specified by the Director

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Rule 16.8.704
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 8	**STATE:** North Dakota	**REGULATION:** Chapter 33-15-06-01

APPLICABILITY:	
Area	Statewide
New/Existing	New & Existing
FACILITY SIZE	All
FUEL TYPE	All fossil
EMISSIONS LIMIT	<3.0 lbs SO_2/MMBtu
COMPLIANCE PROCEDURES (1-5, listed below)	1c, 2a, 3a, 3c, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr) manufacturer's
   d. total plant actual or operating (MMBtu/hr) guaranteed max.
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing:

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Chapter 33-15-12, NSPS General Provisions (where applicable). Annual emission inventory, yearly, judged on case-by-case basis.
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 8	STATE: South Dakota	REGULATION: 44:10:06:03 and 44:10:09:04

APPLICABILITY: Area New/Existing	 Statewide New and Existing	 Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	>250
FUEL TYPE	All fossil	NSPS, See Appendix A
EMISSIONS LIMIT	$\leq$3.0 lbs SO_2/MMBtu	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4a, 5d	1a, 2a, 3a, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) or manufacturer, whichever
   b. unit actual or operating (MMBtu/hr) is greater
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: specified by Director

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: not specified

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 8	STATE: Utah	REGULATION: Air Conservation Regulations (Part IV, Section 4.2)

APPLICABILITY: Area New/Existing	 Statewide New and Existing	 Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All	>250
FUEL TYPE	coal fuel oil	NSPS, See Appendix A
EMISSIONS LIMIT	≤1.0 lbs S/MMBtu ≤0.85 lbs S/MMBtu	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 2a, 2b, 2c, 3d, 4a, 5b	1a, 2a, 2b, 2c, 3a, 4a, 5a, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: applicable ASTM Method
   c. other testing: mandatory every 5 years, source must be at maximum combustion rate during test

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: not specified

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Sections 2.2 and 3.5 (annual emission inventory including emission type, quantity, rate, control equipment used (for sources emitting >25 tons/yr SO_2))
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 8	STATE: Wyoming	REGULATION: Air Quality Regulation Section 4

APPLICABILITY:					
Area	Statewide			Statewide	
New/Existing	Existing (construction on or before 1/1/74)			New (construction after 1/1/74)	
FACILITY SIZE (MMBtu/hr)	>250 but ≤2500	>2500 but ≤5000	>5000	>250	
FUEL TYPE	coal	coal	coal	coal	fuel oil
EMISSIONS LIMIT lbs SO_2/MMBtu	≤1.2	≤0.5	≤0.3	≤0.2	≤0.8
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a or 2c, 3d, 4a, 5b, 5d			1a, 2a, 3a, 4a, 5a	

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr) or manufacturer's, whichever is greater.
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: each stack test by Method 6 or approved equivalent test will consist of 3 separate runs.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Director

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) (arithmetic mean of 3 test runs)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other:

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: section 19 (excesses & equipment malfunction)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 9	STATE: Arizona	REGULATION: Air Pollution Control Commission, Chapter 3, Title 9, R9-3-524

APPLICABILITY: Area	Statewide		Statewide	Statewide
New/Existing	Existing (constructed on or before 5/30/72)		New (constructed after 5/30/72)	NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All		All	>250
FUEL TYPE	Solid or low sulfur oil*	High sulfur oil**	Solid or low sulfur oil*	NSPS, See Appendix A
EMISSIONS LIMIT lbs SO_2/MMBtu	≤ 1.0	≤ 2.2	≤ 0.8	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1c, 1e, 2b, 2c, 3d, 4d, 5b			1c, 1e, 2a or 2c, 3a, 4a, 4d, 5a, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: Aggregate heat content of all fuels whose products of combustion pass through a stack.

2. TEST METHODS:
   a. source testing: Method b as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM D-271 (coal or solid) or ASTM D-2-15
      ASTM ____ (residual or liquid) (heat content)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: Test methods in "Arizona Testing Manual" or other methods as approved by the Department.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A) or state reference method
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: as specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A) (continuous SO_2 data & Method 6)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 3 hr. average and as specified in "Arizona Testing Manual"

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: R9-3-314 (excess emissions) R9-3-308 (periodic reports)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:
*Low sulfur oil is <.90 percent by weight sulfur content.
**High sulfur oil is $\geq$.90 percent by weight sulfur content.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 9	STATE: California	REGULATION: See specific Rule numbers under "Source Applicability" in each APCD.[a]

APPLICABILITY: Area / New/Existing	Bay Area Rule # 9-1-304 New & Existing	Sacramento Rule # 15 New & Existing		San Diego Rule # 62 New & Existing		Fresno Rule # 408 New & Existing	South Coast Rule # 431.2, 116d New & Existing	
FACILITY SIZE (MMBtu/hr)	All	All		All		All	All	
FUEL TYPE	All fossil	Solid & liquid fossil	gaseous	Solid & liquid fossil	gaseous	All fossil	Solid fossil	Liquid fossil
EMISSIONS LIMIT	$\leq$300 ppm or $\leq$0.5% S	$\leq$0.5% S	$\leq$50 gr/100 cu. ft. fuel input	$\leq$0.5% S	$\leq$10 gr/100 cu. ft. fuel input	$\leq$200 lbs SO_2/hr	$\leq$0.56 lb SO_2/MMBtu	<0.5% S
COMPLIANCE PROCEDURES (1-5, listed below)	1e, 2c, 3d, 4d, 5e							

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: specified by applicable APCD

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: specified by applicable APCD method

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by applicable APCD requirements

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by applicable APCD requirements

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director
   e. specified by applicable APCD requirements

Footnotes: See page 3, California

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 9	STATE: California	REGULATION: See specific Rule numbers under "Source Applicability" in each APCD.[a]

APPLICABILITY:	
Area	Statewide
New/Existing	NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE	>250 MMBtu/hr
FUEL TYPE	NSPS, See Appendix A
EMISSIONS LIMIT	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2a, 3a, 4a, 5a

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: specified by applicable APCD

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: specified by applicable APCD method

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by applicable APCD requirements

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified by applicable APCD requirements

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation:
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director
   e. specified by applicable APCD requirements

Footnotes: See page 3, California

EPA Region: 9 State: California (continued)

Footnotes:

[a]Refers to Air Pollution Control Districts. There are 15 APCD's in California and each applicable district's regulations should be consulted to determine specific test methods, averaging times, and reporting requirements. Emission limitations are expressed for individual counties in each district. Typical APCD regulations limit SO_2 emissions and fuel sulfur contents to 200 lbs./hr. and 0.5% sulfur by weight, respectively. The districts specifically mentioned are examples.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 9	STATE: Hawaii	REGULATION: Chapter 43, Vol. II, Section 14

APPLICABILITY: Area	Statewide
New/Existing	New and Existing
FACILITY SIZE (MMBtu/hr)	All
FUEL TYPE	All fossil
EMISSIONS LIMIT	$\leq$2.0% S
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4d, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: as specified by the Department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: not specified

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 3, 4 and Section 342-22 (as specified by the Department).
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS (SIP Regulations)

EPA REGION: 9	STATE: Nevada	REGULATION: Air Quality Regulation, Article 8

APPLICABILITY: Area New/Existing	Statewide New and Existing (excluding applicable 40 CFR 51 sources)		Statewide New and Existing Applicable 40 CFR 51, Appendix B Sources
FACILITY SIZE	<250 Btu/hr.	$\geq$250 Btu/hr.	See Appendix B
FUEL TYPE	All fossil	All fossil (or combination)	See Appendix B
EMISSIONS LIMIT	Y = 0.7 x (lbs. S/MMBtu) see footnote a	$Y = \frac{L(0.4) + S(0.6)}{L + S}$ (lbs. S/MMBtu) see footnote a	See Appendix B (lbs. SO_2/MMBtu)
COMPLIANCE PROCEDURES (1-5, listed below)	1b, 2c, 5b, 5c, 5d		1a, 2c, 3a, 4a, 5b, 5c, 5d

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing:
   b. fuel testing: ASTM ____ (coal or solid)
      ASTM ____ (residual or liquid)
      ASTM ____ (distillate or liquid)
      other:
   c. other testing: testing specified by the Director prior to permit issuance or renewal. Recognized methods will be used and two separate runs of the test procedure are required

Footnotes: See page 2, Nevada

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: continuous SO_2 monitoring by 40 CFR Part 51 (see Appendix B)

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: specified in 40 CFR Part 51 (see Appendix B)

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section 2.6-2.17 (excess emissions)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

EPA Region: 9 State: Nevada (continued)

<u>Footnotes</u>:

[a]where X = operating heat input in MMBtu/hr.
Y = allowable rate of five emissions in lbs/hr.
L = percentage of total heat input (liquid fuel).
S = percentage of total heat input (solid fuel).

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 10	STATE: Alaska	REGULATION: Title 18, Chapter 50, Article 1.050

APPLICABILITY:	
Area	Statewide
New/Existing	New and Existing
FACILITY SIZE (MMBtu/hr)	All
FUEL TYPE	All fossil
EMISSIONS LIMIT	$\leq$500 ppm SO_2 by volume, dry basis determination
COMPLIANCE PROCEDURES (1-5, listed below)	1a[a] or 1b[a], 2a, 2b, 3d, 4d, 5b, 5d

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: *Method 6 as specified in 40 CFR Part 60, (see Appendix A) with unit at maximum capacity.*
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other: sulfur, ash, moisture content
   c. other testing:

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate if sulfur content 0.7 percent
   c. sulfur content of fuel
   d. other: specified in permit

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: 3 hour average

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Section IV.H.1.d
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:
[a]Specified in permit to operate.

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 10	STATE: Idaho	REGULATION: Air Pollution Control Title 1, Ch. 1, Rule 1351 through 1355

APPLICABILITY: Area New/Existing	Statewide New and Existing				Statewide NSPS, New after 8/17/71 or 9/18/78
FACILITY SIZE (MMBtu/hr)	All				>250
FUEL TYPE	Coal	Residual fuel oil	Distillate fuel oil ASTM grade 1	Distillate fuel oil ASTM grade 2	NSPS, See Appendix A
EMISSIONS LIMIT	$\leq$1.0% S	$\leq$1.75% S	$\leq$0.3% S	$\leq$0.5% S	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1e, 2b, 2c, 3c, 4d, 5b				1a, 2b, 3a or 3c, 4a or 4d, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: *not specified for compliance purposes*

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM D271-68 (coal or solid)
      ASTM D1551-68 (residual or liquid) or D129-64 or D1552-64
      ASTM D1551-68 (distillate or liquid) or D129-64 or D1552-64
      other: heating value and ash content once per week
   c. other testing: Test procedures in "Procedures Manual for Air Pollution Control", Idaho Department of Health and Welfare.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: Daily for fuel analysis, other specified by the Director

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Rule 1005 (periodic reports) and Rule 1954 (monthly summary of estimated SO_2 emissions)
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 10	STATE: Oregon	REGULATION: Chapter 340, Division 22

APPLICABILITY:							
Area	Statewide		Statewide		Statewide		Statewide
New/Existing	New & Existing Must comply by 1/1/72		New & Existing After 1/1/74		New Must comply by 1/1/72		NSPS, New construction
Other	uncontrolled[a]		uncontrolled[a]		N.A.		N.A.
FACILITY SIZE (MMBtu/hr)	All		All		>150 but $\leq$250		>250
FUEL TYPE	Distillate (ASTM Grade) 1	2	coal	residual	solid	liquid	NSPS, See Appendix A
EMISSIONS LIMIT	$\leq$0.3% S	$\leq$0.5% S	$\leq$1.0% S	$\leq$1.75% S	1.4 lbs. SO_2/MMBtu (footnote b)	1.6 lbs. SO_2/MMBtu (footnote b)	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1a, 2c, 3d, 4d, 5b				1a, 2c, 3b, 3d, 4c, 5b		1a, 2c, 3d, 3b, 4c, 5b

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other:

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: any method accepted by the Department

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other: specified by the Department

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average) during emission test
   d. other: not specified

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: Division 20 (semi-annual basis and test results as requested by the Director
   c. specified in 40 CFR Part 51 (see Appendix B)
   d. specified by the Director

Footnotes:

[a] Refers to a source using no SO_2 pollution abatement devices. Controlled sources may use higher sulfur content coal if equivalent emission rate to sulfur restrictions can be achieved on approval by the Department.

