Compliance and performance test methods

Source	SOx - §60.45b	NOx - §60.46b	PM - §60.46b
General	1.) The SOx emission standards apply at all times. 2.) The owner must conduct performance tests to determine compliance with the percent of potential SOx emission rate and the SOx emission rate. 3.) Compliance with the sulfur dioxide standards shall be determined using a 30 day average. 4.) An initial performance test shall be conducted over the first 30 consecutive operating days, for exceptions and specific requirements see §60.45b (f). 5.) Compliance after the initial performance test is required, see §60.45b (f) for specific requirements. 6.) The owner shall use all valid emission data, including valid SOx data collected from periods of startup, shutdown and malfunction to calculate percent reduction and compliance with standards. 7.) During periods of malfunction of the SOx control system when oil is combusted emission data are not used to calculate %Ps or Es.	1.) The NOx emission standards apply at all times 2.) To determine compliance with emission limits for NOx the owner or operator shall conduct the performance tests as required using a continuous system for measuring NOx, for specific requirements see §60.46b (e) (1-5).	1.) The PM emission standards and opacity limits apply at all times except during periods of startup, shutdown and malfunction 2.) To determine compliance for PM the following procedures apply:See §60.46b (d) (1-6) for specific requirements. a.) Method 3B is used for gas analysis when applying Method 5 or 17. b.) Method 5, 5B or 17 shall be used to measure the concentration of PM for specific requirements see §60.46b (d) (2). c.) Method 1 is used to select the sampling site and the number of traverse sampling points. d.) Method 9 is used for determining the opacity of stack emissions
Facility combust coal or oil only	1.) The procedures of Method 19 are used to determine the hourly emission rate and the hourly averages used to compute the 30-day averages are obtained from the CEMS. 2.) The percent of potential sulfur dioxide emission rate (% Ps) emitted to the atmosphere is computed using the following formula: % Ps=100 (1-% Rg/100)(1-% Rf/100) For variables and units see§60.45b (c) (2) (ii)		
Coal or oil combusted with other fuels	1.) The procedures of Method 19 are used to determine the hourly emission rate and the hourly averages used to compute the 30-day averages are obtained from the CEMS. 2.) The percent of potential sulfur dioxide emission rate (% Ps) emitted to the atmosphere is computed using the following formula: % Ps=100 (1-% Rg/100)(1-% Rf/100) For variables and units see§60.45b (c) (2) (ii) 3.) For exceptions to these requirements see §60.45b (c) (3)		

Source	SOx - §60.45b	NOx - §60.46b	PM - §60.46b
Facilities using duct burners in combined cycle systems		Compliance with emission limits is deterrmined by performance testing, see §60.46b (f) for specific requirements	
Facilities that combust alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 percent by weight or less and have a combined capacity factor for the above of 10 percent or less		The facility shall demonstrate the maximum heat input capacity. (see §60.46b (g-h)	
Facilities that have an annual capacity factor for oil of 10% or less	1.) Conduct initial performance tests over 24 consecutive steam generating unit operating hours at full load. 2.) During periods of malfunction or maintenance of SOx control systems, emission data are not used to calculate potential SOx emission rate or the emission rate. The emission data is used to determine compliance with the emission limits.		
Facilities that have an annual capacity factor for coal and oil of 30% or less	Facility shall demonstrate the maximum design capacity of the steam generating unit. For specific requirements see §60.45b (e)		
Facilities that combust very low sulfur oil	Facility is not subject to the compliance and performance testing requirementsof this section if the operator obtains fuel receipts.		

Emission monitoring

Source	SOx - §60.47b	NOx - §60.48b	PM - §60.48b
General	1.) The owner or operator shall install, calibrate, maintain, and operate continuous emission monitoring systems for measuring SOx concentrations and either O2 or CO2 concentrations. 2.) Several alternatives to a CEMS are available see §60.47b (b) (1-4). 3.) Emission data shall be collected for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If the minimum data requirement is not met with a single monitoring system, data may be supplemented with data from other systems at the discretion of the administrator. 4.) The following procedures will be followed for installation, evaluation, and operation of the CEMS. a.) All CEMS shall be operated in accordance with the applicable procedures under performance specifications 1, 2, and 3 (appendix B) b.) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 1 (Appendix F) c.) The span value of the SOx CEMS at the inlet to the SOx control device is 125 percent of the maximum estimated hourly emission rate and the span value of the CEMS at the outlet of the control device is 50 percent of the maximum estimated hourly potential emissions.	1.) The owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring NOx emissions and record the output of the system. 2.) The CEMS shall be operated and data recorded during all periods of operation except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span checks. 3.) The span value for NOx is 1000 PPM for coal combustion . 4.) All span values are rounded to the nearest 500 PPM. 5.) If CEMS for NOx data is not available due to breakdowns, repairs, calibration checks, and span adjustments, emission data will be obtained by using either Method 7, 7A, or other approved monitoring system. 6.) Span values for facilities combusting a combination of fuels are calculated using the equation found in §60.48b (e) (2) 7.) For exceptions to the above requirements based on facility type see §60.48b (g-i)	1.) The owner or operator shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for measuring the opacity of emissions and record the output of the system. 2.) For facilities combusting coal, the span value for a CEMS for measuring opacity shall be between 60 and 80 percent

