BOILER EMISSION GUIDE

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BOILER EMISSIONS REFERENCE GUIDE
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INTRODUCTION

Since the beginning of time, mankind, flora, and fauna have been sustained by sunlight, fresh water, and clean air. But fly over many regions of the country today, and one will see our cities and mountains shrouded in a dull haze of pollutants. Look upon the horizon and see the sun's rays reflect a kaleidoscope of colors — grey for lead, yellow for sulphur, brown for nitrogen oxides.

From the Appalachian Mountains, where brown tree tops are brittle and burnt from acid rain, to the Great Lakes, where shorelines all too often appear rimmed by murky mist, to the San Gabriel Mountains, where a natural inversion of the atmosphere presses a blanket of smog upon Southern California, we can't escape the damage.

Carbon Monoxide, lead, nitrogen oxides, ozone, particulate matter, and sulfur, are now cited as the most insidious of pollutants. They are proven to contribute to respiratory illnesses in humans, damage to the environment and buildings and, ultimately, lead to higher costs for health care and environmental cleanup.

Over the past several decades, the culprit pollutants spewed into our environment at increasing rates. Thus, in the 1980s, alarmed environmental activists and coalitions began to pressure Congress for stiffer air pollution control regulations. The result: in 1990, Congress passed its most comprehensive piece of environmental legislation, the Clean Air Act Amendments (CAAA).

The Boiler Emissions Reference Guide is a multi-purpose tool, which is intended to give you a clearer understanding of how industrial boilers fit into the clean air equation.

In the first part, the guide discusses how federal and state actions are driving the air cleanup. It discusses air quality standards and areas of attainment and nonattainment for the pollutants. It describes how the government has set up emission limits for industrial boilers and other equipment. And, it looks at permitting, emission limitations, and BACT, RACT, LAER — the alphabet of control techniques.

The second part of the guide examines the six major pollutants in detail and discusses various control techniques. Emphasis is placed on combustion control for industrial boilers and how to choose the best technology.

The guide concludes with special appendices, which provide fingertip information — a must when dealing with a problem as complex as air pollution.

A word of caution...

The information conveyed in the appendix and figures 2, 3, 4 & 5 are dynamic and may change based on the latest requirements issued by the EPA. Visiting an EPA site such as <epa.gov> will assist you in keeping abreast of the latest requirements.

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REGULATIONS

Air pollution regulations are enacted at the federal level or at the state and local level. Federal regulations, which primarily establish outdoor, or ambient, air quality standards, are the primary drivers behind state and local air pollution regulations. However, with a few exceptions, the New Source Performance Standards (see page 5 for more information), federal regulations only set the ambient air quality standards. They do not detail how to accomplish them. The necessary actions to accomplish the federal standards must be developed and implemented by state and local air quality agencies. It is the state and local actions, along with the Federal New Source Performance Standards, that directly impact industrial boilers.

FEDERAL ACTIONS
The Clean Air Act

Nearly all air pollution regulations originate from the Clean Air Act, which was enacted in 1963. The act improved and strengthened pollution prevention programs and was the first major step toward more federal control of air pollution. The first major amendments to the Clean Air Act occurred in 1970. The 1970 amendments set national air quality standards and established performance standards for new sources of pollution. As a result of the 1970 amendments, standards were set for sulfur oxides and nitrogen oxides for several sources, including boilers.

The next significant amendment to the Clean Air Act occurred in 1977. The 1977 amendment enhanced many aspects of the Clean Air Act by implementing a more comprehensive permit program, establishing emission limitations on existing sources, and imposing stricter emission standards on new sources. But most importantly, the 1977 amendment extended compliance deadlines because many geographical areas had not achieved compliance with the ambient air quality standards. After regulating air pollution for almost 15 years, nationwide compliance still had not been achieved.

The most recent amendment to the Clean Air Act occurred in 1990. The 1990 Clean Air Act Amendment has been labelled the most complex, comprehensive, and far-reaching environmental law Congress has ever enacted. The 1990 amendments consist of 11 titles. Some of the titles are revisions of existing titles and others are new titles. As a result, the Clean Air Act now encompasses most aspects of air pollution.

The act:

- Controls air pollution from stationary and mobile sources
- Controls the release of air toxins
- Controls acid rain pollutants (NO_X and SO_X)
- Establishes a massive permit program
- Sets-up enforcement provisions
- Establishes many miscellaneous programs

The Clean Air Act Amendment of 1990

The Clean Air Act, its interpretations and associated implications, are very complex. It would be impractical to list the details of the amendment and the requirements for future activity that the federal government dictates for state governments. For this reason, this section provides basic insight into the implications the act poses for fossil-fuel fired packaged boilers.

As mentioned earlier, the 1990 Clean Air Act Amendment is comprised of 11 titles (see Figure 1). The provisions contained in the titles have the potential to affect nearly every source of air pollution. Although several titles affect industrial boilers, the title having the most impact is Title I, Attainment and Maintenance of the National Ambient Air Quality Standards.

1997 Changes to the Clean Air Act

EPA recently reviewed the current air quality standards for ground-level ozone (commonly known as smog) and particulate matter (or PM). Based on new scientific evidence, revisions have been made to both standards. At the same time, EPA is developing new programs to control regional haze, which is largely caused by particulate matter and mercury.

Title I - National Ambient Air Quality Standards

The National Ambient Air Quality Standards (NAAQS) are pollution standards set by the federal Environmental Protection Agency (EPA) through the Clean Air Act. The NAAQS set ambient pollutant standards to address seven ‘criteria’ pollutants (see Figure 2):

- Ozone (O_3)
- Carbon Monoxide (CO)
- Nitrogen Dioxide (NO_2)
- Sulfur Dioxide (SO_2)
- PM_{10} (particulate matter with a diameter of less than 10 microns)
- Lead

n 1990 CAAA Titles

Title I - Attainment and Maintenance of the National Ambient Air Quality Standards: Deals with attaining and maintaining the National Ambient Air Quality Standard (NAAQS) for six criteria pollutants.

Title II - Mobile Sources: Establishes stricter emission standards for motor vehicles.

Title III - Hazardous Air Pollutants: Identifies and calls for reductions in 189 toxic pollutants.

Title IV - Acid Deposition Control: Addresses NO_x and SO_2 reduction in large utility boilers (major sources). Regulations for industrial units will be developed shortly.

Title V - Permits: Establishes a comprehensive operating permit program for air emissions.

Title VI - Stratospheric Ozone Protection: Requires a complete phase-out of chlorofluorocarbons (CFCs) and halons.

Title VII - Enforcement: Gives the EPA more administrative enforcement penalties. It is now a felony to knowingly violate the Clean Air Act.

Title VIII - Miscellaneous: Addresses oil drilling and visibility provisions.

Title IX - Clean Air Research: Addresses air pollution research in the areas of monitoring and modeling, health effects, ecological effects, pollution prevention, emission control, and acid rain.

Title X - Disadvantaged Business Concerns: Requires that a portion of federal funds for air research go to disadvantaged firms.

Title XI - Clean Air Employment Transition Assistance: Provides additional unemployment benefits to workers for retraining who are laid off because of compliance with the Clean Air Act.

figure 1

n National Ambient Air Quality Standards

Pollutant	Primary Standards	Averaging Times	Secondary Standards
Carbon Monoxide	9 ppm (10 mg/m^3)	8-hour[1]	None
	35 ppm (40 mg/m^3)	1-hour[1]	None
Lead	1.5 µg/m^3	Quarterly Average	Same as Primary
Nitrogen Dioxide	0.053 ppm (100 µg/m^3)	Annual (Arithmetic Mean)	Same as Primary
Particulate Matter	50 µg/m^3	Annual[2] (Arithmetic Mean)	Same as Primary
(PM_{10})	150 µg/m^3	24-hour[1]	
Particulate Matter	150 µg/m^3	Annual[3] (Arithmetic Mean)	Same as Primary
($PM_{2.5}$)	65 µg/m^3	24-hour[4]	
Ozone	0.08 ppm	8-hour[5]	Same as Primary
Sulfur Oxides	0.03 ppm	Annual (Arithmetic Mean)	–
	0.14 ppm	24-hour[1]	_
	–	3-hour[1]	0.5 ppm (1300ug/m^3)

[1] Not to be exceeded more than once per year.
[2] To attain this standard, the 3-year average of the weighted annual mean PM_{10} concentration at each monitor within an area must not exceed 50ug/m3.
[3] To attain this standard, the 3-year average of the weighted annual mean $PM_{2.5}$ concentration from single or multiple community-oriented monitors must not exceed 15.0ug/m^3.
[4] To attain this standard, the 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 65 ug/m^3.
[5] To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hor average ozone concentrations measured at each monitor within an area over each year must not exceed 0.08 ppm.

figure 2

The NAAQS are designed to protect humans and the environment from the adverse effects of air pollutants. Unlike emission limitations, which specify allowable pollutant releases from air pollution sources, ambient standards set forth maximum allowable concentrations of pollutants in the outdoor, or ambient, air. The Clean Air Act sets specific deadlines for every area in the country not in compliance with the NAAQS to enact regulations for achieving these standards.