[b] Refers to maximum emission rate for 2 hour average (using actual heat input for testing).

SO_2 EMISSION LIMITATIONS FROM FUEL BURNING INSTALLATIONS
(SIP Regulations)

EPA REGION: 10 STATE: Washington REGULATION: WAS 173-400-040

APPLICABILITY: Area	Statewide	Statewide
New/Existing	New and Existing fuel burning units (includes Wigwam and hog fuel boilers also)	New after 8/17/71 or 9/18/78 NSPS
FACILITY SIZE (MMBtu/hr)	All	>250
FUEL TYPE	All fossil fuels and wood waste	NSPS, See Appendix A
EMISSIONS LIMIT	$\leq$1,000 ppm*	NSPS, See Appendix A
COMPLIANCE PROCEDURES (1-5, listed below)	1e, 2c, 3b, 4d, 5b	1a, 2a, 3a, 3b, 4a, 5b, 5c

1. HEAT INPUT DETERMINATION:
   a. unit design rated (MMBtu/hr)
   b. unit actual or operating (MMBtu/hr)
   c. total plant design rated (MMBtu/hr)
   d. total plant actual or operating (MMBtu/hr)
   e. other: not specified

2. TEST METHODS:
   a. source testing: Method 6 as specified in 40 CFR Part 60, (see Appendix A).
   b. fuel testing: ASTM _____ (coal or solid)
      ASTM _____ (residual or liquid)
      ASTM _____ (distillate or liquid)
      other:
   c. other testing: source testing at the request of the Director by procedures contained in "Source Test Manual - Procedures for Compliance Testing", State of Washington, Department of Ecology.

3. MONITORING REQUIREMENTS:
   a. continuous SO_2 monitoring by 40 CFR Part 60 (see Appendix A)
   b. ambient monitoring or diffusion estimate
   c. sulfur content of fuel
   d. other:

4. AVERAGING TIME:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. 1 hour
   c. 2 hours (arithmetic average)
   d. other: not specified

5. REPORTING:
   a. specified in 40 CFR Part 60 (see Appendix A)
   b. state regulation: WAC 173-400-120 (annual emission inventory with estimated quarterly emissions.
   c. specified in 40 CFR Part 51 (see Appendix B) for SO_2 continuous monitoring equipment
   d. specified by the Director

Footnotes:
*Exhaust gas volume is corrected to 7 percent oxygen.

References

1. Sargent, D.H., et al. Effect of Physical Coal Cleaning on Sulfur Content and Variability, Versar, Inc., Springfield, VA, EPA 600/7-80-107, May 1980, pg. 66.

2. "Compilation of Air Pollution Emission Factors," Supplement No. 6, Environmental Protection Agency, AP-42, April 1976, P. 1.1-3.

3. "Steam/Its Generation and Use," Babcock and Wilcox, New York, NY, 1975, P. 5-11 and 5-19.

Appendix A. Federal New Source Performance Standard Criteria

Sources subject to Federal fuel combustion source sulfur dioxide (SO_2) regulations follow the guidelines contained in 40CFR60, July 1979. The applicable emission limitations, testing and reporting proceedures are reproduced for your convenience from Subpart D, Subpart Da, and Appendix A (Reference Method 6 – Determination of SO_2 Emissions From Stationary Sources).

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu per hour).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§ 60.44(a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility covered under Subpart Da is not covered under this Subpart.

(Secs. 111, 114, and 301(a), Clean Air Act; Sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a), 7411, 7414, and 7601))

[42 FR 37936, July 25, 1977, as amended at 43 FR 9278, Mar. 7, 1978; 44 FR 33612, June 17, 1979]

§ 60.41 Definitions.

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

(a) "Fossil-fuel fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

(b) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(c) "Coal refuse" means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

(d) "Fossil fuel and wood residue-fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

(e) "Wood residue" means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

(f) "Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing Material. Designation D 388-66.

(Secs. 111 and 301(a), Clean air Act, as amended (42 U.S.C. 7411, 7414, and 7601))

[39 FR 20791, June 14, 1974, as amended at 40 FR 2803, Jan. 16, 1975; 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978]

§ 60.42 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is 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 which:

(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(Sec. 111, 301(a), Clean Air Act as amended (42 U.S.C. 7411, 7601))

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 42 FR 61537, Dec. 5, 1977]

§ 60.43 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is 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 which contain sulfur dioxide in excess of:

(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue.

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{so_2} = [y(340) + z(520)]/y + z$$

where:

PS_{so_2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976]

§ 60.44 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is 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 which contain nitrogen oxides, expressed as NO_2 in excess of:

(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel or gaseous fossil fuel and wood residue.

(2) 130 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(3) 300 nanograms per joule heat input (0.70 lb per million Btu) 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 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 nanograms per joule heat input (0.80 lb per million Btu) 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) and (d) 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_{NO_x} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = is the percentage of total heat input derived from lignite;

x = is the percentage of total heat input derived from gaseious fossil fuel;

y = is the percentage of total heat input derived from liquid fossil fuel; and

z = is the 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 nitrogen oxides does not apply.

(d) 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.

(Secs. 111 and 301(a) of the Clean Air Act, as amended (42 U.S.C. 7411, and 7601))

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978]

§ 60.45 Emission and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(b) Certain of the continuous monitoring system 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, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under paragraph (d) of this section.

(3) Notwithstanding § 60.13(b), installation of a continuous monitoring system for nitrogen oxides 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 nitrogen oxides are less than 70 percent of the applicable standards in § 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides 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 continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

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

(1) Reference Methods 6 or 7, as applicable, shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance 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 and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	(1)	500
Liquid	1,000	500
Solid	1,500	500
Combinations	$1,000y+1,500z$	$500(x+y)+1,000z$

[1]Not applicable.

where:

x=the fraction of total heat input derived from gaseous fossil fuel, and

y=the fraction of total heat input derived from liquid fossil fuel, and

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

(4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.

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

(d) [Reserved]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen 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:

$$E = CF[20.9/20.9\text{—percent } O_2]$$

where:

E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c[100/\text{percent } CO_2]$$

where:

E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(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/million Btu).

(2) C=pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M=pollutant molecular weight, g/g-mole (lb/lb-mole). M=64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

(3) $\%O_2$, $\%CO_2$=oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (d) 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 carbon dioxide 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 A.S.T.M. D 388-66, $F=2.723\times10^{-17}$ dscm/J (10,140 dscf/million Btu) and $F_c=0.532\times10^{-17}$ scm CO_2/J (1,980 scf CO_2/million Btu).

(ii) For subbituminous and bituminous coal as classified according to A.S.T.M. D 388-66, $F=2.637\times10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c=0.486\times10^{-7}$ scm CO_2/J (1,810 scf CO_2/million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F=2.476\times10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c=0.384\times10^{-7}$ scm CO_2/J (1,430 scf CO_2/million Btu).

(iv) For gaseous fossil fuels, $F=2.347\times10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c=0.279\times10^{-7}$ scm CO_2/J (1,040 scf CO_2/million Btu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/million Btu) for butane.

(v) For bark $F=2.589\times10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c=0.500\times10^{-7}$ scm CO_2/J (1,840 scf CO_2/ million Btu). For wood residue other than bark $F=2.492\times10^{-7}$ dscm/J (9,280 dscf/million Btu) and $F_c=0.494\times10^{-7}$ scm CO_2/J (1,860 scf CO_2/ million Btu).

(vi) For lignite coal as classified according to A.S.T.M. D 388-66, $F=2.659\times10^{-7}$ dscm/J (9900 dscf/million Btu) and $F_c=0.516\times10^{-7}$ scm CO_2/J (1920 scf CO_2/million Btu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2/J, or scf CO_2/million Btu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

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

$$F_c = \frac{2.0 \times 10^{-5}\ (\text{pct. C})}{\text{GCV}}.$$

(SI units)

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

(English units)

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

(SI units)

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

(English units)

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using A.S.T.M. method D3178-74 or D3176 (solid fuels), or computed from results using A.S.T.M. methods D1137-53(70), D1945-64(73), or D1946-67(72) (gaseous fuels) as applicable.

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted, determined by the A.S.T.M. test methods D2015-66(72) for solid fuels and D 1826-64(70) for gaseous fuels as applicable.

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c 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_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

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

where:

X_i=the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or $(F_c)_i$=the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n=the number of fuels being burned in combination.

(g) For the purpose of reports required under § 60.7(c), periods of excess emissions 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.

(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 sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under § 60.43.

(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44.

(Secs. 111, 114, and 301(a), Clean Air Act, as amended (42 U.S.C. 7411, 7414, and 7601))

[40 FR 46256, Oct. 6, 1975; 40 FR 59205, Dec. 22, 1975, as amended at 41 FR 51399, Nov. 22, 1976; 42 FR 5936, Jan. 31, 1977; 42 FR 41122, Aug. 15, 1977; 42 FR 61537, Dec. 5, 1977; 43 FR 8800, Mar. 3, 1978; 43 FR 9278, Mar. 7, 1978]

§ 60.46 Test methods and procedures.

(a) The reference methods in Appendix A of this part, except as provided in § 60.8(b), shall be used to determine compliance with the standards as prescribed in §§ 60.42, 60.43, and 60.44 as follows:

(1) Method 1 for selection of sampling site and sample traverses.

(2) Method 3 for gas analysis to be used when applying Reference Methods 5, 6 and 7.

(3) Method 5 for concentration of particulate matter and the associated moisture content.

(4) Method 6 for concentration of SO_2, and

(5) Method 7 for concentration of NO_x.

(b) For Method 5, 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 60 minutes and the minimum sampling volume shall be 0.85 dscm (30 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The probe and filter holder heating systems in the sampling train shall be set to provide a gas temperature no greater than 433 K (320°F).

(c) For Methods 6 and 7, the sampling site shall be the same as that selected for Method 5. The sampling point in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). For Method 6, the sample shall be extracted at a rate proportional to the gas velocity at the sampling point.

(d) For Method 6, the minimum sampling time shall be 20 minutes and the minimum sampling volume 0.02 dscm (0.71 dscf) for each sample. The arithmetic mean of two samples shall constitute one run. Samples shall be taken at approximately 30-minute intervals.

(e) For Method 7, each run shall consist of at least four grab samples taken at approximately 15-minute intervals. The arithmetic mean of the samples shall constitute the run value.