Subpart Db - Institutional steam generating units

Emission limits

Source	SOx - §60.42b	NOx - §60.44b	PM - §60.43b
General	1.) Compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements are determined on a 30-day rolling average basis. 2.) Compliance with the emission limits or fuel oil sulfur limits is determined on a 24-hour average basis for affected facilities that: a.) have a Federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less b.) combust only very low sulfur oil, and c.) do not combust any other fuel. 3.) Sulfur dioxide emission limits and percent reduction requirements apply at all times, including periods of startup, shutdown, and malfunction. 4.) Reductions in the potential sulfur dioxide emission rate through fuel pretreatment are not credited toward the percent reduction requirement unless: a. Fuel pretreatment results in a 50 percent or greater reduction in potential sulfur dioxide emissions and b. Emissions from the pretreated fuel (without combustion or post combustion sulfur dioxide control) are equal to or less than the emission limits specified. 5.) Percent reduction requirements are not applicable to facilities combusting only very low sulfur oil.	1.) These standards apply at all times including periods of startup, shutdown, or malfunction. 2.) compliance with the emission limits is determined on a 30-day rolling average basis.	1.) The facility may not emit gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. 2.) The particulate matter and opacity standards apply at all times, except during periods of startup, shutdown or malfunction. 3.) The annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum design heat input capacity.
Coal or Oil Combustion	1.) SOx emissions must be reduced by 90 percent from the uncontrolled potential emission rate and the source may not emit more than the emission limit (Es) as calculated by Es=(1.2 * Ha + 0.08 * Hb)/(Ha+Hb), Ha=heat input from coal, Hb=heat input from oil 2.) Facility may combust very low sulfur oil or natural gas when the sulfur dioxide control system is not being operated because of malfunction or maintenance of the sulfur dioxide control system.		
Coal refuse with fluidized bed combustion	1.) SOx emissions must be reduced by 80 percent from the uncontrolled potential emission rate and the source may not emit SOx greater than 1.2 lb/MMBtu heat input 2.) Facility may combust very low sulfur oil or natural gas when the sulfur dioxide control system is not being operated because of malfunction or maintenance of the sulfur dioxide control system.		
Coal or oil combustion, either alone or in combination with any other fuel and using an emerging technology.	1.) SOx emissions must be reduced by 50 percent of the uncontrolled potential emission rate and the source may not emit more than the emission limit (Es) as calculated by: Es=(0.6 * Hc + 0.4 * Hd)/(Hc + Hd), Hc=heat input coal, Hd=heat input from oil 2.) Facility may combust very low sulfur oil or natural gas when the sulfur dioxide control system is not being operated because of malfunction or maintenance of the sulfur dioxide control system.		
Facilities with an annual capacity factor for coal and oil of 30% or less.	The source may not emit SOx greater than 1.2 lb/MMBtu heat input, if facility burns coal or the source may not emit SOx greater than 0.5 lb/MMBtu heat input if the facility burns oil other than very low sulfur oil (<0.5 percent sulfur).		The facility may not emit more than 0.20 lb/MMBtu heat input.
Source	SOx - §60.45b	NOx - §60.46b	PM - §60.46b

Facilities located in a noncontinental area	The source may not emit SOx greater than 1.2 lb/MMBtu heat input, if facility burns coal. or the source may not emit SOx greater than 0.5 lb/MMBtu heat input if the facility burns oil other than very low sulfur oil (<0.5 percent sulfur).		
Facilities combusting in a duct burner as part of a cycle system where 30% of the fuel is from coal or oil and 70% is from exhaust gas.	The source may not emit SOx greater than 1.2 lb/MMBtu heat input, if facility burns coal. or the source may not emit SOx greater than 0.5 lb/MMBtu heat input if the facility burns oil other than very low sulfur oil (<0.5 percent sulfur).		
Facility combusts coal, oil, or natural gas only		Fuel/steam generator type emission limit Natural gas and distillate oil: Low heat release rate.....0.10 lb/MMBtu High heat release rate.....0.20 lb/MMBtu Residual oil: Low heat release rate.....0.30 lb/MMBtu High heat release rate.....0.40 lb/MMBtu Coal: Mass-feeder stoker.....0.50 lb/MMBtu Spread stoker and fluidized bed.....0.60 lb/MMBtu Pulverized coal.....0.70 lb/MMBtu Lignite.....0.60 lb/MMBtu Lignite mined in ND, SD, MT and combusted in a slag tap furnace.....0.80 lb/MMBtu Coal derived synthetic fuel.....0.50 lb/MMBtu Duct burner used in a combined cycle system: Natural gas & distillate oil.....0.20 lb/MMBtu Residual oil.....0.40 lb/MMBtu	
Facilities that combust mixtures of coal, oil, or natural gas		Facility may not emit NOx greater than the limit established by the following formula: En=[(ELgo*Hgo)+(ELro*Hro)+(ELc*Hc)]/(Hgo+Hro+Hc) see §60.44b (b) for variable description and units	
Facilities that combust coal, oil, or natural gas simultaneously with by-product/waste		Facility may not emit NOx greater than the limit established by the following formula: En=[(ELgo*Hgo)+(ELro*Hro)+(ELc*Hc)]/(Hgo+Hro+Hc) see §60.44b (e) for variable description and units	
Facilities that combust coal or oil and have an annual capacity factor for other fuels of 10% or less			Facility may not emit more than 0.05 lb/MMBtu heat input and the source may not emit gases exhibiting a 6 hr opacity factor greater than 20%
Facilities that combust coal and have an annual capacity factor for other fuels greater than 10%			Facility may not emit more than 0.10 lb/MMBtu heat input and the source may not emit gases exhibiting a 6 hr opacity factor greater than 20%
Source	SOx - §60.45b	NOx - §60.46b	PM - §60.46b