Attainment and Nonattainment

Classified Ozone Nonattainment Areas

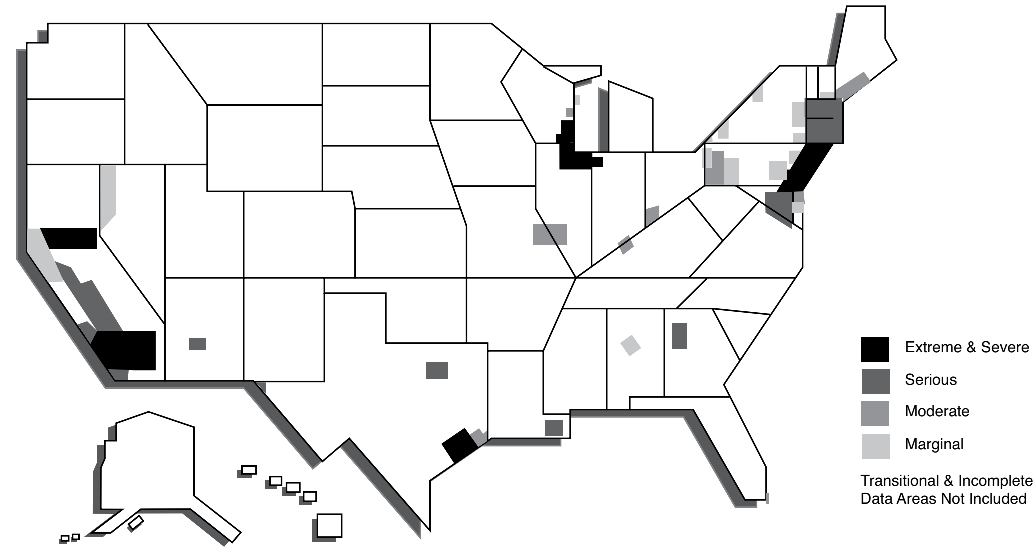

figure 3

Through the NAAQS, areas of the United States are designated as attainment and nonattainment. Simply put, areas with ambient pollutant levels below the NAAQS are in attainment. Areas with pollutant levels above the NAAQS are in nonattainment.

> **Note:** Attainment/Nonattainment designation is made on a pollutant-by-pollutant basis for all pollutants included in the NAAQS. Therefore, an area can be designated as attainment and nonattainment because it may be in compliance with the NAAQS for one pollutant but not another.

The most common pollutant for which the NAAQS are exceeded is ozone. Ozone is not emitted directly from smokestacks, tailpipes, or other pollution sources. Instead, it is formed by the reaction of volatile organic compounds (VOCs) and nitrogen oxides (NO_x) in the presence of sunlight. NO_x and VOCs are released into the air by

Classified Carbon Monoxide Nonattainment Areas

figure 4

automobiles, factories, and several other sources, including industrial boilers. As of January, 1994, there are 101 cities and towns violating the NAAQS for ozone (see Figure 3). Ozone nonattainment areas are classified into one of five categories, based on the amount by which the local ozone levels exceed the NAAQS. From highest to lowest degree of nonattainment, the categories are: extreme; severe; serious; moderate; and marginal.

The second most common nonattainment pollutant is carbon monoxide. As of January, 1994, 52 metropolitan areas exceed the NAAQS for carbon monoxide (see Figure 4). Carbon monoxide nonattainment areas are classified as serious and moderate, depending on the amount local CO levels exceed the NAAQS for CO.

Although the number of nonattainment areas are not as great as they are for ozone and carbon monoxide, there are several areas violating the NAAQS for PM_{10}, NO_x, SO_x, and lead. Areas violating the NAAQS for PM_{10} are subclassified as serious or moderate. There are no subclassifications for NO_x, SO_x, and lead.

A listing of the ozone, CO, PM_{10}, and SO_2 nonattainment areas as of January, 1994 is included in Appendix A. The classifications of areas are constantly changing as air pollution levels are continuously under review for attainment/nonattainment designation. For the most current attainment/nonattainment classification, contact your local air pollution control agency.

Offsets

If an owner or operator of a major source wants to release more of a criteria air pollutant, an offset (a reduction of the criteria air pollutant by an amount somewhat greater than the planned increase) must be obtained somewhere else, so that permit requirements are met and the nonattainment area keeps moving toward attainment. The company must also install tight pollution controls. An increase in a criteria air pollutant can be offset with a reduction of the pollutant from some other stack at the same plant or at another plant owned by the same or some other company in the nonattainment area. Since total polllution will continue to go down, trading offsets among companies is allowed. This is one of the market approaches to cleaning up air pollution in the Clean Air Act.

State Implementation Plans

Through the NAAQS, the EPA has established pollution standards for six criteria pollutants. However, the NAAQS are only an interim step in the regulation of these pollutants. The ambient standards do not tell an individual polluter what must be done to control their emissions. Rather, Title I of the 1990 Clean Air Act Amendments delegates the responsibility to the states by requiring local nonattainment areas to develop a plan to reduce ambient pollution levels below the NAAQS.

Nonattainment characteristics vary by area and pollutant. A nonattainment area can be affected by weather, geography, demographics, and other forces. Therefore, regulations established for one area may not be effective in another area. This is why the Federal EPA does not establish general, source-specific regulations for all nonattainment areas. The responsibility is assigned to the states. The states are required to develop State Implementation Plans, or SIPs. SIPs include regulations addressing individual pollution sources in order to achieve the pollutant reductions necessary to comply with the NAAQS.

SIPs must address several elements of air pollution control as required by the EPA. The elements include:

- Attainment of the NAAQS within specified deadlines
- Emission limitations for individual sources
- Monitoring provisions
- Permit programs
- Several miscellaneous provisions

A SIP is developed as follows. State regulation developers draft the SIP. Then it undergoes public comment. Next, it is submitted to the EPA for review. The EPA has established submittal dates for the SIPs, which vary depending on the nonattainment status of the local area. Many states have missed the deadlines and are still developing their SIPs. Once the EPA reviews the SIP, it is either approved or, if it fails to fulfill all requirements, the plan could be returned to the state for revision, or the EPA could draft a plan or portions of the plan for the state.

Note: You can obtain a copy of the sections of any SIP applying to industrial boilers by contacting your state air quality agency. It is important to become familiar with the SIP in your state, as the provisions within the SIP may directly impact industrial boilers.

New Source Performance Standards

One situation where the Federal EPA has established nationally uniform source-specific regulations is through the New Source Performance Standards, or NSPS. The standards, which set minimal requirements for individual sources, address approximately 65 categories of new or modified stationary sources, including industrial boilers. However, because the NSPS are not based on the nonattainment status of the local area, they may result in over control in some locations and under control in others.

The NSPS for industrial boilers regulate levels for NO_x, SO_x, and particulate matter. The regulated pollutants and requirements vary for different fuels and boiler sizes. There are currently three categories for the NSPS:

- Boilers with inputs greater than 250 MMBtu/hr
- Boilers with inputs between 100-250 MMBtu/hr
- Boilers with inputs between 10-100 MMBtu/hr

The current Small Boiler NSPS apply to all new, modified, or reconstructed boilers with inputs between 10-100 MMBTU/hr where construction, modification, or reconstruction commenced after June 9, 1989. They set emission standards for SO_x and particulate matter for boilers firing coal, distillate and residual oil, and wood. The NSPS also dictate record keeping requirements regarding fuel usage for all fuels, including natural gas. Record keeping requirements and compliance standards for the different emissions depends on the type of fuel fired and on the boiler size. For a summary of the Small Boiler NSPS, see Figure 5.

Expect to hear more about the NSPS. The 1990 Clean Air Act Amendments require the EPA to review the current NSPS and modify the requirements to incorporate new technologies for several source categories addressed through the NSPS.

STATE ACTIONS
Nonattainment Areas

Air quality monitoring stations operate throughout the United States to assess local air quality. Readings are continuously taken from the stations to monitor the six criteria pollutants regulated through the NAAQS. The levels of the pollutants are continuously evaluated. If levels exceed the NAAQS, the area is classified as nonattainment.

States must determine the boundaries of nonattainment areas through the use of the data collected. The boundaries of nonattainment and attainment areas can be difficult to define. For example, because of the high population in the northeastern United States and the close proximity of major cities, an ozone nonattainment area may enact regulations to bring the area into compliance. But because of the influence of the surrounding cities, attainment may not be achieved. Ozone nonattainment areas in the northeast are forming alliances to develop regulations because of the influence of pollution from a broad area. For example, uniform regulations are being developed for eleven states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont) in what is designated by the Federal EPA as the Northeast Ozone Transport Region.

Emission Inventories

Once a nonattainment area is defined, the pollution sources are identified and the quantity of emissions from the sources are evaluated. To help states determine the types and levels of emissions for the various sources, the EPA has established the AP-42 Compilation of Air Pollutant Emission Factors. The document indicates average emission levels emitted by various equipment and industries. Once the individual sources in a nonattainment area have been identified, the AP-42 can be used to determine the type and level of emissions. The emission inventory is a valuable tool, which can be used to evaluate different regulatory actions and to calculate the reduction of emissions and the impact on the total emissions.