(f) For each run using the methods specified by paragraphs (a)(3), (a)(4), and (a)(5) of this section, the emissions expressed in ng/J (lb/million Btu) shall be determined by the following procedure:

$$E = CF(20.9/20.9 - \text{percent } O_2)$$

where:

(1) E=pollutant emission ng/J (lb/million Btu).

(2) C=pollutant concentration, ng/dscm (lb/dscf), determined by method 5, 6, or 7.

(3) Percent O_2=oxygen content by volume (expressed as percent), dry basis. Percent oxygen shall be determined by using the integrated or grab sampling and analysis procedures of Method 3 as applicable.

The sample shall be obtained as follows:

(i) For determination of sulfur dioxide and nitrogen oxides emissions, the oxygen sample shall be obtained simultaneously at the same point in the duct as used to obtain the samples for Methods 6 and 7 determinations, respectively [§ 60.46(c)]. For Method 7, the oxygen sample shall be obtained using the grab sampling and analysis procedures of Method 3.

(ii) For determination of particulate emissions, the oxygen sample shall be obtained simultaneously by traversing the duct at the same sampling location used for each run of Method 5 under paragraph (b) of this section. Method 1 shall be used for selection of the number of traverse points except that no more than 12 sample points are required.

(4) F=a factor as determined in paragraphs (f) (4), (5) or (6) of § 60.45.

(g) When combinations of fossil fuels or fossil fuel and wood residue are fired, the heat input, expressed in watts (Btu/hr), is determined during each testing period by multiplying the gross calorific value of each fuel fired (in J/kg or Btu/lb) by the rate of each fuel burned (in kg/sec or lb/hr). Gross calorific values are determined in accordance with A.S.T.M. methods D

2015-66(72) (solid fuels), D 240-64(73) (liquid fuels), or D 1826-64(7) (gaseous fuels) as applicable. The method used to determine calorific value of wood residue must be approved by the Administrator. The owner or operator shall determine the rate of fuels burned during each testing period by suitable methods and shall confirm the rate by a material balance over the steam generation system.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

[40 FR 46258, Oct. 6, 1975, as amended at 41 FR 53199, Nov. 22, 1976; 43 FR 8800, Mar. 3, 1978]

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

AUTHORITY: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

SOURCE: 44 FR 33613, June 11, 1979, unless otherwise noted.

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to Subpart GG.)

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41a Definitions.

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

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Subbituminous coal" means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

"Lignite" means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

"Coal refuse" means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

"Potential combustion concentration" means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state 9without emission control systems) and:

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 75 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under § 60.48a(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

"Combined cycle gas turbine" means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

"Interconnected" means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

"Electric utility company" means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

"Principal company" means the electric utility company or companies which own the affected facility.

"Neighboring company" means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

"Net system capacity" means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"System load" means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

"System emergency reserves" means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"Available system capacity" means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

"Spinning reserve" means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"Available purchase power" means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

"Spare flue gas desulfurization system module" means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

"Emergency condition" means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Anthracite" means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

"Solid-derived fuel" means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.

"24-hour period" means the period of time between 12:01 a.m. and 12:00 midnight.

"Resource recovery unit" means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

"Noncontinental area" means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

"Boiler operating day" means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours.

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is 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 which contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under § 60.8 is 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 which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.43a Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases which contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section), any gases which contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be conducted under § 60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC-I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery facility, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dixoide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$E_{SO_2} = [340\ x + 520\ y]/100$ and
$P_{SO_2} = 10$ percent

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$E_{SO_2} = [340\ x + 520\ y]/100$ and
$P_{SO_2} = [90\ x + 70\ y]/100$

where:

E_{SO_2} is the prorated sulfur dioxide emission limit (ng/J heat input),

P_{SO_2} is the percentage of potential sulfur dioxide emission allowed (percent reduction required $= 100 - PS_{SO_2}$).

x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)

y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

§ 60.44a Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraph (b) of this section, any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

(1) NO_x Emission Limits—

Fuel type	Emission limit ng/J (lb/million Btu) heat input	
Gaseous Fuels:		
Coal-derived fuels	210	(0.50)
All other fuels	86	(0.20)
Liquid Fuels:		
Coal-derived fuels	210	(0.50)
Shale oil	210	(0.50)
All other fuels	130	(0.30)
Solid Fuels:		
Coal-derived fuels	210	(0.50)
Any fuel containing more than 25%, by weight, coal refuse	Exempt from NO_x standards and NO_x monitoring requirements	
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace	340	(0.80)
Lignite not subject to the 340 ng/J heat input emission limit	260	(0.60)
Subbituminous coal	210	(0.50)
Bituminous coal	260	(0.60)
Anthracite coal	260	(0.60)
All other fuels	260	(0.60)

(2) NO_x reduction requirements—

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25%
Liquid fuels	30%
Solid fuels	65%

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(c) When two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$E_{NO_x} = [86\ w + 130\ x + 210\ y + 260\ z]/100$

where:

E_{NO_x} is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard; and

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard.

§ 60.45a Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(c) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_x emission limitation and percent reduction under § 60.44a(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC I)	SO_2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	400–1,200
Coal liquification	NO_x	750–10,000
Total allowable for all technologies		15,000

§ 60.46a Compliance provisions.

(a) Compliance with the particulate matter emission limitation under § 60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under § 60.42a(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under § 60.44a(a) constitutes compliance with the percent reduction requirements under § 60.44a(a)(2).

(c) The particulate matter emission standards under § 60.42a and the nitrogen oxides emission standards under § 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and

bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (i) under § 60.43a for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under § 60.43a and the nitrogen oxides emission limitations under § 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under § 60.43a and the nitrogen oxides emission limitation under § 60.44a is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.47a of this subpart, compliance of the affected facility with the emission requirements under §§ 60.43a and 60.44a of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in sections 6.0 and 7.0 of Reference Method 19 (Appendix A).

§ 60.47a Emission monitoring.

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility which qualifies under the provisions of § 60.43a(d), sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 (Appendix A) may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) When emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using other monitoring systems as approved by the Administrator or the reference methods as described in paragraph (h) of this section to provide emission data for a minimum of 18 hours in at least 22 out of 30 successive boiler operating days.

(g) The 1-hour averages required under paragraph § 60.13(h) are expressed in ng/J (lbs/million Btu) heat input and used to calculate the average emission rates under § 60.46a. The 1-hour averages are calculated using the data points required under § 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) Reference methods used to supplement continuous monitoring system data to meet the minimum data requirements in paragraph § 60.47a(f) will be used as specified below or otherwise approved by the Administrator.

(1) Reference Methods 3, 6, and 7, as applicable, are used. The sampling location(s) are the same as those used for the continuous monitoring system.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average.

(3) For Method 7, samples are taken at approximately 30-minute intervals. The arithmetic average of these two consective samples represent a 1-hour average.

(4) For Method 3, the oxygen or carbon dioxide sample is to be taken for each hour when continuous SO_2 and NO_x data are taken or when Methods 6 and 7 are required. Each sample shall be taken for a minimum of 30 minutes in each hour using the integrated bag method specified in

Method 3. Each sample represents a 1-hour average.

(5) For each 1-hour average, the emissions expressed in ng/J (lb/million Btu) heat input are determined and used as needed to achieve the minimum data requirements of paragraph (f) of this section.

(i) The following procedures are used to conduct monitoring system performance evaluations under § 60.13(c) and calibration checks under § 60.13(d).

(1) Reference method 6 or 7, as applicable, is used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.

(2) Sulfur dioxide or nitrogen oxides, as applicable, is used for preparing calibration gas mixtures under performance specification 2 of appendix B to this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid	1,000
Combination	500 (x+y)+1,000z

where:
x is the fraction of total heat input derived from gaseous fossil fuel,
y is the fraction of total heat input derived from liquid fossil fuel, and
z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.48a Compliance determination procedures and methods.

(a) The following procedures and reference methods are used to determine compliance with the standards for particulate matter under § 60.42a.

(1) Method 3 is used for gas analysis when applying method 5 or method 17.

(2) Method 5 is used for determining particulate matter emissions and associated moisture content. Method 17 may be used for stack gas temperatures less than 160 C (320 F).

(3) For Methods 5 or 17, Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(4) For Method 5, the probe and filter holder heating system in the sampling train is set to provide a gas temperature no greater than 160°C (32°F).

(5) For determination of particulate emissions, the oxygen or carbon-dioxide sample is obtained simultaneously with each run of Methods 5 or 17 by traversing the duct at the same sampling location. Method 1 is used for selection of the number of traverse points except that no more than 12 sample points are required.

(6) For each run using Methods 5 or 17, the emission rate expressed in ng/J heat input is determined using the oxygen or carbon-dioxide measurements and particulate matter measurements obtained under this section, the dry basis F_c-factor and the dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Prior to the Administrator's issuance of a particulate matter reference method that does not experience sulfuric acid mist interference problems, particulate matter emissions may be

sampled prior to a wet flue gas desulfurization system.

(b) The following procedures and methods are used to determine compliance with the sulfur dioxide standards under § 60.43a.

(1) Determine the percent of potential combustion concentration (percent PCC) emitted to the atmosphere as follows:

(i) *Fuel Pretreatment* (% R_f): Determine the percent reduction achieved by any fuel pretreatment using the procedures in Method 19 (Appendix A). Calculate the average percent reduction for fuel pretreatment on a quarterly basis using fuel analysis data. The determination of percent R_f to calculate the percent of potential combustion concentration emitted to the atmosphere is optional. For purposes of determining compliance with any percent reduction requirements under § 60.43a, any reduction in potential SO_2 emissions resulting from the following processes may be credited:

(A) Fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.),

(B) Coal pulverizers, and

(C) Bottom and flyash interactions.

(ii) *Sulfur Dioxide Control System* (% R_g): Determine the percent sulfur dioxide reduction achieved by any sulfur dioxide control system using emission rates measured before and after the control system, following the procedures in Method 19 (Appendix A); or, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19 (Appendix A). When the "as fired" fuel monitor is used, the percent reduction is calculated using the average emission rate from the sulfur dioxide control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(iii) *Overall percent reduction* (% R_o): Determine the overall percent reduction using the results obtained in paragraphs (b)(1) (i) and (ii) of this section following the procedures in Method 19 (Appendix A). Results are calculated for each 30-day period using the quarterly average percent sulfur reduction determined for fuel pretreatment from the previous quarter and the sulfur dioxide reduction achieved by a sulfur dioxide control system for each 30-day period in the current quarter.

(iv) *Percent emitted* (% *PCC*): Calculate the percent of potential combustion concentration emitted to the atmosphere using the following equation: Percent PCC = 100 − Percent R_o

(2) Determine the sulfur dioxide emission rates following the procedures in Method 19 (Appendix A).

(c) The procedures and methods outlined in Method 19 (Appendix A) are used in conjunction with the 30-day nitrogen-oxides emission data collected under § 60.47a to determine compliance with the applicable nitrogen oxides standard under § 60.44.

(d) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19 (Appendix A). The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 (Appendix A) calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive

boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

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

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by § 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of § 60.46a(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate (E_o^*) and the upper confidence limit for the mean inlet emission rate (E_i^*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate (E_o^*) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under § 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under § 60.46a(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under § 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of § 60.48a and Method 19 (Appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(h) For the purposes of the reports required under § 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under § 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(i) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

Subpart E—Standards of Performance for Incinerators

§ 60.50 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each incinerator of more than 45 metric tons per day charging rate (50 tons/day), which is the affected facility.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(Secs. 111 and 301(a), Clean Air Act; sec. 4a) of Pub. L. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a)))

[42 FR 37936, July 25, 1977]

§ 60.51 Definitions.

