VENTURA COUNTY AIR POLLUTION CONTROL DISTRICT

RULE 74.15.1 - BOILERS, STEAM GENERATORS, AND PROCESS HEATERS

(Adopted 5/11/93, Revised 6/13/95, 6/13/00, 9/11/12, 6/23/15)

A. Applicability

The provisions of this rule apply to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a rated heat input capacity equal to or greater than 1 million BTU per hour and less than 5 million BTU per hour. Both stationary and portable process heaters are subject to this rule. Applicable gaseous fuels include natural gas, landfill gas, biogas, liquefied petroleum gas (LPG), and produced oilfield gas.

B. Requirements

1. No person shall allow the discharge into the atmosphere, from any boiler, steam generator, or process heater with an annual heat input rate of equal to or greater than 1.8×10^9 BTU, oxides of nitrogen (NOx) emissions in excess of 30 parts per million volume (ppmv). Carbon monoxide (CO) emissions from units subject to this rule shall not exceed 400 ppmv.

2. **Emission Limits for New and Replacement Boilers and Steam Generators and Process Heaters:**

   a. No person shall allow the discharge into the atmosphere, from any new or replacement natural gas-fired boiler, steam generator, or process heater with a rated heat input capacity of equal to or greater than 1 million BTU/hr and less than or equal to 2 million BTU/hr, oxides of nitrogen emissions in excess of 20 ppmv or 0.025 lbs/MMBTU heat input. Carbon monoxide emissions shall not exceed 400 ppmv. In addition prior to installation, each device shall be certified by the South Coast Air Quality Management District in accordance with the requirements of SCAQMD Rule 1146.2, adopted May 5, 2006.

   b. After January 1, 2016, no person shall allow the discharge into the atmosphere, from any **new or replacement** boiler, steam generator, or process heater fired with a rated heat input capacity of greater than 2 million BTU/hr and less than 5 million BTU/hr oxides of nitrogen emissions in excess of the following limits:

CATEGORY	LIMITS
Units fired on Natural Gas- Atmospheric	12 ppm or 0.015 lbs/MMBTU heat input
Units fired on Natural Gas- Pressurized	9 ppm or 0.011 lbs/MMBTU heat input
Units fired on Landfill Gas	25 ppm or 0.031 lbs/MMBTU heat input
Units fired on Biogas	15 ppm or 0.019 lbs/MMBTU heat input
Units fired on Liquefied Petroleum Gas	20 ppm or 0.025 lbs/MMBTU heat input
Units fired on Produced Oilfield Gas - Atmospheric	15 ppm or 0.019 lbs/MMBTU heat input
Units fired on Produced Oilfield Gas – Pressurized	12 ppm or 0.015 lbs/MMBTU heat input

Carbon monoxide emissions shall not exceed 400 ppmv or 0.30 lbs/MMBTU.

3. Any boiler, steam generator, or process heater with an annual heat input rate of equal to or greater than 0.3×10^9 BTU and less than 1.8×10^9 BTU (less than 2.8×10^9 BTU for portable oil well dewaxing process heaters) shall comply with one of the following requirements:
   a. The unit shall be tuned every 6 months or after 750 hours of operation since the previous tune-up, whichever occurs last, but in no case less than once per calendar year. The unit shall be tuned in accordance with the procedure described in Attachment 1 for forced draft-fired equipment or Attachment 2 for natural draft-fired equipment; or

   b. The unit shall comply with the emission and testing requirements of Subsection B.4.