The average emission levels in AP-42 have sometimes been used as a standard for equipment performance by regulators who are unfamiliar with the equipment. Using the AP-42 levels as pollution standards is not the intent of the AP-42. The AP-42 was developed to provide a “rule-of-thumb” to estimate emissions for a broad category of equipment. Specific emission levels for sites need to be evaluated on a site-specific basis, as the AP-42 states. And because the AP-42 is based on averages, half of the sites reviewed and half of the applications exceed the pollutant levels in the AP-42. In fact, few applications are below all the pollutant averages listed in the AP-42.

Note: Because few applications are below all the pollutant levels listed the AP-42, the AP-42 emission levels should not be used to permit boilers. The boiler/burner manufacturer should be contacted

Summary of Federal EPA Rules

NEW SOURCE PERFORMANCE STANDARDS
For Boilers 10-100 MMBtu/hr, built or modified after 6-9-1989

RULES FOR SULFUR DIOXIDE (SO_2) EMISSIONS

1. **Coal Firing**
   - 1.2 lb SO_2/MMBtu Limit all 10-100 MMBtu.
   - 90% SO_2 reduction required if > 75 MMBtu and > 55% annual coal capacity.
   - Initial performance testing required within 180 days of start-up.
   - 30 day rolling average used in calculations.
   - Continuous Emission Monitoring System (CEMS) required except:
     - Fuel analysis may be used (before cleanup equipment).
     - Units < 30 MMBtu may use supplier certificate for compliance.
2. **Residual Oil Firing**
   - Limit of 0.5 lb SO_2/MMBtu or 0.5% sulfur in fuel.
   - CEMS required to meet SO_2 limit except fuel analysis can be used as fired condition before cleanup equipment.
   - Fuel sulfur limit compliance can be:
     - Daily as fired fuel analysis.
     - As delivered (before used) fuel analysis.
     - Fuel supplier certificate for units < 30 MMBtu.
   - Initial performance testing and 30 day rolling average required except for supplier certificate.
3. **Distillate Oil Firing (ASTM grades 1 and 2)**
   - Limit 0.5% sulfur in fuel (required in ASTM standard).
   - Compliance by fuel supplier certificate.
   - No monitoring or initial testing required.

RULES FOR PARTICULATE MATTER (PM) EMISSIONS

1. **General**
   - Limits established only for units between 30-100 MMBtu.
   - All coal, wood and residual oil fired units > 30 MMBtu must meet opacity limit of 20%, except one 6 minute/hour opacity of 27%. CEMS required to monitor opacity.
2. **Coal Firing**
   - 0.05 lb/MMBtu limit if > 30 MMBtu and > 90% annual coal capacity.
   - 0.10 lb/MMBtu limit if > 30 MMBtu and < 90% annual coal capacity.
   - 20% opacity (CEMS) and initial performance tests on both PM limit and opacity.
3. **Wood Firing**
   - 0.10 lb/MMBtu limit if > 30 MMBtu and > 30% annual wood capacity.
   - 0.30 lb/MMBtu limit if > 30 MMBtu and < 30% annual wood capacity.
   - Opacity limits and initial testing per above.
4. **Oil Firing**
   - All units > 30 MMBtu subject to opacity limit, only residual oil firing must use CEMS.
   - Initial performance testing required.

REPORTING REQUIREMENTS

- Owners or operators of all affected units must submit information to the administrator, even if they are not subject to any emission limits or testing. Required reports include:
  - Information on unit size, fuels, start-up dates and other equipment information.
  - Initial performance test results, CEMS performance evaluation.
  - Quarterly reports on SO_2 and/or PM emission results, including variations from limits and corrective action taken.
  - For fuel supplies certificate, information on supplies and details of sampling and testing for coal and residual oil.
  - Records must be maintained for two years.

figure 5

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to obtain the emissions levels that should be used to permit the boiler.

Appendix B shows the AP-42 emission levels for industrial boilers firing natural gas, distillate and residual oils, and propane.

State Activities

All of the activities mentioned earlier eventually will result in some form of regulation for areas classified as nonattainment. While it is impossible to predict what any given state will do, it appears that many are following the lead of Southern California. Southern California has the worst air quality in the United States. Their efforts toward cleaner air are usually considered to be the basis for establishing regulations in other areas of the country in high degrees of ozone nonattainment.

Regulations will change as new technologies allow for lower emission levels. Also, adjustments will be made based on the improvements in air quality. It is necessary to stay involved with air quality regulations to keep appraised of any regulation changes.

The application of regulations can take several different forms and is often based on the degree of nonattainment. Required controls are based on the size of equipment, total emissions from a facility, type of fuels used, or a combination of factors. For example, in ozone nonattainment areas, the required measures depend on the nonattainment degree and total emissions from the facility. Levels set by the EPA help identify 'major' sources of VOCs and NO_x emissions. If the total NO_x or VOC emissions for a facility located in an ozone nonattainment area exceed the pre-established major source trigger levels, extensive computer modeling and stringent regulations may be necessary. The major source trigger levels are indicated in tons per year and apply to the total NO_x or VOC emissions for all sources located at the facility. The major source trigger levels for the different ozone nonattainment classifications are shown in Figure 6.

To put this in perspective, a facility with three 800 horsepower boilers firing natural gas 24 hours per day, 365 days per year, would result in an uncontrolled NO_x level of 57 tons per year (based on a NO_x level of 0.13 lb/MMBtu). Referring to major source trigger levels specified in Figure 6, consider the following. If the facility is located in a moderate or marginal ozone nonattainment area, it is not a major source. But, if it is located in a serious, severe, or extreme ozone nonattainment area, it is a major source and would have specific air quality NO_x control requirements. These requirements may include:

- An extensive permit application
- Dispersion modeling
- Procurement of emission offsets
- Stringent emission limitations

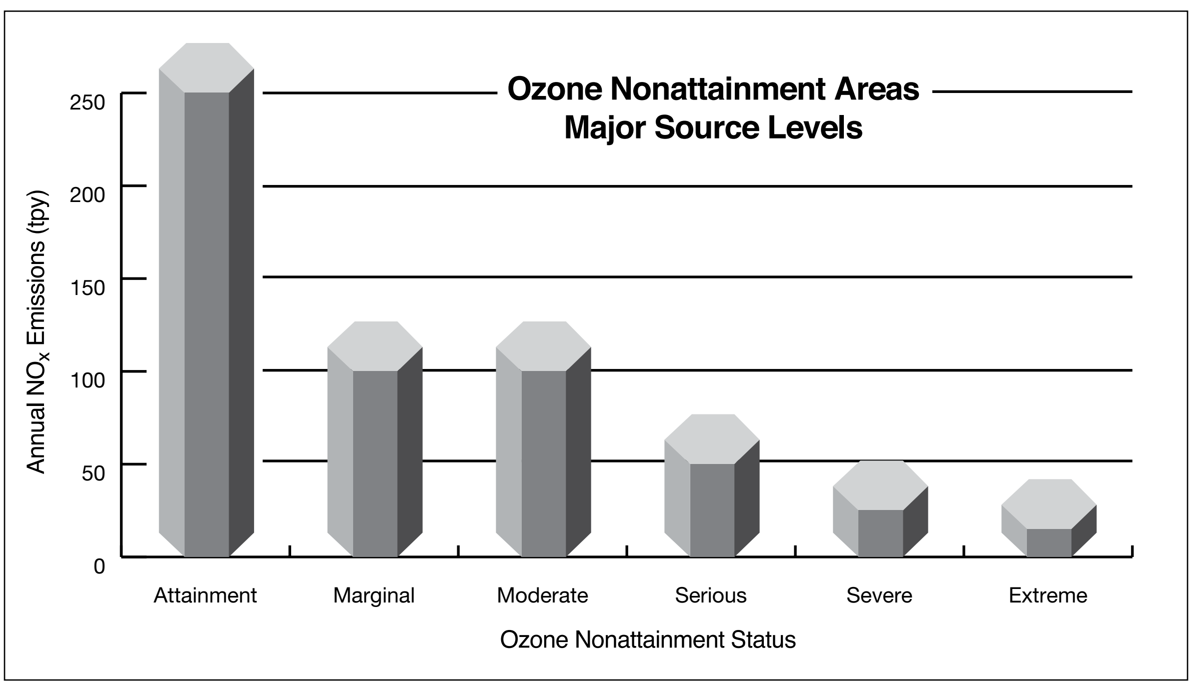


figure 6

- Continuous emission monitoring equipment
- Extensive emission controls
- Detailed fuel usage recording

An Emission Alphabet

If a facility is classified as a major source, regulations may require technology equivalent to:

- Maximum Achievable Control Technology (MACT)
- Lowest Achievable Emission Rate (LAER)
- Reasonably Available Control Technology (RACT)

All three regulations are based on technology and do not directly specify an emission level requirement. Instead, they require an evaluation of each affected facility in order to determine the applicable emission and technology requirements. As new technologies are developed, which may result in greater emission reductions than currently available, they must be included in the evaluation. Technology-based regulations have been utilized for years and proven effective.

Maximum Achievable Control Technology

Maximum Achievable Control Technology (MACT) is a regulation requiring an evaluation of all current technologies to determine the emission limitation for a new source. It is established on a case-by-case basis for sources and takes into account energy, environmental, and economic impacts. MACT evaluates the optimum effectiveness of a control technology against the extremity of the environmental condition.
In establishing MACT for a source, cost is not the only the driving factor. When cost is a consideration, the equipment (cost) is compared to the annual emission reductions in order to determine a figure in dollars per ton of pollutant removed (see Figure 7). The comparison is called the cost effectiveness of the technology.