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

(a) "Incinerator" means any furnace used in the process of burning solid waste for the purpose of reducing the volume of the waste by removing combustible matter.

(b) "Solid waste" means refuse, more than 50 percent of which is municipal type waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustibles, and noncombustible materials such as glass and rock.

(c) "Day" means 24 hours.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 20792, June 14, 1974]

§ 60.52 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent CO_2.

[39 FR 20792, June 14, 1974]

§ 60.53 Monitoring of operations.

(a) The owner or operator of any incinerator subject to the provisions of this part shall record the daily charging rates and hours of operation.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

[39 FR 20792, June 14, 1974, as amended at 43 FR 8800, Mar. 3, 1978]

§ 60.54 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standard prescribed in § 60.52 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis and calculation of excess air, using the integrated sample technique.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30.0 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) If a wet scrubber is used, the gas analysis sample shall reflect flue gas conditions after the scrubber, allowing for carbon dioxide absorption by sampling the gas on the scrubber inlet and outlet sides according to either the procedure under paragraphs (c)(1) through (c)(5) of this section or the procedure under paragraphs (c)(1), (c)(2) and (c)(6) of this section as follows:

(1) The outlet sampling site shall be the same as for the particulate matter measurement. The inlet site shall be selected according to Method 1, or as specified by the Administrator.

(2) Randomly select 9 sampling points within the cross-section at both the inlet and outlet sampling sites. Use the first set of three for the first run, the second set for the second run, and the third set for the third run.

(3) Simultaneously with each particulate matter run, extract and analyze for CO_2 an integrated gas sample according to Method 3, traversing the three sample points and sampling at each point for equal increments of time. Conduct the runs at both inlet and outlet sampling sites.

(4) Measure the volumetric flow rate at the inlet during each particulate matter run according to Method 2, using the full number of traverse points. For the inlet make two full velocity traverses approximately one hour apart during each run and average the results. The outlet volumetric flow rate may be determined from the particulate matter run (Method 5).

(5) Calculate the adjusted CO_2 percentage using the following equation:

$$(\% CO_2)_{adj} = (\% CO_2)_{di} (Q_{di}/Q_{do})$$

where:

$(\% CO_2)_{adj}$ is the adjusted CO_2 percentage which removes the effect of CO_2 absorption and dilution air,

$(\% CO_2)_{di}$ is the percentage of CO_2 measured before the scrubber, dry basis,

Q_{di} is the volumetric flow rate before the scrubber, average of two runs, dscf/min (using Method 2), and

Q_{do} is the volumetric flow rate after the scrubber, dscf/min (using Methods 2 and 5).

(6) Alternatively, the following procedures may be substituted for the procedures under paragraphs (c) (3), (4), and (5) of this section:

(i) Simultaneously with each particulate matter run, extract and analyze for CO_2, O_2, and N_2 an integrated gas sample according to Method 3, traversing the three sample points and sampling for equal increments of time at each point. Conduct the runs at both the inlet and outlet sampling sites.

(ii) After completing the analysis of the gas sample, calculate the percentage of excess air (% EA) for both the inlet and outlet sampling sites using equation 3-1 in Appendix A to this part.

(iii) Calculate the adjusted CO_2 percentage using the following equation:

$$(\% CO_2)_{adj} = (\% CO_2)_{di} \left[\frac{100 + (\% EA)_i}{100 + (\% EA)_o}\right]$$

where:

$(\% CO_2)_{adj}$ is the adjusted outlet CO_2 percentage,

$(\% CO_2)_{di}$ is the percentage of CO_2 measured before the scrubber, dry basis,

$(\% EA)_i$ is the percentage of excess air at the inlet, and

$(\% EA)_o$ is the percentage of excess air at the outlet.

(d) Particulate matter emissions, expressed in g/dscm, shall be corrected to 12 percent CO_2 by using the following formula:

$$c_{12} = 12c/\% CO_2$$

where:

c_{12} is the concentration of particulate matter corrected to 12 percent CO_2, c is the concentration of particulate matter as measured by Method 5, and % CO_2 is the percentage of CO_2 as measured by Method 3, or when applicable, the adjusted outlet CO_2 percentage as determined by paragraph (c) of this section.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

[39 FR 20793, June 14, 1974]

Subpart F—Standards of Performance for Portland Cement Plants

§ 60.60 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities in portland cement plants: Kiln, clinker cooler, raw mill system, finish mill system, raw mill dryer, raw material storage, clinker storage, finished product storage, conveyor transfer points, bagging and bulk loading and unloading systems.

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(Secs. 111 and 301(a) of the Clean Air Act; sec. 4(a) of Pub. L. 91-604, 84 Stat. 1683; sec. 2 of Pub. L. 90-148, 81 Stat. 504 (42 U.S.C. 1857c-6, 1857g(a)))

[42 FR 37936, July 25, 1977]

§ 60.61 Definitions.

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

(a) "Portland cement plant" means any facility manufacturing portland cement by either the wet or dry process.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 20793, June 13, 1974]

§ 60.62 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any kiln any gases which:

(1) Contain particulate matter in excess of 0.15 kg per metric ton of feed (dry basis) to the kiln (0.30 lb per ton).

(2) Exhibit greater than 20 percent opacity.

(b) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any clinker cooler any gases which:

(1) Contain particulate matter in excess of 0.050 kg per metric ton of feed (dry basis) to the kiln (0.10 lb per ton).

(2) Exhibit 10 percent opacity, or greater.

(c) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility other than the kiln and clinker cooler any gases which exhibit 10 percent opacity, or greater.

[39 FR 20793, June 14, 1974, as amended at 39 FR 39874, Nov. 12, 1974; 40 FR 46258, Oct. 6, 1975]

§ 60.63 Monitoring of operations.

(a) The owner or operator of any portland cement plant subject to the provisions of this part shall record the daily production rates and kiln feed rates.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

[39 FR 20793, June 14, 1974, as amended at 43 FR 8800, Mar. 3, 1978]

§ 60.64 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with the standards prescribed in § 60.62 as follows:

(1) Method 5 for the concentration of particulate matter and the associated moisture content;

(2) Method 1 for sample and velocity traverses;

(3) Method 2 for velocity and volumetric flow rate; and

(4) Method 3 for gas analysis.

and substitute only for those leakage rates (L_i or L_p) which exceed L_a.

6.4 Volume of water vapor.

$$V_{w(std)} = V_{lc}\left(\frac{\rho_w}{M_w}\right)\left(\frac{RT_{std}}{P_{std}}\right) = K_2 V_{lc}$$

Equation 5-2

where:

K_2=0.001333 m³/ml for metric units
=0.04707 ft³/ml for English units.

6.5 Moisture Content.

$$B_{ws} = \frac{V_{w(std)}}{V_{m(std)} + V_{w(std)}}$$

Equation 5-3

NOTE.—In saturated or water droplet-laden gas streams, two calculations of the moisture content of the stack gas shall be made, one from the impinger analysis (Equation 5-3), and a second from the assumption of saturated conditions. The lower of the two values of B_w shall be considered correct. The procedure for determining the moisture content based upon assumption of saturated conditions is given in the Note of Section 1.2 of Method 4. For the purposes of this method, the average stack gas temperature from Figure 5-2 may be used to make this determination, provided that the accuracy of the in-stack temperature sensor is ±1° C (2° F).

6.6 Acetone Blank Concentration.

$$C_a = \frac{m_a}{V_a \rho_a}$$

Equation 5-4

6.7 Acetone Wash Blank.

$$W_a = C_a V_{aw} \rho_a$$

Equation 5-5

6.8 Total Particulate Weight. Determine the total particulate catch from the sum of the weights obtained from containers 1 and 2 less the acetone blank (see Figure 5-3). NOTE.—Refer to Section 4.1.5 to assist in calculation of results involving two or more filter assemblies or two or more sampling trains.

6.9 Particulate Concentration.

$$c_s = (0.001\ g/mg)\ (m_n/V_{m(std)})$$

Equation 5-6

6.10 Conversion Factors:

From	To	Multiply by
scf	m³	0.02832
g/ft³	gr/ft³	15.43
g/ft³	lb/ft³	2.205×10^{-3}
g/ft³	g/m³	35.31

6.11 Isokinetic Varition.

6.11.1 Calculation From Raw Data.

$$I = \frac{100\ T_s[K_3 V_{lc} + (V_m/T_m)\ (P_{bar} + \Delta H/13.6)]}{60\,\theta v_s P_s A_n}$$

Equation 5-7

where:

K_3=0.003454 mm Hg−m³/ml−°K for metric units.
=0.002669-in. Hg−ft³/ml−°R for English units.

6.11.2 Calculation From Intermediate Values.

$$I = \frac{T_s V_{m(std)} P_{std}\, 100}{T_{std} v_s \theta A_n P_s 60(1-B_{ws})} = K_4 \frac{T_s V_{m(std)}}{P_s V_s A_n \theta (1-B_{ws})}$$

Equation 5-8

where:

K_4=4.320 for metric units
=0.09450 for English units.

6.12 Acceptable Results. If 90 percent I <110< percent, the results are acceptable. If the results are low in comparison to the standard and I is beyond the acceptable range, or, if I is less than 90 percent, the Administrator may opt to accept the results. Use Citation 4 to make judgments. Otherwise, reject the results and repeat the test.

7. *Bibliography*

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METHOD 6—DETERMINATION OF SULFUR DIOXIDE EMISSIONS FROM STATIONARY SOURCES

1. *Principle and Applicability*

1.1 Principle. A gas sample is extracted from the sampling point in the stack. The sulfuric acid mist (including sulfur trioxide) and the sulfur dioxide are separated. The sulfur dioxide fraction is measured by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfur dioxide emissions from stationary sources. The minimum detectable limit of the method has been determined to be 3.4 milligrams (mg) of SO_2/m^3 (2.12×10^{-7} lb/ft^3). Although no upper limit has been established, tests have shown that concentrations as high as 80,000 mg/m^3 of SO_2 can be collected efficiently in two midget impingers, each containing 15 milliliters of 3 percent hydrogen peroxide, at a rate of 1.0 lpm for 20 minutes. Based on theoretical calculations, the upper concentration limit in a 20-liter sample is about 93,300 mg/m$_3$.

Possible interferents are free ammonia, water-soluble cations, and fluorides. The cations and fluorides are removed by glass wool filters and an isopropanol bubbler, and hence do not affect the SO_2 analysis. When samples are being taken from a gas stream with high concentrations of very find metallic fumes (such as in inlets to control devices), a high-efficiency glass fiber filter must be used in place of the glass wool plug (i.e., the one in the probe) to remove the cation interferents.

Free ammonia interferes by reacting with SO_2 to form particulate sulfite and by reacting with the indicator. If free ammonia is present (this can be determined by knowledge of the process and noticing white particulate matter in the probe and isopropanol bubbler), alternative methods, subject to the approval of the Administrator, U.S. Environmental Protection Agency, are required.