4. Test Requirements

   a. Units with a rated heat input capacity greater than 2 million BTU/hr, and subject to the provisions of Subsection B.1, shall test for compliance upon initial installation and then not less than once every 24 months.

   b. Units with a rated heat input capacity of greater than 2 million BTU/hr, and subject to the provisions of Subsection B.2.b shall test for compliance upon initial installation and then not less than once every 48 months.

   c. Units with a rated heat input capacity of less than or equal to 2 million BTU/hr, and subject to the provisions of Subsection B.1 or B.2.a, shall test for compliance upon initial installation and then not less than once every 48 months. The first source test on this test schedule shall be 48 months after the last source test conducted prior to September 11, 2012.

   d. All units subject to emission limits shall perform an annual screening analysis of NOx and CO emissions unless a source test specified in either Subsection B.4.a, B.4.b, or B.4.c is required that year. The deadline for performing this annual screening is no later than the yearly anniversary date of the last source test. The operator shall notify the APCD by telephone, fax, or email, 24 hours prior to any screening analysis.

C. Exemptions

1. The provisions of Section B of this rule shall not apply to any unit operated on alternate fuel under the following conditions:

a. Alternate fuel use is required due to the curtailment of natural gas service to the individual unit by the natural gas supplier. Alternate fuel use in this case shall not exceed the period of natural gas curtailment.

b. Alternate fuel use is required to maintain the alternate fuel system. Alternate fuel use in this case shall not exceed 50 hours per year.

2. The emission limits in Subsection B.1 shall not apply to any portable oil well dewaxing process heater if the annual heat input rate is less than 2.8 x 10^9 BTU.

D. Recordkeeping Requirements

1. Any person owning and/or operating a boiler, steam generator, or process heater with an annual heat input rate of less than 2.8 x 10^9 BTU and not subject to the requirements of Subsection B.1 shall install a totalizing fuel meter for each applicable unit and for each fuel. Meters shall be accurate to ± one (1) percent, as certified by the manufacturer in writing. Fuel consumption for each unit shall be compiled monthly into a rolling twelve (12) calendar month report.

2. Any person subject to the provisions of Subsection B.3.a shall submit a report to the Air Pollution Control Officer (APCO) within forty-five (45) days after achieving first compliance with Subsection B.3.a. Reports shall continue to be submitted every twelve (12) months. The report shall verify that each tune-up has been performed and the results were satisfactory. The report shall contain all information and or documentation that the APCO may determine, in writing, to be necessary.

3. Any person subject to the provisions of Subsection B.4.d shall submit a report to the APCO within forty-five (45) days after first achieving compliance with the subsection. Reports shall continue to be submitted every twelve (12) months. The report shall contain all information and or documentation that the APCO may determine, in writing, to be necessary. Any person subject to the provisions of Subsection B.4.d, shall record the results of all screenings in an annual test log, and this log shall be made available to APCD personnel upon request. This log shall indicate the date of the screening, the NOx and CO emissions measured at 3% Oxygen (calculated as NO_2), the applicable NOx and CO limits for the unit, and any action taken, if applicable.

4. Any person utilizing alternate fuel, pursuant to the provisions of Subsection C.1 of this rule, shall maintain daily records of each occurrence. Each record shall include the type of fuel, the quantity of fuel, and the duration of the occurrence.

5. All records required by Subsection D shall be maintained for a period of four (4) years and shall be available for inspection by the APCO upon request.

E. Test Methods

1. Compliance with the emission requirements in Section B shall be determined using ARB Method 100 for Oxides of Nitrogen, Carbon Monoxide, and Stack Gas Oxygen. An alternative procedure for determining emission compliance in units of lb/MMBTU heat input shall be determined using the South Coast AQMD "Compliance Protocol for the Measurement of Nitrogen Dioxide, Carbon Monoxide, and Oxygen From Sources Subject to SCAQMD Rules 1146 and 1146.1" dated March 10, 2009.

2. Emission tests resulting in compliance determinations for the requirements of Subsection B.1 or B.2 shall be conducted on units in "As-found" operating condition.

3. The NOx parts per million emission limitation specified in Subsection B.1 and B.2 is expressed as nitrogen dioxide. The limitations for both NOx and CO are referenced at three (3) percent volume stack gas oxygen on a dry basis averaged over 15 consecutive minutes.