The regulations requiring MACT set a maximum cost figure that the polluter can spend in order to meet local emission requirements. If the cost effectiveness of the technology is above the figure, the technology is not required and the next lower cost technology MACT is evaluated. The process of reviewing each technology in decreasing order of cost is called Top Down BACT. The Top Down BACT process assures that the source achieves the lowest emission level within the required cost effectiveness.

Typical regulations in areas of moderate and serious nonattainment for ozone require boiler owners to utilize NO_x control technologies that result in a cost effectiveness figure between $3,000-

MACT/RACT Cost Effectiveness

$$\frac{\text{Annualized Costs of Control Equipment*}}{\text{Uncontrolled Emission Rate} - \text{Controlled Emission Rate}}$$

Example:

Uncontrolled Emission Rate	=	18 tons/year
Controlled Emission Rate	=	4 tons/year
Annualized Cost of Emission Control Method	=	$70,000/year

$$\frac{\$70{,}000}{18\text{ tpy} - 4\text{ tpy}} = \$5{,}000\text{/ton of } NO_x \text{ removed}$$

* considering hardware, installation, operating and maintenance costs

figure 7

$10,000 per ton of NO_x removed. In severe and extreme ozone nonattainment areas, the required cost effectiveness can be as high as $24,500 per ton of NO_x controlled.

Reasonably Available Control Technology

Reasonably Available Control Technology (RACT) is similar to BACT in that cost effectiveness is associated with the boiler owners' emission requirements. The difference is that RACT is utilized on existing sources while MACT is used on new or modified sources. The cost requirements for RACT are less and are intended to be available at a 'reasonable' cost.

Many states with ozone nonattainment areas have submitted proposed RACT regulations to the EPA for approval as part of the SIP requirements. Many of the regulations set emission limitations from industrial boilers that can be achieved through burning cleaner fuels (i.e., natural gas), utilizing low NO_x technologies, or a combination of both. Owners of industrial boilers located in ozone nonattainment areas should be familiar with the RACT requirements in their states.

Lowest Achievable Emission Rates

Some regulations require technology equivalent to the Lowest Achievable Emission Rate (LAER) be utilized in new major sources located in nonattainment areas. LAER is different from BACT in that it has no economic justification associated with its requirements. When required, technology equivalent to LAER must be installed regardless of costs impacts. It is the most stringent of all technology-based regulations.

Permits

The permit program established under Title V of the 1990 Clean Air Act Amendments will undoubtedly affect the way each state conducts its permitting process. Title V requires a review (and most likely a revision) of each state's permitting program in order to ensure that the state's permit program meets all Federal EPA requirements. Elements of state permit programs that could be affected include:

- The permit application process
- Monitoring and reporting requirements
- Permit renewal process
- Several other permitting issues

By November of 1993, states were required to submit proposed permitting programs to the EPA. By November of 1994, the EPA must approve or disapprove the proposed permit programs. The new permit programs will go into effect when approved by the EPA or the EPA promulgates a program for states failing to submit a satisfactory program.

Currently, several states have implemented a two-stage permitting process. In the first stage, a permit to construct must be obtained. The permit usually requires a detailed description of the installation, including information such as the type and size of equipment and associated emissions. The second stage of the permit process consists of obtaining an operating permit. In some states, emission testing may be part of the requirement for obtaining an operating permit.

Although many states may have the same basic permitting structure, the details and requirements of the permitting process are different for each state. It is important to be aware of not only the state permitting requirements, but also any federal requirements (i.e., Small Boiler New Source Performance Standards) that may be applicable. It is particularly important to be familiar with the permitting process as the new federal and state programs are implemented. Nearly every source of air pollution will be affected. Any violators may face stiff penalties.

POLLUTANTS AND CONTROL TECHNIQUES

A pollutant can be defined as matter that contaminates air, soil, or water. Air pollutants are airborne contaminants that produce unwanted effects on humans and the environment. They occur as solids, liquid droplets, gases, or combinations of these forms. Generally, air pollutants are classified into two major categories:

- Primary Pollutants - pollutants emitted directly from identifiable sources
- Secondary Pollutants - pollutants formed by interaction between two or more primary pollutants

To protect humans and the environment from the adverse effects of air pollutants, the EPA has established the National Ambient Air Quality Standards (see Figure 2, page 3). The Clean Air Act Amendments of 1990 require areas in noncompliance for one or more of the NAAQS pollutants to implement regulations to reduce ambient levels. All six pollutants addressed in the National Ambient Air Quality Standards are directly or indirectly related to the combustion process. The following sections describe the formation and control of the pollutants in industrial boilers, discuss their impact on humans and the environment, and describe the current emission control technologies.

Nitrogen Compounds

Although there is evidence proving NO_x, in itself, is harmful to humans, the main reason NO_x is considered an environmental problem is because it initiates reactions that result in the production of ozone and acid rain. Ozone and acid rain can damage fabric, cause rubber to crack, reduce visibility, damage buildings, harm forests and lakes, and cause health problems. By controlling NO_x levels, along with other contributing primary pollutants, the levels of acid rain and ozone can be reduced.

The principal nitrogen pollutants generated by boilers are nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as NO_x. The majority of NO_x produced during combustion is NO (95%). Once emitted into the atmosphere, NO reacts to form NO_2. It is NO_2 that reacts with other pollutants to form ozone.

The contribution from different NO_x sources to the total NO_x levels varies among metropolitan areas. In general, the contribution of mobile sources to the total NO_x level ranges from 60 to 80 percent: For stationary sources, it ranges between 20 and 40 percent. A significant portion of the NO_x from stationary sources can be attributed to residential, commercial, and industrial sources, including industrial boilers. In industrial boilers, NO_x is primarily formed in two ways; thermal NO_x and fuel NO_x.

Thermal NO_x

Thermal NO_x is formed when nitrogen and oxygen in the combustion air combine with one another at the high temperatures in a flame. Thermal NO_x makes up the majority of NO_x formed during the combustion of gases and light oils.

Fuel NO_x

Fuel NO_x is formed by the reaction of nitrogen in the fuel with oxygen in the combustion air. It is rarely a problem with gaseous fuels. But in oils containing significant amounts of fuel-bound nitrogen, fuel NO_x can account for up to 50% of the total NO_x emissions.

NO_x emissions from boilers are influenced by many factors. The most significant factors are flame temperature and the amount of nitrogen in the fuel. Other factors affecting NO_x formation are excess air level and combustion air temperature.

While flame temperature primarily affects thermal NO_x formation, the amount of nitrogen in the fuel determines the level of fuel NO_x emissions. Fuel containing more nitrogen results in higher levels of NO_x emissions (see Figure 9). Most NO_x control technologies for industrial boilers, with inputs less than 100 MMBtu/hr, reduce thermal NO_x and have little affect on fuel NO_x. Fuel NO_x is most economically reduced in commercial and industrial boilers by switching to cleaner fuels, if available.

NO_x Control Technologies

NO_x controls can be classified into two types; post combustion methods and combustion control techniques. Post combustion methods address NO_x emissions after formation while combustion control techniques prevent the formation of NO_x during the combustion process. Post combustion methods tend to be more expensive than combustion control techniques and generally are not used on boilers with inputs of less than 100 MMBtu/hr. Following is a list of different NO_x control methods.

Effects of Fuel-Bound Nitrogen on NO_x Emissions for Fuel Oils

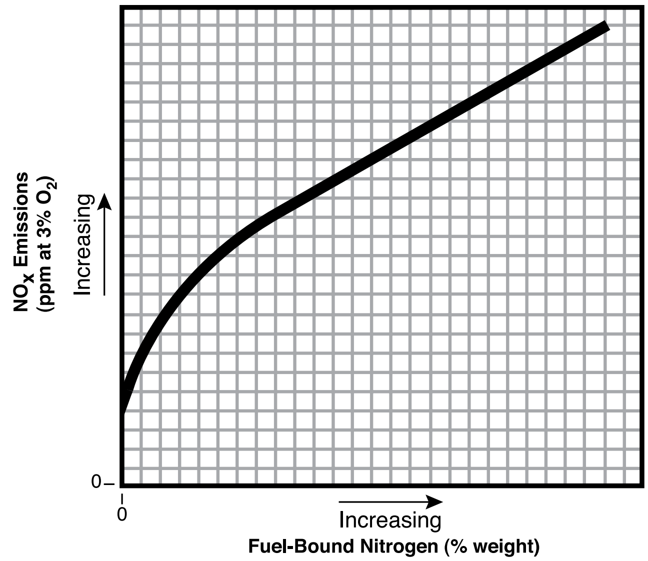


figure 8

Post Combustion Control Methods

Selective Non-Catalytic Reduction

Selective Catalytic Reduction

Combustion Control Techniques

Low Excess Air Firing

Low Nitrogen Fuel Oil

Burner Modifications

Water/Steam Injection

Flue Gas Recirculation

Each method results in a different degree of NO_x control. For example, when firing natural gas, low excess air firing typically reduces NO_x by 10%, flue gas recirculation by 75%, and selective catalytic reduction by 90%.