2. *Apparatus*

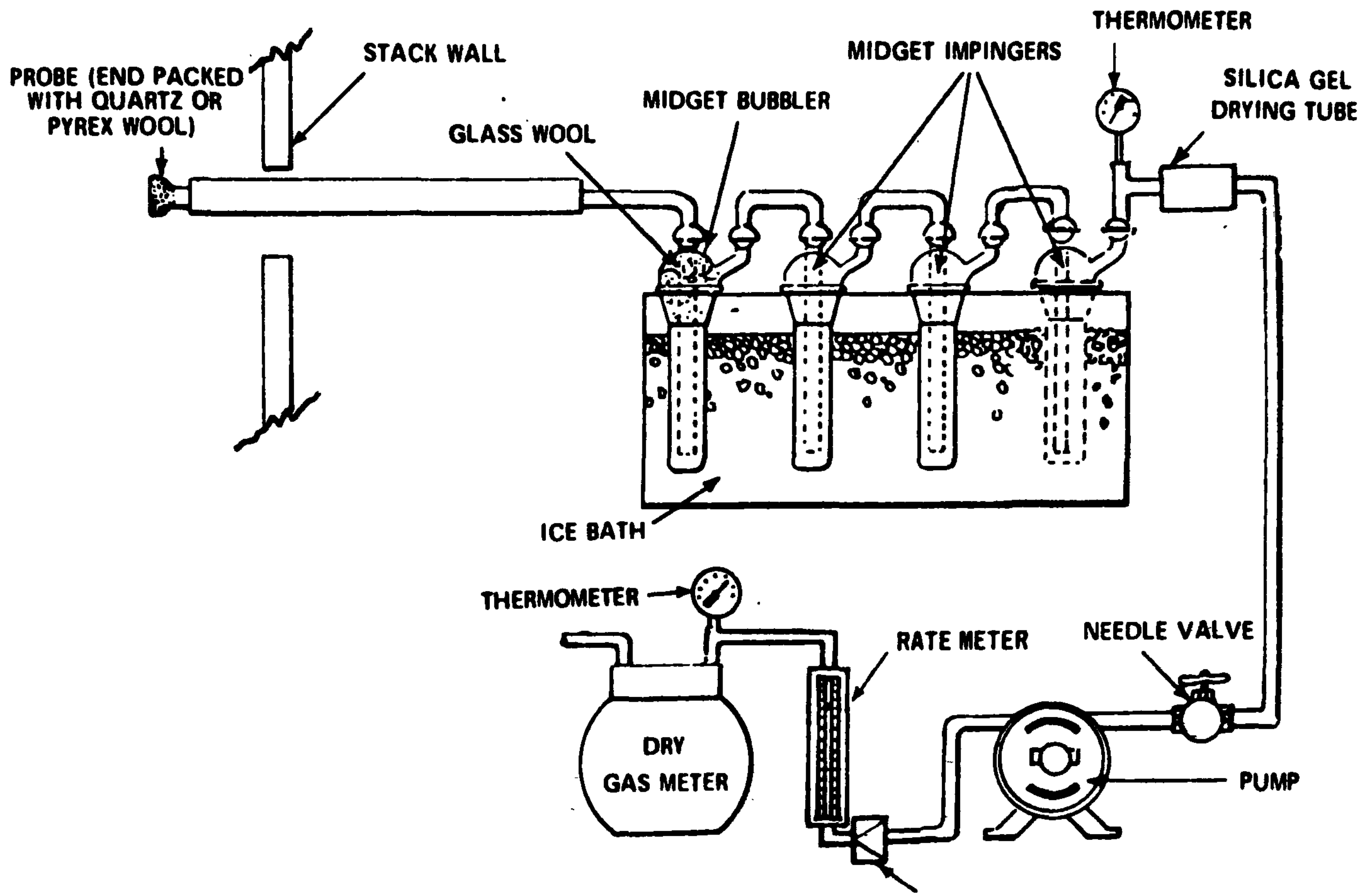

Figure 6-1. SO_2 sampling train.

2.1 Sampling. The sampling train is shown in Figure 6-1, and component parts are discussed below. The tester has the option of substituting sampling equipment described in Method 8 in place of the midget impinger equipment of Method 6. However, the Method 8 train must be modified to include a heated filter between the probe and isopropanol impinger, and the operation of the sampling train and sample analysis must be at the flow rates and solution volumes defined in Method 8.

The tester also has the option of determining SO_2 simultaneously with particulate matter and moisture determinations by (1) replacing the water in a Method 5 impinger system with 3 percent peroxide solution, or (2) by replacing the Method 5 water impinger system with a Method 8 isopropanol-filter-peroxide system. The analysis for SO_2 must be consistent with the procedure in Method 8.

2.1.1 Probe. Borosilicate glass, or stainless steel (other materials of construction may be used, subject to the approval of the Administrator), approximately 6-mm inside diameter, with a heating system to prevent water condensation and a filter (either in-stack or heated outstack) to remove particulate matter, including sulfuric acid mist. A plug of glass wool is a satisfactory filter.

2.1.2 Bubbler and Impingers. One midget bubbler, with medium-coarse glass frit and borosilicate or quartz glass wool packed in top (see Figure 6-1) to prevent sulfuric acid mist carryover, and three 30-ml midget impingers. The bubbler and midget impingers must be connected in series with leak-free glass connectors. silicone grease may be used, if necessary, to prevent leakage.

At the option of the tester, a midget impinger may be used in place of the midget bubbler.

Other collection absorbers and flow rates may be used, but are subject to the approval of the Administrator. Also, collection efficiency must be shown to be at least 99 percent for each test run and must be documented in the report. If the efficiency is found to be acceptable after a series of three tests, further documentation is not required. To conduct the efficiency test, an extra absorber must be added and analyzed separately. This extra absorber must not contain more than 1 percent of the total SO_2.

2.1.3 Glass Wool. Borosilicate or quartz.

2.1.4 Stopcock Grease. Acetone-insoluble, heatstable silicone grease may be used, if necessary.

2.1.5 Temperature Gauge. Dial thermometer, or equivalent, to measure temperature of gas leaving impinger train to within 1° C (2° F.)

2.1.6 Drying Tube. Tube packed with 6- to 16-mesh indicating type silica gel, or equivalent, to dry the gas sample and to protect the meter and pump. If the silica gel has been used previously, dry at 175° C (350° F) for 2 hours. New silica gel may be used as received. Alternatively, other types of decissants (equivalent or better) may be used, subject to approval of the Administrator.

2.1.7 Valve. Needle valve, to regulate sample gas flow rate.

2.1.8 Pump. Leak-free diaphragm pump, or equivalent, to pull gas through the train. Install a small surge tank between the pump and rate meter to eliminate the pulsation effect of the diaphragm pump on the rotameter.

2.1.9. Rate Meter. Rotameter, or equivalent, capable of measuring flow rate to within 2 percent of the selected flow rate of about 1000 cc/min.

2.1.10 Volume Meter. Dry gas meter, sufficiently accurate to measure the sample volume within 2 percent, calibrated at the selected flow rate and conditions actually encountered during sampling, and equipped with a temperature gauge (dial thermometer, or equivalent) capable of measuring temperature to within 3° C (5.4° F).

2.1.11 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 2.5 mm Hg (0.1 in. Hg). In many cases, the barometric reading may be obtained from a nearby national weather service station, in which case the station value (which is the absolute barometric pressure) shall be requested and an adjustment for elevation differences between the weather station and sampling point shall be applied at a rate of minus 2.5 mm Hg (0.1 in. Hg) per 30 m (100 ft) elevation increase or vice versa for elevation decrease.

2.112 Vacuum Gauge and Rotameter. At least 760 mm Hg (30 in. Hg) gauge and 0-40 cc/min rotameter, to be used for leak check of the sampling train.

2.2 Sample Recovey.

2.2.1 Wash bottles. Polyethylene or glass, 500 ml, two.

2.2.2 Storage Bottles. Polyethylene, 100 ml, to store impinger samples (one per sample).

2.3 Analysis.

2.3.1 Pipettes. Volumetric type, 5-ml, 20-ml (one per sample), and 25-ml sizes.

2.3.2 Volumetric Flasks. 100-ml size (one per sample) and 1000 ml size.

2.3.3 Burettes. 5- and 50-ml sizes.

2.3.4 Erlenmeyer Flasks. 250 ml-size (one for each sample, blank, and standard).

2.3.5 Dropping Bottle. 125-ml size, to add indicator.

2.3.6 Graduated Cylinder. 100-ml size.

2.3.7 Spectrophotometer. To measure absorbance at 352 nanometers.

3. *Reagents*

Unless otherwise indicated, all reagents must conform to the specifications established by the Committee on Analytical Reagents of the American Chemical Society. Where such specifications are not available, use the best available grade.

3.1 Sampling.

3.1.1 Water. Deionized, distilled to conform to ASTM specification D1193-74, Type 3. At the option of the analyst, the $KMnO_4$ test for oxidizable organic matter may be omitted when high concentrations of organic matter are not expected to be present.

3.1.2 Isopropanol, 80 percent. Mix 80 ml of isopropanol with 20 ml of deionized, distilled water. Check each lot of isopropanol for peroxide impurities as follows: shake 10 ml of isopropanol with 10 ml of freshly prepared 10 percent potassium iodide solution. Prepare a blank by similarly treating 10 ml of distilled water. After 1 minute, read the absorbance at 352 nanometers on a spectrophotometer. If absorbance exceeds 0.1, reject alcohol for use.

Peroxides may be removed from isopropanol by redistilling or by passage through a column of activated alumina; however, reagent grade isopropanol with suitably low peroxide levels may be obtained from commercial sources. Rejection of contaminated lots may, therefore, be a more efficient procedure.

3.1.3 Hydrogen Peroxide, 3 Percent. Dilute 30 percent hydrogen peroxide 1:9 (v/v) with deionized, distilled water (30 ml is needed per sample). Prepare fresh daily.

3.1.4 Potassium Iodide Solution, 10 Percent. Dissolve 10.0 grams KI in deionized, distilled water and dilute to 100 ml. Prepare when needed.

3.2 Sample Recovery.

3.2.1 Water. Deionized, distilled, as in 3.1.1.

3.2.2 Isopropanol, 80 Percent. Mix 80 ml of isopropanol with 20 ml of deionized, distilled water.

3.3 Analysis.

3.3.1 Water. Deionized, distilled, as in 3.1.1.

3.3.2 Isopropanol, 100 percent.

3.3.3 Thorin Indicator. 1-(o-arsonophenylazo)-2-naphthol-3,6-disulfonic acid, disodium salt, or equivalent. Dissolve 0.20 g in 100 ml of deionized, distilled water.

3.3.4 Barium Perchlorate Solution, 0.0100 N. Dissolve 1.95 g of barium perchlorate trihydrate $[Ba(ClO_4)_2 \cdot 3H_2O]$ in 200 ml distilled water and dilute to 1 liter with isopropanol. Alternatively, 1.22 g of $[BaCl_2 \cdot 2H_2O]$ may be used instead of the perchlorate. Standardize as in Section 5.5.

3.3.5 Sulfuric Acid Standard, 0.0100 N. Purchase or standardize to ± 0.0002 N against 0.0100 N NaOH which has previously been standardized against potassium acid phthalate (primary standard grade).

4. *Procedure.*

4.1 Sampling.

4.1.1 Preparation of collection train. Measure 15 ml of 80 percent isopropanol into the midget bubbler and 15 ml of 3 percent hydrogen peroxide into each of the first two midget impingers. Leave the final midget impinger dry. Assemble the train as shown in Figure 6-1. Adjust probe heater to a temperature sufficient to prevent water condensation. Place crushed ice and water around the impingers.

