

REGULATION 7.06 Standards of Performance for New Indirect Heat Exchangers

Air Pollution Control District of Jefferson County Jefferson County, Kentucky

Relates to: KRS Chapter 77 Air Pollution Control

Pursuant to: KRS Chapter 77 Air Pollution Control

Necessity and Function: KRS 77.180 provides that the air pollution control board may make and enforce all needful orders, rules, and regulations necessary or proper to accomplish the purposes of KRS Chapter 77. This regulation provides for the control of emissions from new indirect heat exchangers.

SECTION 1 Applicability

This regulation applies to each affected facility commenced after the applicable classification date defined below.

SECTION 2 Definitions

Terms used in this regulation not defined herein shall have the meaning given them in Regulation 1.02.

- 2.1 "Affected facility" means an indirect heat exchanger having input capacity of more than one million BTU per hour.
- 2.2 "Classification date" means:
 - 2.2.1 August 17, 1971 for affected facilities with a capacity of more than 250 million BTU per hour heat input with respect to particulate emissions, sulfur dioxide emissions and, if fuels other than lignite are burned, nitrogen oxide emissions;
 - 2.2.2 April 9, 1972 for affected facilities with a capacity of 250 million BTU per hour heat input or less with respect to particulate emissions and sulfur dioxide emissions; or
 - 2.2.3 December 22, 1976 for affected facilities with a capacity of more than 250 million BTU per input with respect to nitrogen oxides if lignite is the fuel burned.
- 2.3 "Coal" means all solid fuels classified as anthracite, bituminous, sub-bituminous or lignite by ASTM designation D388-66.
- 2.4 "Coal refuse" means waste products of coal mining, cleaning, and coal preparation operations, which contain coal, matrix material, clay, and other materials.
- 2.5 "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.
- 2.6 "Indirect heat exchanger" means any piece of equipment, apparatus or contrivance used for the combustion of fuel in which the energy produced is transferred to its point of usage through a medium that does not come in contact with or add to the products of combustion.
- 2.7 "Wood residue" means bark, sawdust, slabs, chips, shaving, mill trim, and other wood products derived from wood processing and forest management operations.

SECTION 3 Method for Determining Allowable Emission Rates

- 3.1 The total rated heat input capacity of all affected facilities within a source, including those for which an application to construct, modify or reconstruct has been submitted to the District, shall be used as specified in sections 4 and 5 to determine the allowable emission in terms of pounds per million BTU input.
- 3.2 At such times as any affected facility is assigned an allowable emission rate by the District, at no time thereafter shall that rate be changed due to inclusion or shutdown of any affected facility at the source.

SECTION 4 Standard for Particulate Matter

No owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility, particulate matter in excess of that specified below:

- 4.1 For sources having a total heat input capacity as determined by section 3.1 that are:
 - 4.1.1 10 million BTU per hour or less, the standard is 0.56 pounds per million BTU actual heat input;
 - 4.1.2 250 million BTU per hour or more, the standard is 0.10 pounds per million BTU actual heat input;
 - 4.1.3 If the affected facility commenced before the effective date of this regulation, for heat input values between 4.1.1 and 4.1.2 above, the standard in pounds per million BTU actual heat input is equal to 0.9634 times that quantity obtained by raising the total heat input capacity (in millions of BTU per hour) to the -0.2356 power;
 - 4.1.4 If the affected facility commenced on or after the effective date of this regulation, for heat input values between 4.1.1 and 4.1.2 on previous page, the standard in pounds per million BTU actual heat input is equal to 1.919 times that quantity obtained by raising the total heat input capacity (in millions of BTU per hour) to the -0.535 power; or
- 4.2 Emissions which exhibit greater than 20% opacity except:
 - 4.2.1 For indirect heat exchangers with a heat input capacity of less than 250 million BTU/hr, a maximum of 40% opacity shall be permissible for not more than two consecutive minutes in any 60 consecutive minutes;
 - 4.2.2 For indirect heat exchangers with heat input capacity of less than 250 million BTU/hr, a maximum of 40% opacity shall be permissible for not more than six consecutive minutes in any 60 consecutive minutes during cleaning the fire box or blowing soot; or
 - 4.2.3 For emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations.