Post Combustion Control Methods
Selective Non-catalytic Reduction

Selective non-catalytic reduction involves the injection of a NO_x reducing agent, such as ammonia or urea, in the boiler exhaust gases at a temperature of approximately 1400-1600°F (see Figure 10). The ammonia or urea breaks down the NO_x in the exhaust gases into water and atmospheric nitrogen. Selective non-catalytic reduction reduces NO_x up to 50%. However, the technology is extremely difficult to apply to industrial boilers that modulate frequently. This is because the ammonia (or urea) must be injected in the flue gases at a specific flue gas temperature. And in industrial boilers that modulate frequently, the location of the exhaust gases at the specified temperature is constantly changing. Thus, it is not feasible to apply selective non-catalytic reduction to industrial boilers that have high turndown capabilities and modulate frequently.

Selective Catalytic Reduction

Selective catalytic reduction involves the injection of ammonia in the boiler exhaust gases in the presence of a catalyst (see Figure 11). The catalyst allows the ammonia to reduce NO_x levels at lower exhaust temperatures than selective non-catalytic reduction. Unlike selective non-catalytic reduction, where the exhaust gases must be approximately 1400-1600°F, selective catalytic reduction can be utilized where exhaust gases are between 500° and 1200°F, depending on the catalyst used. Selective catalytic reduction can result in NO_x reductions up to 90%. However, it is costly to use and rarely can be cost justified on boilers with inputs less than 100 MMBtu/hr.

Combustion Control Techniques

Combustion control techniques reduce the amount of NO_x emission by limiting the amount of NO_x formation during the combustion process. This is typically accomplished by lowering flame temperatures. Combustion control techniques are more economical than post combustion methods and are frequently utilized on industrial boilers requiring NO_x controls.

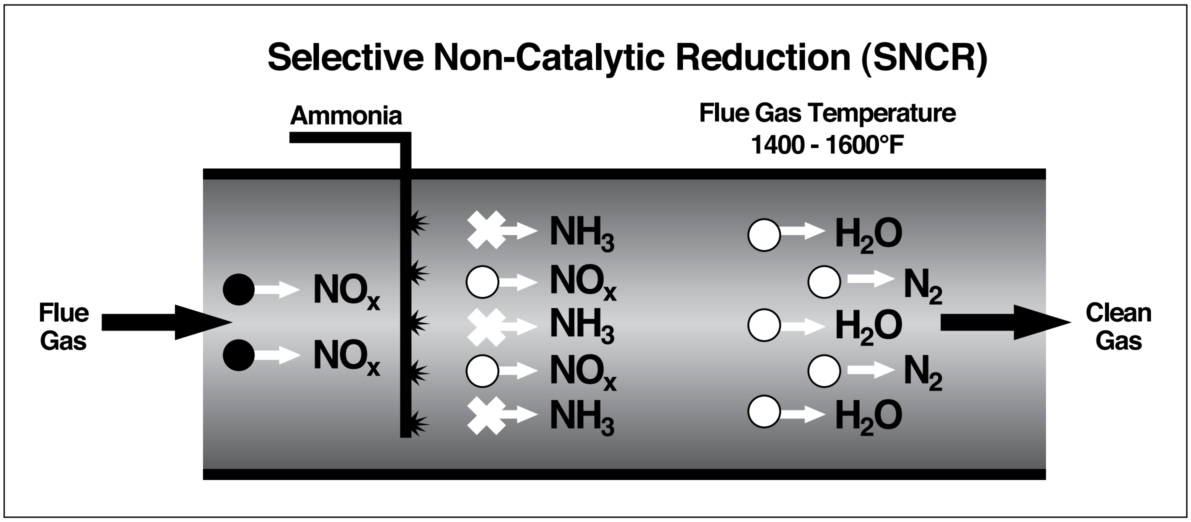


figure 9

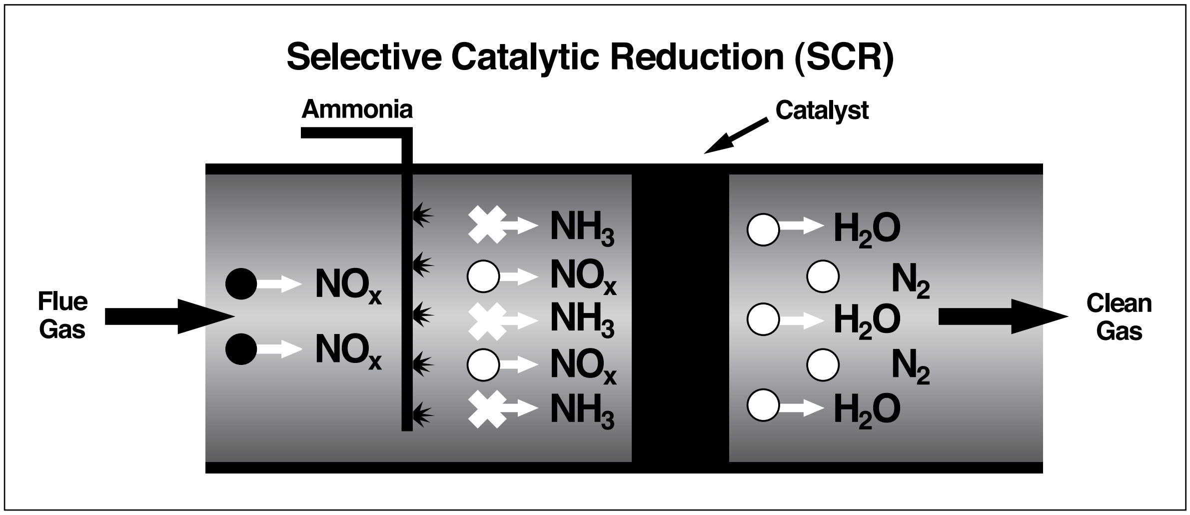


figure 10

Low Excess Air (LEA) Firing

As a safety factor to assure complete combustion, boilers are fired with excess air. One of the factors influencing NO_x formation in a boiler is the excess air levels. High excess air levels (>45%) may result in increased NO_x formation because the excess nitrogen and oxygen in the combustion air entering the flame will combine to form thermal NO_x. Low excess air firing involves limiting the amount of excess air that is entering the combustion process in order to limit the amount of extra nitrogen and oxygen that enters the flame. Limiting the amount of excess air entering a flame is usually accomplished through burner design and can be optimized through the use of oxygen trim controls. Low excess air firing can be used on most boilers and generally results in overall NO_x reductions of 5-10% when firing natural gas.

Low Nitrogen Fuel Oil

When firing fuel oils, NO_x formed by fuel-bound nitrogen can account for 20-50% of the total NO_x level. Utilizing fuel oils with lower nitrogen contents results in lower NO_x levels. One method to reduce NO_x levels from boilers firing distillate oils is through the use of low nitrogen fuel oil. Low nitrogen oils can contain up to 15-20 times less fuel-bound nitrogen than standard No. 2 oil (less than 0.001% fuel-bound nitrogen). When low NO_x oil is fired in firetube boilers utilizing flue gas recirculation, NO_x reductions of 60%-70% over NO_x emissions from standard No. 2 oils have been achieved. Low nitrogen oil is currently used most frequently in Southern California.

Burner Modifications

Burner modifications for NO_x control involve changing the design of a standard burner in order to create a larger flame. Enlarging the flame results in lower flame temperatures and lower thermal NO_x formation which, in turn, results in lower overall NO_x emissions. The technology can be applied to most boiler types and sizes. It is most effective when firing natural gas and distillate fuel oil and has little affect on boilers firing heavy oil. To comply with the more stringent regulations, burner modifications must be used in conjunction with other NO_x reduction methods, such as flue gas recirculation. If burner modifications are utilized exclusively to achieve low NO_x levels (30 ppm), adverse affects on boiler operating parameters such as turndown, capacity, CO levels, and efficiency may result. It is important to address all aspects of NO_x control when selecting NO_x control technologies (see Side Bar, this page).

Water/Steam Injection

Water or steam injection can be utilized to reduce NO_x levels. By introducing water or steam into the flame, flame temperatures are reduced, thereby lowering thermal NO_x formation and overall NO_x levels. Water or steam injection can reduce NO_x up to 80% (when firing natural gas) and can result in lower reductions when firing oils. There is a practical limit to the amount of water or steam that can be injected into the flame before condensation problems are experienced. Additionally, under normal operating conditions, water/steam injection can result in a 3-10% efficiency loss. Many times water or steam injection is used in conjunction with other NO_x control methods such as burner modifications or flue gas recirculation.

Flue Gas Recirculation

Flue gas recirculation, or FGR, is the most effective method of reducing NO_x emission from industrial boilers with inputs below 100 MMBtu/hr. FGR entails recirculating a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NO_x formation. It is currently the most effective and popular low NO_x technology for firetube and watertube boilers. And, in many applications, it does not require any additional reduction equipment to comply with the most stringent regulations in the United States.

Flue gas recirculation technology can be classified into two types; external or induced.

External flue gas recirculation utilizes an external fan to recirculate the flue gases back into the combustion zone. External piping routes the exhaust gases from the stack to the burner. A valve controls the recirculation rate, based on boiler input.

Induced flue gas recirculation utilizes the combustion air fan to recirculate the flue gases back into the combustion zone. A portion of the flue gases are routed by duct work or internally to the combustion air fan, where they are premixed with the combustion air and introduced into the flame through the burner. New designs of induced FGR that utilize an integral FGR design are becoming popular among boiler owners and operators because of their uncomplicated design and reliability.