4.1.2 Leak-check procedure. A leak check prior to the sampling run is optional; however, a leak check after the sampling run is mandatory. The leak-check procedure is as follows:

Temporarily attach a suitable (e.g., 0–40 cc/min) rotameter to the outlet of the dry gas meter and place a vacuum gauge at or near the probe inlet. Plug the probe inlet, pull a vaccum of at least 250 mm Hg (10 in. Hg), and note the flow rate as indicated by the rotameter. A leakage rate not in excess of 2 percent of the average sampling rate is acceptable.

NOTE: Carefully release the probe inlet plug before turning off the pump.

It is suggested (not mandatory) that the pump be leak-checked separately, either prior to or after the sampling run. If done prior to the sampling run, the pump leak-check shall precede the leak check of the sampling train described immediately above; if done after the sampling run, the pump leak-check shall follow the train leak-check. To leak check the pump, proceed as follows: Disconnect the drying tube from the probe-impinger assembly. Place a vacuum gauge at the inlet to either the trying tube or the pump, pull a vacuum of 250 mm (10 in.) Hg, plug or pinch off the outlet of the flow meter and then turn off the pump. The vacuum should remain stable for at least 30 seconds.

Other leak-check procedures may be used, subject to the approval of the Adminstrator, U.S. Environmental Protection Agency.

4.1.3 Sample collection. Record the initial dry gas meter reading and barometric pressure. To begin sampling, position the tip of the probe at the sampling point, connect the probe to the bubbler, and start the pump. Adjust the sample flow to a constant rate of approximately 1.0 liter/min as indicated by the rotameter. Maintain this constant rate (± 10 percent) during the entire sampling run. Take readings (dry gas meter, tempertures at dry gas meter and at impinger outlet and rate meter) at least every 5 minutes. Add more ice during the run to keep the temperture of the gases leaving the last impinger at 20° C (68° F) or less. At the conclusion of each run, turn off the pump, remove probe from the stack, and record the final readings. Conduct a leak check as in Section 4.1.2 (This leak check is mandatory.) If a leak is found, void the test run, or use procedures acceptable to the Administrator to adjust the sample volume for the leakage. Drain the ice bath, and purge the remaining part of the train by drawing clean ambient air through the system for 15 minutes at the sampling rate.

Clean ambient air can be provided by passing air through a charcoal filter or through an extra midget impinger with 15 ml of 3 percent H_2O_2. The tester may opt to simply use ambient air, without purification.

4.2 Sample Recovery. Disconnect the impingers after purging. Discard the contents of the midget bubbler. Pour the contents of the midget impingers into a leak-free polyethylene bottle for shipment. Rinse the three midget impingers and the connecting tubes with deionized, distilled water, and add the washings to the same storage container. Mark the fluid level. Seal and identify the sample container.

4.3 Sample Analysis. Note level of liquid in container, and confirm whether any sample was lost during shipment; note this on analytical data sheet. If a noticeable amount of leakage has occurred, either void the sample or use methods, subject to the approval of the Administrator, to correct the final results.

Transfer the contents of the storage container to a 100-ml volumetric flask and dilute to exactly 100 ml with deionized, distilled water. Pipette a 20-ml aliquot of this solution into a 250-ml Erlenmeyer flask, add 80 ml of 100 percent isopropanol and two to four drops of thorin indicator, and titrate to a pink endpoint using 0.0100 N barium perchlorate. Repeat and average the titration volumes. Run a blank with each series of samples. Replicate titrations must agree within 1 percent or 0.2 ml, whichever is larger.

(NOTE.—Protect the 0.0100 N barium perchlorate solution from evaporation at all times.)

5. *Calibration*

5.1 Metering System.

5.1.1 Initial Calibration. Before its initial use in the field, first leak check the metering system (drying tube, needle valve, pump, rotameter, and dry gas meter) as follows: place a vacuum gauge at the inlet to the drying tube and pull a vaccum of 250 mm (10 in.) Hg; plug or pinch off the outlet of the flow meter, and then turn off the pump. The vaccum shall remain stable for at least 30 seconds. Carefully release the vaccum gauge before releasing the flow meter end.

Next, calibrate the metering system (at the sampling flow rate specified by the method) as follows: connect an appropriately sized wet test meter (e.g., 1 liter per revolution) to the inlet of the drying tube. Make three independent calibration runs, using at least five revolutions of the dry gas meter per run. Calculate the calibration factor, Y (wet test meter calibration volume divided by the dry gas meter volume, both volumes adjusted to the same reference temperature and pressure), for each run, and average the results. If any Y value deviates by more than 2 percent from the average, the metering system is unacceptable for use. Otherwise, use the average as the calibration factor for subsequent test runs.

5.1.2 Post-Test Calibration Check. After each field test series, conduct a calibration check as in Section 5.1.1 above, except for the following variations: (a) the leak check is not to be conducted, (b) three, or more revolutions of the dry gas meter may be used, and (c) only two independent runs need be made. If the calibration factor does not deviate by more than 5 percent from the initial calibration factor (determined in Section 5.1.1), then the dry gas meter volumes obtained during the test series are acceptable. If the calibration factor deviates by more than 5 percent, recalibrate the metering system as in Section 5.1.1, and for the calculations, use the calibration factor (initial or recalibration) that yields the lower gas volume for each test run.

5.2 Thermometers. Calibrate against mercury-in-glass thermometers.

5.3 Rotameter. The rotameter need not be calibrated but should be cleaned and maintained according to the manufacturer's instruction.

5.4 Barometer. Calibrate against a mercury barometer.

5.5 Barium Perchlorate Solution. Standardize the barium perchlorate solution against 25 ml of standard sulfuric acid to which 100 ml of 100 percent isopropanol has been added.

6. *Calculations*

Carry out calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after final calculation.

6.1 Nomenclature.

C_{SO_2} = Concentration of sulfur dioxide, dry basis corrected to standard conditions, mg/dscm (lb/dscf).

N = Normality of barium perchlorate titrant, milliequivalents/ml.

P_{bar} = Barometric pressure at the exit orifice of the dry gas meter, mm Hg (in. Hg).

P_{std} = Standard absolute pressure, 760 mm Hg (29.92 in. Hg).

T_m = Average dry gas meter absolute temperature, °K (°R).
T_{std} = Standard absolute temperature, 293° K (528° R).
V_a = Volume of sample aliquot titrated, ml.
V_m = Dry gas volume as measured by the dry gas meter, dcm (dcf).
$V_{m(std)}$ = Dry gas volume measured by the dry gas meter, corrected to standard conditions, dscm (dscf).
V_{soln} = Total volume of solution in which the sulfur dioxide sample is contained, 100 ml.
V_t = Volume of barium perchlorate titrant used for the sample, ml (average or replicate titrations).
V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.
Y = Dry gas meter calibration factor.
32.03 = Equivalent weight of sulfur dioxide.

6.2 Dry sample gas volume, corrected to standard conditions.

$$V_{m(std)} = V_m Y \left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar}}{P_{std}}\right) = K_1 Y \frac{V_m P_{bar}}{T_m}$$

Equation 6-1

where:
K_1 = 0.3858° K/mm Hg for metric units.
= 17.64° R/in. Hg for English units.

6.3 Sulfur dioxide concentration.

$$C_{SO_2} = K_2 \frac{(V_t - V_{tb})\, N\left(\frac{V_{soln}}{V_a}\right)}{V_{m(std)}}$$

Equation 6-2

where:
K_2 = 32.03 mg/meq. for metric units.
= 7.061×10^{-5} lb/meq. for English units.

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Method 7—Determination of Nitrogen Oxide Emissions From Stationary Sources

1. *Principle and Applicability*

1.1 Principle. A grab sample is collected in an evacuated flask containing a dilute sulfuric acid-hydrogen peroxide absorbing solution, and the nitrogen oxides, except nitrous oxide, are measured colorimeterically using the phenoldisulfonic acid (PDS) procedure.

1.2 Applicability. This method is applicable to the measurement of nitrogen oxides emitted from stationary sources. The range of the method has been determined to be 2 to 400 milligrams NO_x (as NO_2) per dry standard cubic meter, without having to dilute the sample.

2. *Apparatus*

2.1 Sampling (see Figure 7-1). Other grab sampling systems or equipment, capable of measuring sample volume to within ±2.0 percent and collecting a sufficient sample volume to allow analytical reproducibility to within ±5 percent, will be considered acceptable alternatives, subject to approval of the Administrator, U.S. Environmental Protection Agency. The following equipment is used in sampling:

2.1.1 Probe. Borosilicate glass tubing, sufficiently heated to prevent water condensation and equipped with an in-stack or out-stack filter to remove particulate matter (a plug of glass wool is satisfactory for this purpose). Stainless steel or Teflon [3] tubing may also be used for the probe. Heating is not necessary if the probe remains dry during the purging period.

[3] Mention of trade names or specific products does not constitue endorsement by the Environmental Protection Agency.

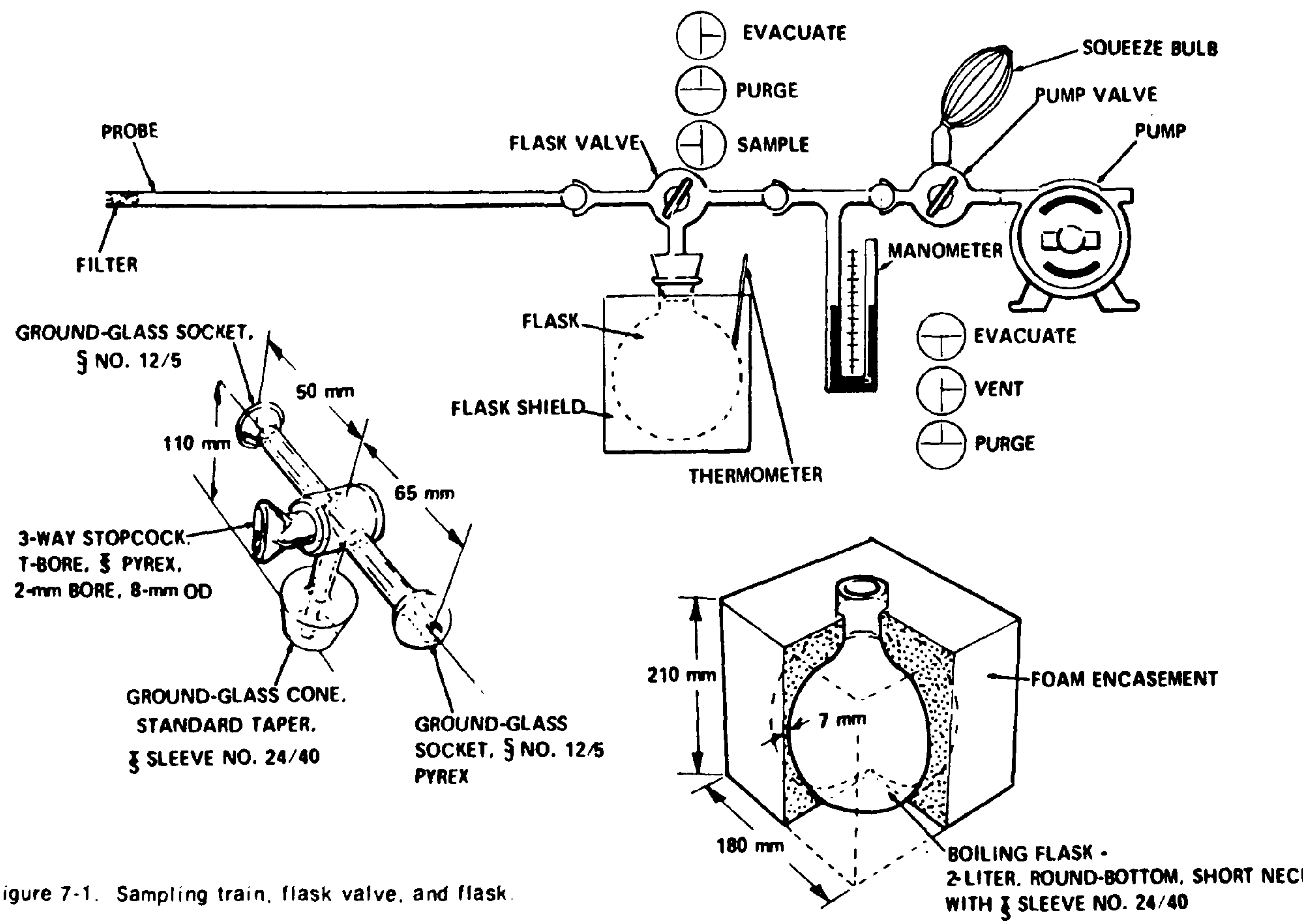

Figure 7-1. Sampling train, flask valve, and flask.