4. Screening analyses required pursuant to Subsection B.4.d shall be performed using a portable analyzer calibrated, maintained, and operated in accordance with the manufacturer's specifications or as approved in writing by the APCO. Portable analyzer operators shall undergo training, on the operation and maintenance of the analyzer.

F. Violations

1. Failure to comply with any provision of this rule shall constitute a violation of this rule.

2. Any unit subject to the provisions of Subsection B.3 shall comply with the provisions of Subsection B.1 if the unit operates during any rolling twelve (12) month period at a total annual heat input rate greater than the applicable annual heat input rate specified in Subsection B.3.

3. Any unit previously operating at an annual heat input rate of less than 0.3×10^9 BTU shall comply with the applicable provisions of Subsection B.1 or Subsection B.3 if the unit operates during any rolling twelve (12) month period at a total annual heat input rate greater than 0.3×10^9 BTU.

4. An applicable unit shall be in violation if, according to a screening analysis, it is operated out-of-compliance with the requirements of either Subsection B.1 or B.2 as follows. All out-of-compliance screening analyses shall be reported to the District within seven (7) calendar days. The unit shall be corrected and a second screening analysis or source test shall be performed within fourteen (14) calendar

days of the initial screening analysis. The results of the second analysis shall be reported to the District within seven (7) days. If the unit remains out-of-compliance, a violation has occurred.

G. Definitions

1. "Alternate Fuel": Any fuel that is permitted to be used due to natural gas curtailment by the natural gas supplier because of limited availability.

2. “Atmospheric Unit”: Any natural gas or produced oilfield gas fired unit with a non-sealed combustion chamber in which natural draft is used to exhaust combustion gases.

3 "Annual Heat Input": The actual amount of heat released by fuels burned in a unit during a twelve (12) calendar month rolling period, based on the fuel's higher heating value. The annual heat input shall be calculated as the sum of the previous 12 monthly fuel use rates multiplied by the fuel's higher heating value.

4. “Biogas”: A gaseous mixture of methane and carbon dioxide produced by the bacterial decomposition of organic waste and used as a fuel, including, but not limited to, digester gas.

5 "Boiler or Steam Generator": Any external combustion equipment fired with liquid and/or gaseous fuel and used to produce steam or to heat water. Boiler or Steam Generator does not include any unfired waste heat recovery boiler that is used to recover sensible heat from the exhaust of any combustion equipment.

6. “Landfill Gas”: Any gas derived through any biological process from the decomposition of waste buried within a waste disposal site.

7. “Liquefied Petroleum Gas (LPG)”: An organic compound having a vapor pressure not exceeding that allowed for commercial propane that is composed predominantly of the following hydrocarbons, either by themselves or as mixtures: propane, propylene, butane, and to a lesser extent butylenes, and that is stored and transported under pressure in a liquid state.

8. “Natural Gas”: Any mixture of gaseous hydrocarbons containing at least 80 percent methane by volume, as determined using Standard Method ASTM D1945-03(2010) or later revision.

9. "New or Replacement Boiler, Steam Generator, or Process Heater": Any applicable unit sold, offered for sale, or installed after January 1, 2013, pursuant to Subsection B.2.a or after January 1, 2016, pursuant to Subsection B.2.b.

10. “Open Heated Tank”: Any non-pressurized self-heated tank that may include a cover or doors that can be opened or detached to put in or remove parts,

components or other material for processing in the tank. Tanks heated solely by an electric heater, boiler, thermal fluid heater, or heat recovered from another process using heat exchangers are excluded from this definition.

11. “Portable Oil Well Dewaxing Process Heater”: Any portable process heater mounted on a truck or trailer that is used to heat and circulate fluid (usually crude oil) around oil well production tubing or oil flow lines to remove paraffin wax (a natural occurring constituent of crude oil) to prevent loss of oil production caused by wax plugging of the unit.