SECTION 5 Standard for Sulfur Dioxide

No owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility any gases which contain sulfur dioxide in excess of that specified below:

- 5.1 For sources which have a total heat input capacity as determined by section 3.1:
 - 5.1.1 The standard is 1.0 pound per million BTU actual heat input for combustion of liquid and gaseous fuels if the source has a total heat input capacity of 145 million BTU per hour or less. The standard is four pounds per million BTU actual heat input for combustion of solid fuels if the source has a total heat input capacity of ten million BTU per hour or less;
 - 5.1.2 If the source has a total heat input capacity of 250 million BTU per hour or more, the standard is 0.8 pound per million BTU actual heat input for combustion of liquid and gaseous fuels and 1.2 pounds per million BTU actual heat input for combustion of solid fuels;
 - 5.1.3 For heat input values between 5.1.1 and 5.1.2 above, the standard in pounds per million BTU actual heat input is equal to:
 - 5.1.3.1 For combustion of liquid and gaseous fuels, 7.7223 times that quantity obtained by raising the total heat input capacity (in millions of BTU per hour) to the -0.4106 power;
 - 5.1.3.2 For combustion of solid fuels, 9.46 times that quantity obtained by raising the total heat input capacity (in millions of BTU per hour) to the -0.3740 power.
- 5.2 When different fuels are burned simultaneously in any combustion, the applicable standard shall be determined by proration using the equation in Appendix A.
- 5.3 Compliance shall be based on the total heat input from all fuels burned, including gaseous fuels.

SECTION 6 Standard for Nitrogen Oxides

- 6.1 No owner or operator of an affected facility with a heat input capacity of 250 million BTU per hour or more shall cause to be discharged into the atmosphere any gases which contain nitrogen oxides expressed as nitrogen dioxide in excess of:
 - 6.1.1 0.20 lb per million BTU heat input (0.36 g per million cal) derived from gaseous fuel;
 - 6.1.2 0.30 lb per million BTU heat input (0.54 g per million cal) derived from liquid fuel;
 - 6.1.3 0.70 lb per million BTU heat input (1.26 g per million cal) derived from solid fuel (except lignite);
 - 6.1.4 0.60 lb per million BTU heat input (1.08 g per million cal) derived from lignite fuel.
- 6.2 When different fuels are burned simultaneously in any combination, the applicable standard shall be determined by proration using the equation in Appendix B.

SECTION 7 Emission and Fuel Monitoring

This section applies to any affected facility of more than 250 million BTU per hour rated heat input capacity.

- 7.1 Each owner or operator shall install, calibrate, maintain, and operate CEMSs for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions and either oxygen or carbon dioxide except as provided in section 7.2.
- 7.2 Certain of the CEMS requirements under section 7.1 do not apply to owners or operators under the following conditions:
 - 7.2.1 For an indirect heat exchanger that burns only gaseous fuel, CEMSs for measuring the opacity of emissions are not required;
 - 7.2.2 For an indirect heat exchanger that burns only natural gas, CEMSs for measuring sulfur dioxide emissions are not required;
 - 7.2.3 Notwithstanding Regulation 7.01 section 6.2, installation of a CEMS for nitrogen oxides may be delayed until after the initial performance tests under Regulation 7.01 section 4 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70% of the applicable standards in section 6, a CEMS for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70% of the applicable standard, the owner or operator shall install a CEMS for nitrogen oxides within one year after the date of the initial performance tests under Regulation 7.01 section 4 and comply with all other applicable monitoring requirements under these regulations.
 - 7.2.4 If an owner or operator does not install any CEMSs for sulfur oxides and nitrogen oxides, as provided under sections 7.2.1 and 7.2.3 or sections 7.2.2 and 7.2.3, a CEMS for measuring either oxygen or carbon dioxide is not required.
 - 7.2.5 For an indirect heat exchanger that does not use a flue gas desulfurization device, a CEMS for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling & analysis.
- 7.3 For performance evaluations under Regulation 6.01 section 6.3 and calibration checks under Regulation 7.01 section 6.4, the following procedures shall be used:
 - 7.3.1 Reference Method 6 or 7, as applicable, shall be used for conducting performance evaluations of sulfur dioxide and nitrogen oxides CEMSs;
 - 7.3.2 Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of 40 CFR Part 60 Appendix B;
 - 7.3.3 For affected facilities burning fossil fuel, the span value for a CEMS measuring the opacity of emissions shall be 80%, 90%, or 100% and for a CEMS measuring sulfur oxides or nitrogen oxides the span value shall be determined as shown in Appendix C;
 - 7.3.4 All span values computed under section 7.3.3 for burning combinations of fuels shall be rounded to the nearest 500 ppm;
 - 7.3.5 For an indirect heat exchanger that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMSs shall be subject to the District's approval.
- 7.4 A CEMS for measuring either oxygen or carbon dioxide in the flue gases shall be installed, calibrated, maintained and operated by the owner or operator.