Appendix B. Applicable 40CFR51 Minimum Emission Monitoring Requirements

Sources subject to sulfur dioxide (SO_2) continuous emissions monitoring are reproduced below from Appendix P of 40CFR51, July 1, 1979.

APPENDIX P—MINIMUM EMISSION MONITORING REQUIREMENTS

1.0 Purpose. This Appendix P sets forth the minimum requirements for continuous emission monitoring and recording that each State Implementation Plan must include in order to be approved under the provisions of 40 CFR 51.19(e). These requirements include the source categories to be affected; emission monitoring, recording, and reporting requirements for those sources; performance specifications for accuracy, reliability, and durability of acceptable monitoring systems; and techniques to convert emission data to units of the applicable State emission standard. Such data must be reported to the State as an indication of whether proper maintenance and operating procedures are being utilized by source operators to maintain emission levels at or below emission standards. Such data may be used directly or indirectly for compliance determination or any other purpose deemed appropriate by the State. Though the monitoring requirements are specified in detail, States are given some flexibility to resolve difficulties that may arise during the implementation of these regulations.

1.1 *Applicability.*

The State plan shall require the owner or operator of an emission source in a category listed in this Appendix to: (1) Install, calibrate, operate, and maintain all monitoring equipment necessary for continuously monitoring the pollutants specified in this Appendix for the applicable source category; and (2) complete the installation and performance tests of such equipment and begin monitoring and recording within 18 months of plan approval or promulgation. The source categories and the respective monitoring requirements are listed below.

1.1.1 Fossil fuel-fired steam generators, as specified in paragraph 2.1 of this appendix, shall be monitored for opacity, nitrogen oxides emissions, sulfur dioxide emissions, and oxygen or carbon dioxide.

1.1.2 Fluid bed catalytic cracking unit catalyst regenerators, as specified in paragraph 2.4 of this appendix, shall be monitored for opacity.

1.1.3 Sulfuric acid plants, as specified in paragraph 2.3 of this appendix, shall be monitored for sulfur dioxide emissions.

1.1.4 Nitric acid plants, as specified in paragraph 2.2 of this appendix, shall be monitored for nitrogen oxides emissions.

1.2 *Exemptions.*

The States may include provisions within their regulations to grant exemptions from the monitoring requirements of paragraph 1.1 of this appendix for any source which is:

1.2.1 subject to a new source performance standard promulgated in 40 CFR Part 60 pursuant to Section 111 of the Clean Air Act; or

1.2.2 not subject to an applicable emission standard of an approved plan; or

1.2.3 scheduled for retirement within 5 years after inclusion of monitoring requirements for the source in Appendix P, provided that adequate evidence and guarantees are provided that clearly show that the source will cease operations prior to such date.

1.3 *Extensions.*

States may allow reasonable extensions of the time provided for installation of monitors for facilities unable to meet the prescribed timeframe (i.e., 18 months from plan approval or promulgation) provided the owner or operator of such facility demonstrates that good faith efforts have been made to obtain and install such devices within such prescribed timeframe.

1.4 *Monitoring System Malfunction.*

The State plan may provide a temporary exemption from the monitoring and reporting requirements of this appendix during any period of monitoring system malfunction, provided that the source owner or operator shows, to the satisfaction of the State, that the malfunction was unavoidable and is being repaired as expeditiously as practicable.

2.0 *Minimum Monitoring Requirement.*

States must, as a minimum, require the sources listed in paragraph 1.1 of this appendix to meet the following basic requirements.

2.1 *Fossil fuel-fired steam generators.*

Each fossil fuel-fired steam generator, except as provided in the following subparagraphs, with an annual average capacity factor of greater than 30 percent, as reported to the Federal Power Commission for calendar year 1974, or as otherwise demonstrated to the State by the owner or operator, shall conform with the following monitoring requirements when such facility is subject to an emission standard of an applicable plan for the pollutant in question.

2.1.1 A continuous monitoring system for the measurement of opacity which meets the performance specifications of paragraph 3.1.1 of this appendix shall be installed, calibrated, maintained, and operated in accordance with the procedures of this appendix by the owner or operator of any such steam generator of greater than 250 million BTU per hour heat input except where:

2.1.1.1 gaseous fuel is the only fuel burned, or

2.1.1.2 oil or a mixture of gas and oil are the only fuels burned and the source is able to comply with the applicable particulate matter and opacity regulations without utilization of particulate matter collection equipment, and where the source has never been found, through any administrative or judicial proceedings, to be in violation of any visible emission standard of the applicable plan.

2.1.2 A continuous monitoring system for the measurement of sulfur dioxide which meets the performance specifications of paragraph 3.1.3 of this appendix shall be installed, calibrated, maintained, and operated on any fossil fuel-fired steam generator of greater than 250 million BTU per hour heat input which has installed sulfur dioxide pollutant control equipment.

2.1.3 A continuous monitoring system for the measurement of nitrogen oxides which meets the performance specification of paragraph 3.1.2 of this appendix shall be installed, calibrated, maintained, and operated on fossil fuel-fired steam generators of greater than 1000 million BTU per hour heat input when such facility is located in an Air Quality Control Region where the Administrator has specifically determined that a control strategy for nitrogen dioxide is necessary to attain the national standards, unless the source owner or operator demonstrates during source compliance tests as required by the State that such a source emits nitrogen oxides at levels 30 percent or more below the emission standard within the applicable plan.

2.1.4 A continuous monitoring system for the measurement of the percent oxygen or carbon dioxide which meets the performance specifications of paragraphs 3.1.4 or 3.1.5 of this appendix shall be installed, calibrated, operated, and maintained on fossil fuel-fired steam generators where measurements of oxygen or carbon dioxide in the flue gas are required to convert either sulfur dioxide or nitrogen oxides continuous emission monitoring data, or both, to units of the emission standard within the applicable plan.

2.2 *Nitric acid plants.*

Each nitric acid plant of greater than 300 tons per day production capacity, the production capacity being expressed as 100 percent acid, located in an Air Quality Control Region where the Administrator has specifically determined that a control strategy for nitrogen dioxide is necessary to attain the national standard shall install, calibrate, maintain, and operate a continuous monitoring system for the measurement of nitrogen oxides which meets the performance specifications of paragraph 3.1.2 for each nitric acid producing facility within such plant.

2.3 *Sulfuric acid plants.*

Each Sulfuric acid plant of greater than 300 tons per day production capacity, the production being expressed as 100 percent acid, shall install, calibrate, maintain and operate a continuous monitoring system for the measurement of sulfur dioxide which meets the performance specifications of 3.1.3 for each sulfuric acid producing facility within such plant.

2.4 *Fluid bed catalytic cracking unit catalyst regenerators at petroleum refineries.*

Each catalyst regenerator for fluid bed catalytic cracking units of greater than 20,000 barrels per day fresh feed capacity shall install, calibrate, maintain, and operate a continuous monitoring system for the measurement of opacity which meets the performance specifications of 3.1.1.

3.0 *Minimum specifications.*

All State plans shall require owners or operators of monitoring equipment installed to comply with this Appendix, except as provided in paragraph 3.2, to demonstrate compliance with the following performance specifications.

3.1 *Performance specifications.*

The performance specifications set forth in Appendix B of Part 60 are incorporated herein by reference, and shall be used by States to determine acceptability of monitoring equipment installed pursuant to this Appendix except that (1) where reference is made to the "Administrator" in Appendix B, Part 60, the term "State" should be inserted for the purpose of this Appendix (e.g., in Performance Specification 1, 1.2, " * * * monitoring systems subject to approval by the *Administrator,*" should be interpreted as, "* * * monitoring systems subject to approval by the *State*"), and (2) where reference is made to the "Reference Method" in Appendix B, Part 60, the State may allow the use of either the State approved reference method or the Federally approved reference method as published in Part 60 of this Chapter. The Performance Specifications to be used with each type of monitoring system are listed below.

3.1.1 Continuous monitoring systems for measuring opacity shall comply with Performance Specification 1.

3.1.2 Continuous monitoring systems for measuring nitrogen oxides shall comply with Performance Specification 2.

3.1.3 Continuous monitoring systems for measuring sulfur dioxide shall comply with Performance Specification 2.

3.1.4 Continuous monitoring systems for measuring oxygen shall comply with Performance Specification 3.

3.1.5 Continuous monitoring systems for measuring carbon dioxide shall comply with Performance Specification 3.

3.2 *Exemptions.*

Any source which has purchased an emission monitoring system(s) prior to September 11, 1974, may be exempt from meeting such test procedures prescribed in Appendix B of Part 60 for a period not to exceed five years from plan approval or promulgation.

3.3 *Calibration Gases.*

For nitrogen oxides monitoring systems installed on fossil fuel-fired steam gener-

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ators the pollutant gas used to prepare calibration gas mixtures (Section 2.1, Performance Specification 2, Appendix B, Part 60) shall be nitric oxide (NO). For nitrogen oxides monitoring systems, installed on nitric acid plants the pollutant gas used to prepare calibration gas mixtures (Section 2.1, Performance Specification 2, Appendix B, Part 60 of this Chapter) shall be nitrogen dioxide (NO_2). These gases shall also be used for daily checks under paragraph 3.7 of this appendix as applicable. For sulfur dioxide monitoring systems installed on fossil fuel-fired steam generators or sulfuric acid plants the pollutant gas used to prepare calibration gas mixtures (Section 2.1, Performance Specification 2, Appendix B, Part 60 of this Chapter) shall be sulfur dioxide (SO_2). Span and zero gases should be traceable to National Bureau of Standards reference gases whenever these reference gases are available. Every six months from date of manufacture, span and zero gases shall be reanalyzed by conducting triplicate analyses using the reference methods in Appendix A, Part 60 of this chapter as follows: for sulfur dioxide, use Reference Method 6; for nitrogen oxides, use Reference Method 7; and for carbon dioxide or oxygen, use Reference Method 3. The gases may be analyzed at less frequent intervals if longer shelf lives are guaranteed by the manufacturer.

3.4 *Cycling times.*

Cycling times include the total time a monitoring system requires to sample, analyze and record an emission measurement.

3.4.1 Continuous monitoring systems for measuring opacity shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 10-second period.