12. “Pressurized Unit”: Any unit that does not meet the criteria needed to qualify as an atmospheric unit.

13. "Process Heater": Any external combustion equipment fired with liquid and/or gaseous fuel and which transfers heat from combustion gases to water or process streams. For the purpose of rule applicability, process heater does not include any of the following combustion sources:
    a. Kiln, oven, open heated tank, dehydrator, dryer, crematory, incinerator, calciner, cooker, roaster, or furnace.,
    b. Unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment,
    c. Fuel-fired degreasing or metal finishing equipment including parts washers and metal heat treating or metal furnaces,
    d. Afterburner, vapor incinerator, or thermal or catalytic oxidizers used as an emission control device.
    e. Glass melting furnace,
    f. Tenter frame, fabric or carpet dryer.

14. “Produced Oilfield Gas”: Any mixture of gaseous hydrocarbons produced in the oil field containing less than 80 percent methane by volume, as determined using Standard Method ASTM D1945-03(2010) or later revision.

15. "Rated Heat Input Capacity": The heat input capacity specified on the nameplate of the combustion unit. If the combustion unit has been altered or modified such that its maximum heat input is different than the heat input capacity specified on the nameplate, the new maximum heat input shall be considered as the rated heat input capacity. This alteration or modification can be through either burner alteration or modification or installation of a fixed orifice. The new maximum heat input must be certified, in writing, by the manufacturer or installer and engineering calculations supporting the new maximum heat input rating must be submitted to the APCO.

16. “Tenter Frame Dryer”: Any cloth dryer that hold the edges of the material as it is dried in order to control shrinkage.

17. "Therm": 100,000 BTU.

18. "Unit": Any boiler, steam generator, or process heater as defined in Subsections G.5, G.9, and G.13 of this rule.

ATTACHMENT 1

Equipment Tuning Procedure
for Forced Draft-fired Equipment[1]

Nothing in this Equipment Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate the unit at the firing rate most typical of normal operation. If the unit experiences significant load variations during normal operation, operate it at its average firing rate.

2. At this firing rate, record stack gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke-spot number[2] (for liquid fuels), and observe flame conditions after unit operation stabilizes at the firing rate selected. If the excess oxygen in the stack gas is at the lower end of the range of typical minimum values[3], and if the CO emissions are low and there is not smoke, the unit is probably operating at near optimum efficiency - at this particular firing rate. However, complete the remaining portion of this procedure to determine whether still lower oxygen levels are practical.

3. Increase combustion air flow to the furnace until stack gas oxygen levels increase by one to two percent over the level measured in Step 2. As in Step 2, record the stack gas temperature, CO concentration (for gaseous fuels) or smoke-spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after boiler operation stabilizes.

4. Decrease combustion air flow until the stack gas oxygen concentration is at the level measured in Step 2. From this level gradually reduce the combustion air flow, in small increments. After each increment, record

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[1]. This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for the EPA.

[2]. The smoke-spot number can be determined with ASTM Test Method D-2156 or with the Bacharach method.

[3]. Typical minimum oxygen levels for boilers at high firing rates are:

1. For natural gas: 0.5% - 3%
2. For liquid fuels: 2% - 4%

the stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also observe the flame and record any changes in its condition.

5. Continue to reduce combustion air flow stepwise, until one of these limits in reached:

   a. Unacceptable flame conditions - such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability.

   b. Stack gas CO concentrations greater than 400 ppm.

   c. Smoking at the stack.

   d. Equipment-related limitations - such as low windbox/furnace pressure differential, built in air-flow limits, etc.

6. Develop an 0_2/CO curve (for gaseous fuels) or 0_2/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 using the excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.