Theoretically, there is no limit to the amount of NO_x reduction with FGR; practically, there is a physical, feasible limit. The limit of NO_x reduction varies for different fuels - 90% for natural gas and 25-30% for standard fuel oils.

The current trends with low NO_x technologies are to design the boiler and low NO_x equipment as a package. Designing as a true package allows the NO_x control technology to be specifically tailored to match the boiler's furnace design features, such as shape, volume, and heat release. By designing the low NO_x technology as a package with the boiler, the effects of the low NO_x technology on boiler operating parameters (turndown, capacity, efficiency, and CO levels) can be addressed and minimized.

SIDE BAR:

CHOOSING THE BEST NO_X TECHNOLOGY FOR THE JOB

What effect does NO_x control technology ultimately have on a boiler's performance? Certain NO_x controls can worsen boiler performance while other controls can appreciably improve performance. Aspects of the boiler performance that could be affected include turndown, capacity, efficiency, excess air, and CO emissions.

Failure to take into account all of the boiler operating parameters can lead to increased operating and maintenance costs, loss of efficiency, elevated CO levels, and shortening of the boiler's life.

The following section discusses each of the operating parameters of a boiler and how they relate to NO_x control technology.

TURNDOWN

Choosing a low NO_x technology that sacrifices turndown can have many adverse effects on the boiler. When selecting NO_x control, the boiler should have a turndown capability of at least 4:1 or more, in order to reduce operating costs and the number of on/off cycles. A boiler utilizing a standard burner with a 4:1 turndown can cycle as frequently as 12 times per hour or 288 times a day because the boiler must begin to cycle at inputs below 25% capacity.

With each cycle, pre- and post-purge air flow removes heat from the boiler and sends it out the stack. The energy loss can be reduced by using a high turndown burner (10:1), which keeps the boiler on at low firing rates.

Every time the boiler cycles off, it must go through a specific start-up sequence for safety assurance. It takes about one to two minutes to get the boiler back on line. If there is a sudden load demand, the response cannot be accelerated. Keeping the boiler on line assures a quick response to load changes.

Frequent cycling also deteriorates the boiler components. Maintenance increases, the chance of component failure increases, and boiler downtime increases. So, when selecting NO_x control, always consider the burner's turndown capability.

CAPACITY

When selecting the best NO_x control, capacity and turndown should be considered together because some NO_x control technologies require boiler derating in order to achieve guaranteed NO_x reductions. For example, flame shaping (primarily enlarging the flame to produce a lower flame temperature - thus lower NO_x levels) can require boiler derating, because the shaped flame could impinge on the furnace walls at higher firing rates.

However, the boiler's capacity requirement is typically determined by the maximum load in the steam/hot water system. Therefore, the boiler may be oversized for the typical load conditions occurring.

If the boiler is oversized, its ability to handle minimum loads without cycling is limited. Therefore, when selecting the most appropriate NO_x control, capacity and turndown should be considered together for proper boiler selection and to meet overall system load requirements.

EFFICIENCY

Some low NO_x controls reduce emissions by lowering flame temperature, particularly in boilers with inputs less than 100 MMBtu/hr. Reducing the flame temperature decreases the radiative heat transfer from the flame and could lower boiler efficiency. The efficiency loss due to the lower flame temperatures can be partially offset by utilizing external components, such as an economizer. Or, the loss can be greatly reduced or eliminated by the boiler/burner design.

One technology that offsets the efficiency loss due to lower flame temperatures in a firetube boiler is flue gas recirculation. Although the radiant heat transfer could result in an efficiency loss, the recirculated flue gases increase the mass flow through the boiler - thus the convective heat transfer in the tube passes increases. The increase in convective heat transfer compensates for losses in radiative heat transfer, with no net efficiency loss. When considering NO_x control technology, remember, it is not necessary to sacrifice efficiency for NO_x reductions.

EXCESS AIR

A boiler's excess air supply provides for safe operation above stoichiometric conditions. A typical burner is usually set up with 10-20% excess air (2-4% O_2). NO_x controls that require higher excess air levels can result in fuel being used to heat the air rather than transferring it to usable energy. Thus, increased stack losses and reduced boiler efficiency occur. NO_x controls that require reduced excess air levels can result in an oxygen deficient flame and increased levels of carbon monoxide or unburned hydrocarbons. It is best to select a NO_x control technology that has little effect on excess air.

CO EMISSIONS

High flame temperatures and intimate air/fuel mixing are essential for low CO emissions. Some NO_x control technologies used on industrial and commercial boilers reduce NO_x levels by lowering flame temperatures by modifying air/fuel mixing patterns. The lower flame temperature and decreased mixing intensity can result in higher CO levels.

An induced flue gas recirculation package can lower NO_x levels by reducing flame temperature without increasing CO levels. CO levels remain constant or are lowered because the flue gas is introduced into the flame in the early stages of combustion and the air fuel mixing is intensified. Intensified mixing offsets the decrease in flame temperature and results in CO levels that are lower than achieved without FGR. Induced FGR lowers CO levels as well as NO_x levels. But, the level of CO depends on the burner design. Not all flue gas recirculation applications result in lower CO levels.

TOTAL PERFORMANCE

Selecting the best low NO_x control package should be made with total boiler performance in mind. Consider the application. Investigate all of the characteristics of the control technology and the effects of the technology on the boiler's performance. A NO_x control technology that results in the greatest NO_x reduction is not necessarily the best for the application or the best for high turndown, adequate capacity, high efficiency, sufficient excess air, or lower CO. The newer low NO_x technologies provide NO_x reductions without affecting total boiler performance.

Sulfur Compounds (SO_x)

The primary reason sulfur compounds, or SO_x, are classified as a pollutant is because they react with water vapor (in the flue gas and atmosphere) to form sulfuric acid mist. Airborne sulfuric acid has been found in fog, smog, acid rain, and snow. Sulfuric acid has also been found in lakes, rivers, and soil. The acid is extremely corrosive and harmful to the environment.

The combustion of fuels containing sulfur (primarily oils and coals) results in pollutants occurring in the form of SO_2 (sulfur dioxide) and SO_3 (sulfur trioxide), together referred to as SO_x (sulfur oxides). The level of SO_x emitted depends directly on the sulfur content of the fuel (see Figure 11). The level of SO_x emissions is not dependent on boiler size or burner design.

Typically, about 95% of the sulfur in the fuel will be emitted as SO_2, 1-5% as SO_3, and 1-3% as sulfate particulate. Sulfate particulate is not considered part of the total SO_x emissions.

Historically, SO_x pollution has been controlled by either dispersion or reduction. Dispersion involves the utilization of a tall stack, which enables the release of pollutants high above the ground and over any surrounding buildings, mountains, or hills, in order to limit ground level SO_x emissions. Today, dispersion alone is not enough to meet more stringent SO_x emission requirements; reduction methods must also be employed.

Methods of SO_x reduction include switching to low sulfur fuel, desulfurizing the fuel, and utilizing a flue gas desulfurization (FGD) system. Fuel desulfurization, which primarily applies to coal, involves removing sulfur from the fuel prior to burning. Flue gas desulfurization involves the utilization of scrubbers to remove SO_x emissions from the flue gases.

Flue gas desulfurization systems are classified as either nonregenerable or regenerable. Non-regenerable FGD systems, the most common type, result in a waste product that requires proper disposal. Regenerable FGD converts the waste byproduct into a marketable product, such as sulfur or sulfuric acid. SO_x emission reductions of 90-95% can be achieved through FGD. Fuel desulfurization and FGD are primarily used for reducing SO_x emissions for large utility boilers. Generally the technology cannot be cost justified on industrial boilers.

For users of industrial boilers, utilizing low sulfur fuels is the most cost effective method of SO_x reduction. Because SO_x emissions primarily depend on the sulfur content of the fuel, burning fuels containing a minimal amount of sulfur (distillate oil) can achieve SO_x reductions, without the need to install and maintain expensive equipment.

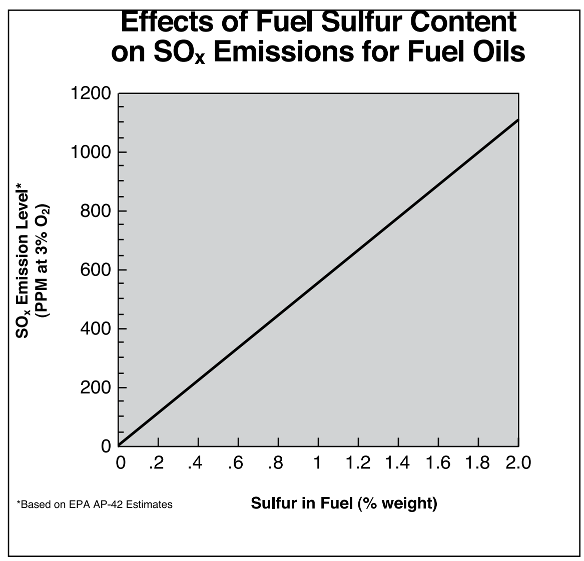


figure 11

Carbon Monoxide (CO)

Carbon monoxide is a pollutant that is readily absorbed in the body and can impair the oxygen-carrying capacity of the hemoglobin. Impairment of the body's hemoglobin results in less oxygen to the brain, heart, and tissues. Short-term over exposure to carbon monoxide can be critical, even fatal, to people with heart and lung diseases. It also may cause headaches and dizziness in healthy people.