Facilities that combust wood, or wood with other fuels, except coal and has an annual capacity factor greater than 30 percent (0.30) for wood.			Facility may not emit greater than 43 ng/J (0.10 lb/million Btu) heat input.
Facilities that combust wood, or wood with other fuels and the facility has an annual capacity factor of 30 percent (0.30) or less for wood.			Facility may not emit greater than 86 ng/J (0.20 lb/million Btu) heat input.
Facilities that combusts only municipal-type solid waste, or If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.			Facility may not emit greater than 43 ng/J (0.10 lb/million Btu) heat input.
Facilities that combust municipal-type solid waste or municipal-type solid waste and other fuels; and has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less.			Facility may not emit greater than 86 ng/J (0.20 lb/million Btu) heat input
Facilities that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal and has an annual capacity factor for natural gass of 10 percent (0.10) or less.		Facility may not emit greater than 130 ng/J (0.30 lb/million Btu) heat input	
Facilities that s combust hazardous waste with natural gas or oil		Facility may petition the administrator within 180 days of startup to establish a NOx emission standard	
Facilities that combust byproduct/waste with either natural gas or oil		Facility may petition the administrator within 180 days of startup to establish a NOx emission standard	

Reporting and record keeping requirements - §60.49b

ALL SOURCES (General)

The owner or operator of each affected facility shall:

1.) Submit notification of the date of initial startup.
2.) Submit to the administrator the performance test and performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specification.
3.) Record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, oil, natural gas, wood, and municipal-type solid waste for each calendar quarter.
4.) For facilities combusting residual oil, maintain records of the nitrogen content of the residual oil combusted.
5.) Maintain records of opacity.
6.) Submit excess emission reports for any calendar quarter during which there are excess emissions.
7.) If no excess, emissions facility must submit reports semiannually stating that no excess emissions have occurred.
8.) Submit the maximum heat input capacity data from the demonstration of maximum heat input capacity.
9.) Maintain all records required for a period of 2 years following the date of such record.

SOx	NOx
The owner or operator of each affected facility subject to SOx standards shall submit to the administrator: 1.) Calendar dates covered in the reporting period 2.) Each 30-day average SOx emission rate 3.) Each 30-day average percent reduction in SOx calculated during the reporting period 4.) Identification of the days that coal or oil was combusted and for which SOx or diluent data have not been obtained for at least 75% of the operating days 5.) Identification of the times when emission data have been excluded from the calculation of emission rates 6.) Identification of "F" factors used in calculations 7.) Identification of times when hourly averages have been obtained based on manual sampling methods 8.) Identification of times when pollutant concentrations have exceeded full span of the CEMS 9.) Description of any modification to the CEMS 10.) Results of daily drift tests 11.) The annual capacity factor for each fuel fired 12.) If the facility combust very low sulfur fuel oil then all of the above apply plus the 24 hour average SOx emission rate 13.) If the minimum amount of data is not obtained during a calendar quarter the following additional information is needed: a.) The number of hourly averages for outlet emission rates and inlet emission rates b.) The standard deviation of hourly averages for outlet and inlet emission rates c.) The lower confidence limits for the mean outlet emission rate and the upper confidence limit for the for the mean inlet emission rate d.) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate.	The owner or operator of each affected facility subject to NOx standards shall submit to the administrator: 1.) A plan that identifies the operating conditions to be monitored and the records to be maintained. This plan shall be submitted for approval within 360 days of the initial startup. 2.) Calendar date 3.) Average hourly NOx emission rate 4.) The 30-day NOx emission rates 5.) Identification of dates that emission standards were exceeded 6.) Identification of dates that which pollutant operating data has not been obtained 7.) Identification of dates when emission data has been excluded from average calculations 8.) Identification of "F" factors used in calculations 9.) Identification of times when pollutant concentrations were greater than full span of the CEMS 10.) Description of any modifications to the CEMS 11.) Results of daily CEMS drift tests 12.) If percent removal efficiency by fuel pretreatment is used to determine overall percent reduction the facility shall submit the following: a.) Indicate what removal efficiency was credited by quarter b.) List the quantity, heat content, and date each pretreated fuel shipment was received during the previous calendar quarter c.) Document the transport of the fuel from the fuel pretreatment to the steam generating unit d.) Provide a signed statement by the operator confirming removal efficiency of the pretreatment