7. From the curves prepared in Step 6, find the stack gas oxygen levels where the CO emissions or smoke-spot number equal the following values:

Fuel	Measurement	Value
Gaseous	CO Emissions	400 ppm
#1 & #2 oils	smoke-spot number	number 1
#4 oil	smoke-spot number	number 2
#5 oil	smoke-spot number	number 3
Other oils	smoke-spot number	number 4

   The above conditions are referred to as CO or smoke threshold, or as the minimum excess oxygen level.

   Compare this minimum value of excess oxygen to the expected value provided by the combustion unit manufacturer. If the minimum level found is substantially higher than the value provided by the combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mixing, thereby allowing operation with less air.

8. Add 0.5 to 2.0 percent to the minimum excess oxygen level found in Step 7 and reset burner controls to operate automatically at this higher stack gas oxygen level. This

margin above the minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or play in automatic controls.

9. If the load of the combustion unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent the upper and lower limits of the range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish the optimum excess oxygen level at all firing rates. If this is the case, choose the burner control settings that give best performance over the range of firing rates. If one firing rate predominates, settings should optimize conditions at that rate.

10. Verify that the new settings can accommodate the sudden changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If any of the conditions in Step 5 result, reset the combustion controls to provide a slightly higher level of excess oxygen at the affect firing rates. Next, verify these new settings in a similar fashion. Then make sure that the final control settings are recorded at steady-state operating conditions for future reference.

Figure 1

Oxygen/CO Characteristic Curve

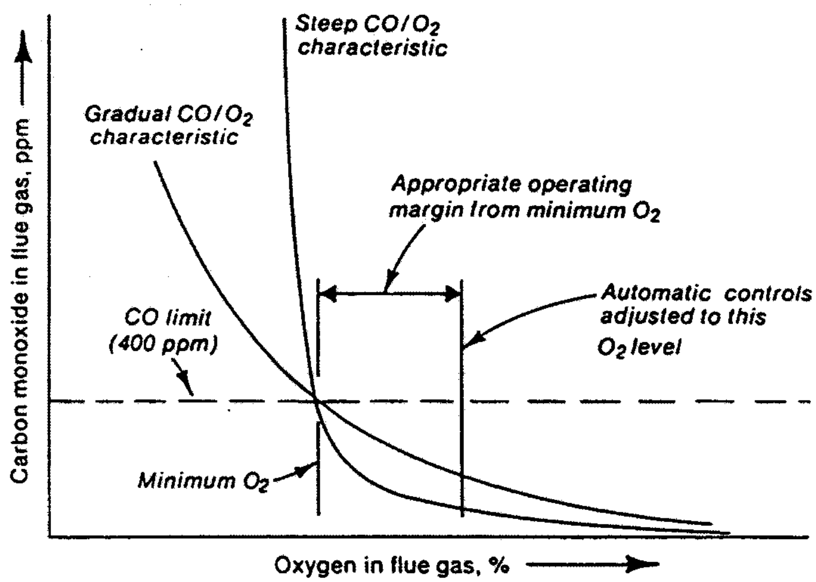
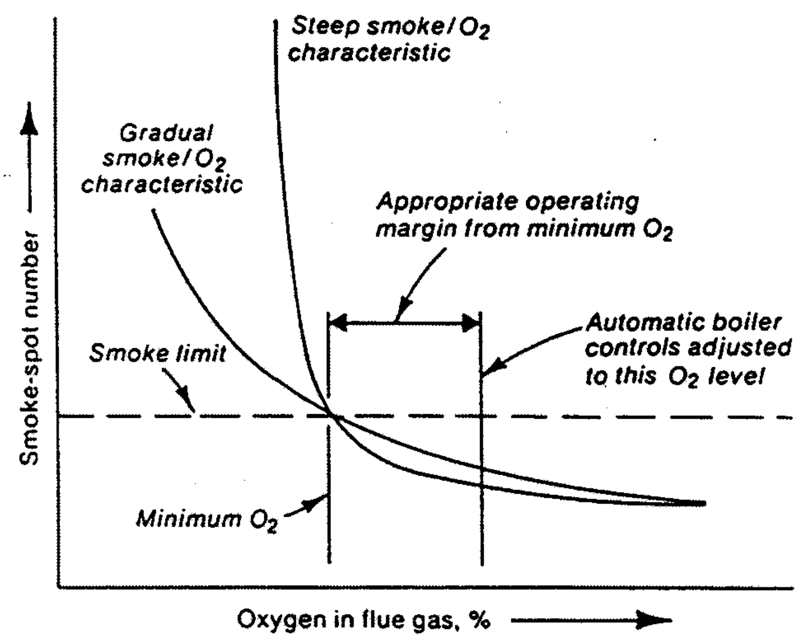