3.4.2 Continuous monitoring systems for measuring oxides of nitrogen, carbon dioxide, oxygen, or sulfur dioxide shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

3.5 *Monitor location.*

State plans shall require all continuous monitoring systems or monitoring devices to be installed such that representative measurements of emissions or process parameters (i.e., oxygen, or carbon dioxide) from the affected facility are obtained. Additional guidance for location of continuous monitoring systems to obtain representative samples are contained in the applicable Performance Specifications of Appendix B of Part 60 of this Chapter.

3.6 *Combined effluents.*

When the effluents from two or more affected facilities of similar design and operating characteristics are combined before being released to the atmosphere, the State plan may allow monitoring systems to be installed on the combined effluent. When the affected facilities are not of similar design and operating characteristics, or when the effluent from one affected facility is released to the atmosphere through more than one point, the State should establish alternate procedures to implement the intent of these requirements.

3.7 *Zero and drift.*

State plans shall require owners or operators of all continuous monitoring systems installed in accordance with the requirements of this Appendix to record the zero and span drift in accordance with the method prescribed by the manufacturer of such instruments; to subject the instruments to the manufacturer's recommended zero and span check at least once daily unless the manufacturer has recommended adjustments at shorter intervals, in which case such recommendations shall be followed; to adjust the zero and span whenever the 24-hour zero drift or 24-hour calibration drift limits of the applicable performance specifications in Appendix B of Part 60 are exceeded; and to adjust continuous monitoring systems referenced by paragraph 3.2 of this Appendix whenever the 24-hour zero drift or 24-hour calibration drift exceed 10 percent of the emission standard.

3.8 *Span.*

Instrument span should be approximately 200 per cent of the expected instrument data display output corresponding to the emission standard for the source.

3.9 *Alternative procedures and requirements.*

In cases where States wish to utilize different, but equivalent, procedures and requirements for continuous monitoring systems, the State plan must provide a description of such alternative procedures for approval by the Administrator. Some examples of situations that may require alternatives follow:

3.9.1 Alternative monitoring requirements to accommodate continuous monitoring systems that require corrections for stack moisture conditions (e.g., an instrument measuring steam generator SO_2 emissions on a wet basis could be used with an instrument measuring oxygen concentration on a dry basis if acceptable methods of measuring stack moisture conditions are used to allow accurate adjustments of the measured SO_2 concentration to dry basis.)

3.9.2 Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternative locations will enable accurate and representative measurements.

3.9.3 Alternative procedures for performing calibration checks (e.g., some instruments may demonstrate superior drift characteristics that require checking at less frequent intervals).

3.9.4 Alternative monitoring requirements when the effluent from one affected facility or the combined effluent from two or more identical affected facilities is released to the atmosphere through more than one point (e.g., an extractive, gaseous monitoring system used at several points may be approved if the procedures recommended are suitable for generating accurate emission averages).

3.9.5 Alternative continuous monitoring systems that do not meet the spectral response requirements in Performance Specification 1, Appendix B of Part 60, but adequately demonstrate a definite and consistent relationship between their measurements and the opacity measurements of a system complying with the requirements in Performance Specification 1. The State may require that such demonstration be performed for each affected facility.

4.0 *Minimum data requirements.*

The following paragraphs set forth the minimum data reporting requirements necessary to comply with § 51.19(e) (3) and (4).

4.1 The State plan shall require owners or operators of facilities required to install continuous monitoring systems to submit a written report of excess emissions for each calendar quarter and the nature and cause of the excess emissions, if known. The averaging period used for data reporting should be established by the State to correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the pollutant/source category in question. The required report shall include, as a minimum, the data stipulated in this Appendix.

4.2 For opacity measurements, the summary shall consist of the magnitude in actual percent opacity of all one-minute (or such other time period deemed appropriate by the State) averages of opacity greater than the opacity standard in the applicable plan for each hour of operation of the facility. Average values may be obtained by integration over the averaging period or by arithmetically averaging a minimum of four equally spaced, instantaneous opacity measurements per minute. Any time period exempted shall be considered before determining the excess averages of opacity (e.g., whenever a regulation allows two minutes of opacity measurements in excess of the standard, the State shall require the source to report all opacity averages, in any one hour, in excess of the standard, minus the two-minute exemption). If more than one opacity standard applies, excess emissions data must be submitted in relation to all such standards.

4.3 For gaseous measurements the summary shall consist of emission averages, in the units of the applicable standard, for each averaging period during which the applicable standard was exceeded.

4.4 The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustments shall be reported. The State may require proof of continuous monitoring system performance whenever system repairs or adjustments have been made.

4.5 When no excess emissions have occurred and the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be included in the report.

4.6 The State plan shall require owners or operators of affected facilities to maintain a file of all information reported in the quarterly summaries, and all other data collected either by the continuous monitoring system or as necessary to convert monitoring data to the units of the applicable standard for a minimum of two years from the date of collection of such data or submission of such summaries.

5.0 *Data Reduction.*

The State plan shall require owners or operators of affected facilities to use the following procedures for converting monitoring data to units of the standard where necessary.

5.1 For fossil fuel-fired steam generators the following procedures shall be used to convert gaseous emission monitoring data in parts per million to g/million cal (lb/million BTU) where necessary:

5.1.1 When the owner or operator of a fossil fuel-fired steam generator elects under subparagraph 2.1.4 of this Appendix to measure oxygen in the flue gases, the measurements of the pollutant concentration and oxygen concentration shall each be on a dry basis and the following conversion procedure used:

$$E = CF\,[20.9/20.9 - \%O_2]$$

5.1.2 When the owner or operator elects under paragraph 2.1.4 of this Appendix to measure carbon dioxide in the flue gases, the measurement of the pollutant concentration and the carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure used:

$$E = CF_c\,(100/\%\ CO_2)$$

5.1.3 The values used in the equations under paragraph 5.1 are derived as follows:

E = pollutant emission, g/million cal (lb/million BTU),

C = pollutant concentration, g/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each hourly period by 4.16×10^{-5} M g/dscm per ppm (2.64×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64 for sulfur dioxide and 46 for oxides of nitrogen.

$\%O_2$, $\%CO_2$ = Oxygen or carbon dioxide volume (expressed as percent) determined with equipment specified under paragraph 4.1.4 of this appendix.

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 carbon dioxide generated to the calorific value of the fuel combusted (F_c) respectively. Values of F and F_c are given in § 60.45(f) of Part 60, as applicable.

5.2 For sulfuric acid plants the owner or operator shall;

5.2.1 establish a conversion factor three times daily according to the procedures to § 60.84(b) of this chapter;

5.2.2 multiply the conversion factor by the average sulfur dioxide concentration in the flue gases to obtain average sulfur dioxide emissions in Kg/metric ton (lb/short ton); and

5.2.3 report the average sulfur dioxide emission for each averaging period in excess of the applicable emission standard in the quarterly summary.

5.3 For nitric acid plants the owner or operator shall;

5.3.1 establish a conversion factor according to the procedures of § 60.73(b) of this chapter;

5.3.2 multiply the conversion factor by the average nitrogen oxides concentration in the flue gases to obtain the nitrogen oxides emissions in the units of the applicable standard;

5.3.3 report the average nitrogen oxides emission for each averaging period in excess of the applicable emission standard, in the quarterly summary.

5.4 Any State may allow data reporting or reduction procedures varying from those set forth in this Appendix if the owner or operator of a source shows to the satisfaction of the State that his procedures are at least as accurate as those in this Appendix. Such procedures may include but are not limited to, the following:

5.4.1 Alternative procedures for computing emission averages that do not require integration of data (e.g., some facilities may demonstrate that the variability of their emissions is sufficiently small to allow accurate reduction of data based upon computing averages from equally spaced data points over the averaging period).

5.4.2 Alternative methods of converting pollutant concentration measurements to the units of the emission standards.

6.0 *Special Consideration.*

The State plan may provide for approval, on a case-by-case basis, of alternative monitoring requirements different from the provisions of Parts 1 through 5 of this Appendix if the provisions of this Appendix (i.e., the installation of a continuous emission monitoring system) cannot be implemented by a source due to physical plant limitations or extreme economic reasons. To make use of this provision, States must include in their plan specific criteria for determining those physical limitations or extreme economic situations to be considered by the State. In such cases, when the State exempts any source subject to this Appendix by use of this provision from installing continuous emission monitoring systems, the State shall set forth alternative emission monitoring and reporting requirements (e.g., periodic manual stack tests) to satisfy the intent of these regulations. Examples of such special cases include, but are not limited to, the following:

6.1 Alternative monitoring requirements may be prescribed when installation of a continuous monitoring system or monitoring device specified by this Appendix would not provide accurate determinations of emissions (e.g., condensed, uncombined water vapor may prevent an accurate determination of opacity using commercially available continuous monitoring systems).

6.2 Alternative monitoring requirements may be prescribed when the affected facility is infrequently operated (e.g., some affected facilities may operate less than one month per year).

6.3 Alternative monitoring requirements may be prescribed when the State determines that the requirements of this Appendix would impose an extreme economic burden on the source owner or operator.

6.4 Alternative monitoring requirements may be prescribed when the State determines that monitoring systems prescribed by this Appendix cannot be installed due to physical limitations at the facility.

[40 FR 46247, Oct. 6, 1975]

APPENDIX Q [Reserved]

APPENDIX C. NOTICES OF SIP CHANGES AFFECTING SO_2 REGULATIONS

Since the compilation of this document, numerous revisions have been made to the approved SIP regulations for sulfur dioxide. Listed below are the affected States, as well as the date of each revision and the appropriate Federal Register citation. For further information, contact the appropriate State control agency or EPA Regional Office.

State	Date	Federal Register Volume 46
Massachusetts	1/19/81	p. 4916
New Jersey	1/19/81	p. 4918
Rhode Island	1/21/81	p. 5980
Indiana	1/27/81	p. 8474
Massachusetts	1/27/81	p. 8475
Michigan	1/27/81	p. 8476
New York	1/27/81	p. 8477
Ohio	1/27/81	p. 8481
D.C.	1/30/81	p. 9947
Ohio	3/19/81	p. 17554
Massachusetts	3/19/81	p. 17551
Ohio	3/19/81	p. 17550
New York	3/19/81	p. 17555
Minnesota	4/8/81	p. 20996
Ohio	4/14/81	p. 21767
Connecticut	4/27/81	p. 23412
Ohio	4/29/81	p. 23926
Michigan	5/1/81	p. 24560
Ohio	5/4/81	p. 24926
Michigan	5/14/81	p. 26641
Ohio	5/26/81	p. 28157
Ohio	6/12/81	p. 31012
Kentucky	6/15/81	p. 31260
Michigan	7/2/81	p. 34584
Ohio	7/22/81	p. 37642
Massachusetts	8/11/81	p. 40678
Ohio	8/26/81	p. 43045
New Mexico	8/27/81	p. 43152

State	Date	Federal Register Volume 46
Pennsylvania	8/28/81	p. 43423
Virgin Islands	9/3/81	p. 44188
Maryland	9/4/81	p. 44448
Massachusetts	9/17/81	p. 46131
Pennsylvania	9/17/81	p. 46133
New York	9/24/81	p. 47069
Ohio	10/6/81	p. 49123
Connecticut	10/23/81	p. 51914
New Jersey	11/3/81	p. 54542
Alabama	11/6/81	p. 55105
Pennsylvania	11/13/81	p. 55975
Connecticut	11/18/81	p. 56612