7.5 For any CEMS installed under section 7.4, the following conversion procedure shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million BTU);

7.5.1 When a CEMS 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 District shall be when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = \frac{20.9CF}{20.9 - \% \text{ oxygen}}$$

where:

E, C, F and % oxygen are determined under section 7.6.

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

$$E = \frac{100 C F c}{\% \text{ carbon dioxide}}$$

where:

E, C, Fc and % carbon dioxide are determined under section 7.6.

7.6 The values used in the equations in sections 7.5.1 and 7.5.2 are derived as follows:

7.6.1 E = Pollutant emission, g/million cal (lb/million BTU).

7.6.2 C = Pollutant concentration, g/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by .0000415 M g/dscm per ppm (2.59 times ten raised to the minus nine power times 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.

7.6.3 F, Fc = 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 (Fc), respectively, as follows:

7.6.3.1 For anthracite coal as classified according to ASTM D388-66(72), F = 1.139 dscm/million cal (10140 dscf/million BTU) and Fc = 0.222 scm CO₂/million cal (1980 scf CO₂/million BTU).

7.6.3.2 For sub-bituminous and bituminous coal as classified according to ASTM-D388-66 (72), F = 1.103 dscm/million cal (9820 dscf.million BTU) and Fc = 0.203 scm CO₂/million cal (1810 scf CO₂/million BTU).

- 7.6.3.3 For liquid fossil fuels including crude, residual, and distillate oils, $F = 9220$ dscf/million BTU and $F_c = 1430$ scf CO₂/million BTU.
- 7.6.3.4 For gaseous fossil fuels, $F = 0.982$ dscm/million cal (8740dscg/million BTU). For natural gas, propane and butane fuels, $F_c = 0.117$ scm CO₂/million cal (1040 scf CO₂/million BTU) for natural gas; 0.135 scm CO₂/million cal (1200 scf CO₂/million BTU) for propane; and 0.142 scm CO₂/million cal (1260 scf CO₂/million BTU) for butane.
- 7.6.3.5 For bark, $F = 0.450$ dscm/million cal (9575 dscf/million BTU) and $F_c = 0.091$ scm CO₂/million BTU. For wood residue other than bark, $F = 0.434$ dscm/million cal (9233 dscf/million BTU) and $F_c = 0.086$ scm CO₂/million cal (1842 scf CO₂/million BTU).
- 7.6.4 The owner or operator may use the equation given in Appendix D to determine an F factor (dscm/million cal, or dscf/million BTU) on a dry basis (if it is desired to calculate F on a wet basis, consult with the District or Fc factor scf of the F or Fc factors specified in section 7.6.3.
- 7.6.4.1 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 ASTM method D3178-73 or D3176-74 (solid fuels) or computed from results using ASTM methods D1137-53(75), D1945-64(73), D1946-67(72) (gaseous fuels) as applicable.
- 7.6.4.2 GCV is the gross calorific value (cal/g, BTU/lb) of the fuel combusted determined by ASTM test methods D2015- 66(72) for solid fuels and D1826-64(70) for gaseous fuels as applicable.
- 7.6.5 For affected facilities firing combinations of fuels, the For Fc factors determined by sections 7.6.3 and 7.6.4 shall be prorated in accordance with applicable formula as given in Appendix E.
- 7.7 For the purpose of reports required under Regulation 7.01 section 5.3, periods of excess emissions that shall be reported are defined as follows:

- 7.7.1 Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20% opacity, except that one six-minute average per hour of up to 27% opacity need not be reported.
- 7.7.2 Sulfur dioxide. Excess emissions for affected facilities are defined as 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 section 5.
- 7.7.3 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 section 6.
- 7.8 The District may require for any indirect heat exchanger unit of 250 million BTU per hour heat input or less any or all of the emission and fuel monitoring required by this section.

SECTION 8 Test Methods and Procedures

- 8.1 The reference methods in 40 CFR Part 60 Appendix A, except as provided in Regulation 1.04, shall be used to determine compliance with the standards prescribed in sections 4, 5, and 6 as follows:
 - 8.1.1 Method 1 for selection of sampling site and sample traverses;
 - 8.1.2 Method 3 for gas analysis to be used when applying Reference Methods 5, 6, and 7;
 - 8.1.3 Method 5 for concentration of particulate matter and the associated moisture content;
 - 8.1.4 Method 6 for concentration of sulfur dioxide;
 - 8.1.5 Method 7 for concentration of nitrogen oxides.
- 8.2 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 process variables or other factors, may be approved by the District. The probe and filter holder heating systems in the sampling train shall be set to provide a gas temperature no greater than 160 °C (320 °F).
- 8.3 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 constant rate of 1 liter/min, approximately.
- 8.4 For Method 6, minimum sampling time shall be 20 minutes and the minimum sampling volume shall be 0.02 dscm (0.71 dscf) for each sample. The arithmetic mean of 2 samples shall constitute one run. Samples shall be taken at approximately 30 minute intervals.
- 8.5 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.
- 8.6 For each run using the methods in sections 8.1.1, 8.1.2, and 8.1.3, the emissions expressed in g/million cal (lb/million BTU) shall be determined by the following procedure:

$$E = \frac{20.9CF}{20.9 - \% \text{ oxygen}}$$

where

E = pollutant emission g/million cal (lb/million BTU).

C = pollutant concentration, g/dscm (lb/dscf), determined by Method 5, 6, or 7.

F = a factor as determined in sections 8.6.3, 8.6.4, or 8.6.5 of section 7.

% oxygen = 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:

- 8.6.1 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. For Method 7, the oxygen sample shall be obtained using the grab sampling and analysis procedures of Method 3.
- 8.6.2 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 section 8.2. Method 1 shall be used for selection of the number of traverse points except that no more than 12 sample points are required.
- 8.7 When combination of fossil fuels are fired, the heat input, expressed in cal/hr (BTU/hr), shall be determined during each testing period by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned. Gross caloric value shall be determined in accordance with ASTM methods D2015-66(72) (solid fuels) D240-76 (liquid fuels), or D1826-64(70) (gaseous fuels) as applicable. The rate of fuels burned during each testing period shall be determined by suitable methods and shall be confirmed by a material balance over the steam generation system.

Adopted v1/7-14-76; effective 9-1-76; amended v2/4-21-82.

Appendix A to Regulation 7.06

Determination of Allowable Sulfur Dioxide Emissions

Allowable sulfur dioxide emissions in pounds per million BTU per hour heat input =

$$\frac{ya + zb}{y + z}$$

where:

- y = the percent of total heat input derived from liquid or gaseous fuel.
 - a = the allowable sulfur dioxide emission in pounds per million BTU heat input derived from liquid or gaseous fuel.
 - z = the percent of total heat input derived from solid fuel.
 - b = the allowable sulfur dioxide emission in pounds per million BTU heat input derived from solid fuel.
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Appendix B to Regulation 7.06

Determination of Allowable Nitrogen Dioxide Emissions

Allowable nitrogen dioxide emissions in pounds per million BTU/hour heat input =

$$\frac{0.6w + 0.2x + 0.3y + 0.7z}{w + x + y + z}$$

where:

- w = the percent of total heat input derived from lignite.
- x = the percent of total heat input derived from gaseous fuel.
- y = the percent of total heat input derived from liquid fuel.
- z = the percent of total heat input derived from solid fuel (except lignite).

Appendix C to Regulation 7.06

**Determination of Span Value
(in parts per million)**

Fossil Fuel	Span Value for Sulfur Dioxide	Span Value for Nitrogen Oxides
Gas	Not applicable	500
Liquid	1,000	500
Solid	1,500	500
Combinations	$1,000y + 1,500z$	$500(x+y) + 1,000z$

where:

- x = the fraction of total heat input derived from gaseous fossil fuel.
- y = the fraction of total heat input derived from liquid fossil fuel.
- z = the fraction of total heat input derived from solid fossil fuel.

Appendix D to Regulation 7.06

Determination of F or Fc Factor

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

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

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

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

where:

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 ASTM method D3178-73 or D3176-74 (solid fuels) or computed from results using ASTM methods D1137-53(75), D19545-64(73), or D1946-67(72) (gaseous fuels) as applicable.

GCV is the gross calorific value (cal/g, BTU/lb) of the fuel combusted, determined by ASTM test method D2015-66(72) for solid fuels or D1826-64(70) for gaseous fuels as applicable.

Appendix E to Regulation 7.06

Determination of F or Fc Factor for Firing Combinations

$$F = xF_1 + yF_2 + zF_3$$

where:

- x, y, z = the fraction of total heat input derived from gaseous, liquid, and solid fuel, respectively.
F₁, F₂, F₃ = the value of F for gaseous, liquid, and solid fuels respectively under sections 7.6.3 and 7.6.4.

$$Fc = \sum_{i=1}^n x_i (Fc)_i$$

where:

- X_i = the fraction of total heat input derived from each type fuel (e.g., natural gas, butane, crude oil, bituminous coal, etc.)
(Fc)_i = the applicable Fc factor for each fuel type determined in accordance with sections 7.6.3 and 7.6.4.