During combustion, carbon in the fuel oxidizes through a series of reactions to form carbon dioxide (CO_2). However, 100 percent conversion of carbon to CO_2 is rarely achieved in practice and some carbon only oxidizes to the intermediate step, carbon monoxide.

Older boilers generally have higher levels of CO than new equipment because CO has only recently become a concern and older burners were not designed to achieve low CO levels. In today's equipment, high levels of carbon monoxide emissions primarily result from incomplete combustion due to poor burner design or firing conditions (for example, an improper air-to-fuel ratio) or possibly a compromised furnace seal. Through proper burner maintenance, inspections, operation, or by upgrading equipment or utilizing an oxygen control package, the formation of carbon monoxide can be controlled at an acceptable level.

Particulate Matter (PM)

Emissions of particulate matter (PM) from combustion sources consist of many different types of compounds, including nitrates, sulfates, carbons, oxides, and any uncombusted elements in the fuel. Particulate pollutants can be corrosive, toxic to plants and animals, and harmful to humans.

Particulate matter emissions generally are classified into two categories, PM and PM_{10}. PM_{10} is a particulate matter with a diameter less than 10 microns. All particulate matter can pose a health problem. However, the greatest concern is with PM_{10}, because of its ability to bypass the body's natural filtering system.

PM emissions primarily depend on the grade of fuel fired in the boiler. Generally, PM levels from natural gas are significantly lower than those of oils. Distillate oils result in much lower particulate emissions than residual oils.

When burning heavy oils, particulate levels mainly depend on four fuel constituents: sulfur, ash, carbon residue, and asphaltines. The constituents exist in fuel oils, particularly residual oils, and have a major effect on particulate emissions. By knowing the content of the components, the particulate emissions for the oil can be estimated.

Methods of particulate control vary for different types and sizes of boilers. For utility boilers, electrostatic precipitators, scrubbers, and baghouses are commonly utilized. For industrial and commercial boilers, the most effective method is to utilize clean fuels. The emission levels of particulate matter can be lowered by switching from a residual to a distillate oil or by switching from a distillate oil to a natural gas. Additionally, through proper burner set-up, adjustment and maintenance, particulate emissions can be minimized, but not to the extent accomplished by switching fuels.

Ozone (O_3)

Ozone is a highly reactive form of oxygen. Ground level ozone is a secondary pollutant formed by the reaction of volatile organic compounds (VOCs) with nitrogen oxides (NOx) in the presence of sunlight. Ozone formed at the ground level is the main component of smog. It is known to irritate the eyes, nose, throat, and lungs, and also cause damage to crops. Ground level ozone should not be confused with ozone in the upper atmosphere.

Since ozone is formed by the reaction of VOCs and NO_x, methods of ozone reduction focus on the control of these two pollutants. Recent studies show that reducing NO_x emissions in several ozone nonattainment areas would be beneficial in meeting federal ozone standards.

Sources of VOCs are automobiles, solvents, paints, domestic products and, in nature, decomposition of organic materials such as wood and grass. Although a major source of VOCs is automobiles, the ozone standards also address stationary sources; including boilers. Regulations limiting VOC emissions from stationary combustion sources are relatively new. The regulations originally applied only to large utility boilers, but now are beginning to address industrial boilers. These regulations are primarily at the state level and vary among states.

VOCs are compounds containing combinations of carbon, hydrogen and sometimes oxygen. They can be vaporized easily at low temperatures. They often are referred to as hydrocarbons and generally are divided into two categories — methane and non-methane hydrocarbons.

VOCs can result from poor combustion but, more commonly, result from vaporization of fuels and paints. Leaks in oil or gas piping, and even the few drops of gasoline spilled when filling an automobile, are sources of VOCs.

Control of VOC emissions is best accomplished by maintaining proper combustion conditions. The use of controls to maintain proper air-to-fuel ratios and periodic burner maintenance checks should result in reducing VOC emissions below imposed limits.

Note: If a boiler is operated improperly or is poorly maintained (incorrect air/fuel ratio, inadequate atomizing pressure for oil burners, and improper air and fuel pressures), the concentration of VOCs may increase by several orders of magnitude.

Lead

Lead poisoning can lead to diminished physical fitness, fatigue, sleep disturbance, headache, aching bones and muscles, and digestive upset, including anorexia. Lead poisoning primarily involves the gastrointestinal tract and the peripheral and central nervous systems.

Lead emissions are primarily a result of gasoline combustion in automobile engines and depend highly on the lead content of the fuel. Efforts to reduce lead emissions have focused on the use of lead-free fuels, particularly in automobiles. New blends of gasoline containing lower levels of lead additives continue to be introduced.

The impact of lead emission regulations in industrial boilers that burn standard fuels has been minimal because the fuels generally contain little or no lead. Boilers that fire alternate fuels containing lead are subject to stringent federal, state, and local regulations. For example, under the Federal Resource Conservation Recovery Act (RCRA), waste oil to be burned as fuel in an industrial boiler must contain less than 50 ppm lead. As a result of such strict regulations, the use of fuel containing lead in industrial boilers is limited.

CONCLUSION

We hope you have a better grasp of how federal, state, and local governments are regulating air pollution. We also hope you have a better understanding of NO_x and CO emissions and industrial boiler control technologies.

When you need to specify or purchase an industrial boiler with emission control technology, your local Cleaver-Brooks authorized representative is available to discuss control technology options and how you can achieve the lowest possible emissions.

If at any time you need more information, please don't hesitate to contact your local Cleaver-Brooks representative.

CLASSIFIED OZONE NONATTAINMENT AREAS (JANUARY 1994)

ALABAMA(Region IV)

Birmingham, AL (Subpart 1)

Jefferson Co	[m*]
Shelby Co	[m*]

ARIZONA(Region IX)

Phoenix-Mesa, AZ (Subpart 1)

Maricopa Co (P)	[n*]
Pinal Co (P)	[*]

ARKANSAS(Region VI)

Memphis, TN-AR (Marginal)

Crittenden Co

CALIFORNIA(Region IX)

Amador and Calaveras Cos (Central Mtn), CA (Subpart 1)

Amador Co
Calaveras Co

Chico, CA (Subpart 1)

Butte Co	[n*]

Imperial Co, CA (Marginal)

Imperial Co	[n*]

Kern Co (Eastern Kern), CA (Subpart 1)

Kern Co (P)	[m*]

Los Angeles South Coast Air Basin, CA (Severe 17)

Los Angeles Co (P)	[n*]
Orange Co	[n*]
Riverside Co (P)	[n*]
San Bernardino Co (P)	[n*]

Los Angeles-San Bernardino Cos (W Mojave),CA (Moderate)

Los Angeles Co (P)	[n*]
San Bernardino Co (P)	[n*]

Mariposa and Tuolumne Cos (Southern Mtn),CA (Subpart 1)

Mariposa Co
Tuolumne Co

Nevada Co. (Western Part), CA (Subpart 1)

Nevada Co (P)

Riverside Co, (Coachella Valley), CA (Serious)

Riverside Co (P)	[n*]

Sacramento Metro, CA (Serious)

El Dorado Co (P)	[n*]
Placer Co (P)	[n*]
Sacramento Co	[n*]
Solano Co (P)	[n*]
Sutter Co (P)	[n*]
Yolo Co	[n*]

San Diego, CA (Subpart 1)

San Diego Co (P)	[m*]

San Francisco Bay Area, CA (Marginal)

Alameda Co	[n*]
Contra Costa Co	[n*]
Marin Co	[n*]
Napa Co	[n*]
San Francisco Co	[n*]
San Mateo Co	[n*]
Santa Clara Co	[n*]
Solano Co (P)	[n*]
Sonoma Co (P)	[n*]

San Joaquin Valley, CA (Serious)

Fresno Co	[n*]
Kern Co (P)	[n*]
Kings Co	[n*]
Madera Co	[n*]
Merced Co	[n*]
San Joaquin Co	[n*]
Stanislaus Co	[n*]
Tulare Co	[n*]

Sutter Co (Sutter Buttes), CA (Subpart 1)

Sutter Co (P)	[n*]

Ventura Co, CA (Moderate)

Ventura Co (P)	[n*]

That part of Ventura County excluding the Channel Islands of Anacapa and San Nicolas Islands.

COLORADO(Region VIII)

Denver-Boulder-Greeley-Ft Collins-Love., CO (Subpart 1 EAC)

Adams Co	[m*]
Arapahoe Co	[m*]
Boulder Co	[m*]
Broomfield Co	[m*]
Denver Co	[m*]
Douglas Co	[m*]
Jefferson Co	[m*]
Larimer Co (P)	[*]
Weld Co (P)	[*]

CONNECTICUT(Region I)

Greater Connecticut, CT (Moderate)

Hartford Co	[n*]
Litchfield Co	[n*]
New London Co	[n*]
Tolland Co	[n*]
Windham Co	[n*]

New York-N. New Jersey-Long Island,NY-NJ-CT (Moderate)

Fairfield Co	[n*]
Middlesex Co	[n*]
New Haven Co	[n*]

DELAWARE(Region III)

Philadelphia-Wilmin-Atlantic Ci,PA-NJ-MD-DE (Moderate)

Kent Co	[n*]
New Castle Co	[n*]
Sussex Co	[n*]

CLASSIFIED OZONE NONATTAINMENT AREAS (DATE ???)