Figure 2

Oxygen/Smoke Characteristic Curve



ATTACHMENT 2

Equipment Tuning Procedure
for Natural Draft-Fired Equipment

Nothing in this Equipment Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division). the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements. Steps in the Procedure not applicable to specific units may be omitted.

1. Preliminary Analysis

   a. Verify that the boiler, steam generator, or process heater (unit) is operating at the lowest pressure or temperature that will satisfy load demand. This pressure or temperature will be used as a basis for comparative combustion analysis before and after tune-up.

   b. Verify that the unit operates for the minimum number of hours and days necessary to perform the work required.

   c. Verify that the size of air supply openings is in compliance with applicable codes and regulations. Air supply openings must be fully open when the burner is firing and air flow must be unrestricted.

   d. Verify that the vent is in good condition, properly sized and free from obstruction.

   e. Perform a combustion analysis (CO, O_2, etc.) at both high and low fire, if possible. Record all data, as well as the following:

      (1) Inlet fuel pressure at burner at high and low firing rates.
      (2) Pressure above draft hood or barometric damper at high, medium and low firing rates.
      (3) Steam pressure, water temperature, or process fluid pressure or temperature entering and leaving the unit.
      (4) Inlet fuel use rate if meter is available.

2. Checks & Corrections

   a. Clean all dirty burners or burner orifices. Verify that fuel filters and moisture traps are in place, clean, and operating properly. Confirm proper location and orientation of burner diffuser spuds, gas canes, etc. Replace or repair damaged or missing burner parts.

b. Remove external and internal sediment and scale from heating surfaces.

c. Verify that the necessary water or process fluid treatment is being used. Confirm flushing and/or blowdown schedule.

d. Repair all leaks. In addition to the high-pressure lines, check the blow-off, drain, safety valve, bypass lines and, if used, the feed pump.

3. Safety Checks

a. Test primary and secondary low water level controls.

b. Check operating and limit pressure and temperature controls.

c. Check pilot safety shut off operation.

d. Check safety valve pressure setting and verify that the setting is consistent with unit load requirements.

e. Check limit safety control and spill switch.

4. Adjustments

Perform the following checks and adjustments on a warm unit at high fire:

a. Adjust unit to fire at the maximum inlet fuel use rate: record fuel manifold pressure.

b. Adjust draft and/or fuel pressure to obtain acceptable, clean combustion at both high, medium and low firing rates. The carbon monoxide (CO) value should not exceed 400 parts per million (PPM) at 3% O_2.

Verify that unit light-offs are smooth and safe. Perform a reduced fuel pressure test at both high and low firing rates in accordance with the manufacturers instructions.

c. Check and adjust the modulation controller. Verify proper, efficient and clean combustion through the range of firing rates.

When optimum performance has been achieved, record all data.

5. Final Test

Perform a final combustion analysis on the warm unit at high, medium and low firing rates, if possible. Record data obtained from combustion analysis, as well as the following:

a. Inlet fuel pressure at burner at high and low firing rates.

b. Pressure above draft hood or barometric damper at high, medium and low firing rates.

c. Steam pressure, water temperature, or process fluid pressure or temperature entering and leaving the unit.

d. Inlet fuel use rate if meter is available.