DISTRICT OF COLUMBIA (Region III)

Washington, DC-MD-VA (Moderate)

Entire District [n*]

GEORGIA(Region IV)

Atlanta, GA (Marginal)

Barrow Co
Bartow Co
Carroll Co
Cherokee Co [n*]
Clayton Co [n*]
Cobb Co [n*]
Coweta Co [n*]
De Kalb Co [n*]
Douglas Co [n*]
Fayette Co [n*]
Forsyth Co [n*]
Fulton Co [n*]
Gwinnett Co [n*]
Hall Co
Henry Co [n*]
Newton Co
Paulding Co [n*]
Rockdale Co [n*]
Spalding Co
Walton Co

Chattanooga, TN-GA (Subpart 1 EAC)

Catoosa Co

Macon, GA (Subpart 1)

Bibb Co
Monroe Co (P)

Murray Co (Chattahoochee Nat Forest), GA (Subpart 1)

Murray Co (P)

ILLINOIS(Region V)

Chicago-Gary-Lake County, IL-IN (Moderate)

Cook Co [n*]
Du Page Co [n*]
Grundy Co (P) [n*]
Aux Sable Township,
Goose Lake Township
Kane Co [n*]
Kendall Co (P) [n*]
Oswego Township
Lake Co [n*]
Mc Henry Co [n*]
Will Co [n*]

St Louis, MO-IL (Moderate)

Jersey Co [m*]
Madison Co [m*]
Monroe Co [m*]
St Clair Co [m*]

INDIANA(Region V)

Chicago-Gary-Lake County, IL-IN (Moderate)

Lake Co [n*]
Porter Co [n*]

Cincinnati-Hamilton, OH-KY-IN (Subpart 1)

Dearborn Co (P)
Lawrenceburg Township

Evansville, IN (Subpart 1)

Vanderburgh Co [m*]
Warrick Co

Fort Wayne, IN (Subpart 1)

Allen Co

Greene Co, IN (Subpart 1)

Greene Co

Indianapolis, IN (Subpart 1)

Boone Co
Hancock Co
Hendricks Co
Johnson Co
Madison Co
Marion Co [m*]
Morgan Co
Shelby Co

Jackson Co, IN (Subpart 1)

Jackson Co

La Porte, IN (Marginal)

La Porte Co

Louisville, KY-IN (Subpart 1)

Clark Co [m*]
Floyd Co [m*]

Muncie, IN (Subpart 1)

Delaware Co

South Bend-Elkhart, IN (Subpart 1)

Elkhart Co [m*]
St Joseph Co [m*]

Terre Haute, IN (Subpart 1)

Vigo Co

KENTUCKY(Region IV)

Cincinnati-Hamilton, OH-KY-IN (Subpart 1)

Boone Co [m*]
Campbell Co [m*]
Kenton Co [m*]

Clarksville-Hopkinsville, TN-KY (Subpart 1)

Christian Co

Huntington-Ashland, WV-KY (Subpart 1)

Boyd Co [m*]

Louisville, KY-IN (Subpart 1)

Bullitt Co [m*]
Jefferson Co [m*]
Oldham Co [m*]

LOUISIANA(Region VI)

Baton Rouge, LA (Marginal)

Ascension Par [n*]

East Baton Rouge Par [n*]
Iberville Par [n*]
Livingston Par [n*]
West Baton Rouge Par [n*]

MAINE(Region I)

Hancock, Knox, Lincoln & Waldo Cos, ME (Subpart 1)

Hancock Co (P) [m*]
Knox Co (P) [n*]
Lincoln Co (P) [n*]
Waldo Co (P) [m*]

Portland, ME (Marginal)

Androscoggin Co (P) [n*]
Cumberland Co (P) [n*]
Sagadahoc Co [n*]
York Co (P) [n*]

MARYLAND(Region III)

Baltimore, MD (Moderate)

Anne Arundel Co [n*]
Baltimore (City) [n*]
Baltimore Co [n*]
Carroll Co [n*]
Harford Co [n*]
Howard Co [n*]

Kent and Queen Anne's Cos, MD (Marginal)

Kent Co [m*]
Queen Annes Co [m*]

Philadelphia-Wilmin-Atlantic Ci,PA-NJ-MD-DE (Moderate)

Cecil Co [n*]

Washington Co (Hagerstown), MD (Subpart 1 EAC)

Washington Co

Washington, DC-MD-VA (Moderate)

Calvert Co [n*]
Charles Co [n*]
Frederick Co [n*]
Montgomery Co [n*]
Prince George's Co [n*]

MASSACHUSETTS(Region I)

Boston-Lawrence-Worcester (E. MA), MA (Moderate)

Barnstable Co [n*]
Bristol Co [n*]
Dukes Co [n*]
Essex Co [n*]
Middlesex Co [n*]
Nantucket Co [n*]
Norfolk Co [n*]
Plymouth Co [n*]
Suffolk Co [n*]
Worcester Co [n*]

Springfield (Western MA), MA (Moderate)

Berkshire Co [n*]
Franklin Co [n*]
Hampden Co [n*]
Hampshire Co [n*]

MICHIGAN(Region V)

Allegan Co, MI (Subpart 1)

Allegan Co [m*]

Benton Harbor, MI (Subpart 1)

Berrien Co

Benzie Co, MI (Subpart 1)

Benzie Co

Cass Co, MI (Marginal)

Cass Co

Detroit-Ann Arbor, MI (Marginal)

Lenawee Co
Livingston Co [m*]
Macomb Co [m*]
Monroe Co [m*]
Oakland Co [m*]
St Clair Co [m*]
Washtenaw Co [m*]
Wayne Co [m*]

Flint, MI (Subpart 1)

Genesee Co [m*]
Lapeer Co

Grand Rapids, MI (Subpart 1)

Kent Co [m*]
Ottawa Co [m*]

Huron Co, MI (Subpart 1)

Huron Co

Kalamazoo-Battle Creek, MI (Subpart 1)

Calhoun Co
Kalamazoo Co
Van Buren Co

Lansing-East Lansing, MI (Subpart 1)

Clinton Co
Eaton Co
Ingham Co

Mason Co, MI (Subpart 1)

Mason Co

Muskegon, MI (Marginal)

Muskegon Co [m*]

MISSOURI(Region VII)

St Louis, MO-IL (Moderate)

Franklin Co [m*]
Jefferson Co [m*]
St Charles Co [m*]
St Louis [m*]
St Louis Co [m*]

Appendix A

CLASSIFIED OZONE NONATTAINMENT AREAS (DATE ???)

NEVADA(Region IX)

Las Vegas, NV (Subpart 1)

Clark Co (P) [*]

NEW HAMPSHIRE(Region I)

Boston-Manchester-Portsmouth(SE),NH (Moderate)

Hillsborough Co (P) [n*]
Merrimack Co (P) [n*]
Rockingham Co (P) [n*]
Strafford Co (P) [n*]

NEW JERSEY(Region II)

New York-N. New Jersey-Long Island,NY-NJ-CT (Moderate)

Bergen Co [n*]
Essex Co [n*]
Hudson Co [n*]
Hunterdon Co [n*]
Middlesex Co [n*]
Monmouth Co [n*]
Morris Co [n*]
Passaic Co [n*]
Somerset Co [n*]
Sussex Co [n*]
Union Co [n*]
Warren Co [n*]

Philadelphia-Wilmin-Atlantic Ci,PA-NJ-MD-DE (Moderate)

Atlantic Co [n*]
Burlington Co [n*]
Camden Co [n*]
Cape May Co [n*]
Cumberland Co [n*]
Gloucester Co [n*]
Mercer Co [n*]
Ocean Co [n*]
Salem Co [n*]

NEW YORK(Region II)

Albany-Schenectady-Troy, NY (Subpart 1)

Albany Co [n*]
Greene Co [n*]
Montgomery Co [n*]
Rensselaer Co [n*]
Saratoga Co [n*]
Schenectady Co [n*]
Schoharie Co

Buffalo-Niagara Falls, NY (Subpart 1)

Erie Co [n*]
Niagara Co [n*]

Essex Co (Whiteface Mtn), NY (Subpart 1)

Essex Co (P) [n*]

Jamestown, NY (Subpart 1)

Chautauqua Co

Jefferson Co, NY (Moderate)

Jefferson Co [n*]

New York-N. New Jersey-Long Island,NY-NJ-CT (Moderate)

Bronx Co [n*]
Kings Co [n*]
Nassau Co [n*]
New York Co [n*]
Queens Co [n*]
Richmond Co [n*]
Rockland Co [n*]
Suffolk Co [n*]
Westchester Co [n*]

Poughkeepsie, NY (Moderate)

Dutchess Co [n*]
Orange Co [n*]
Putnam Co [n*]

Rochester, NY (Subpart 1)

Genesee Co
Livingston Co
Monroe Co
Ontario Co
Orleans Co
Wayne Co

NORTH CAROLINA(Region IV)

Charlotte-Gastonia-Rock Hill, NC-SC (Moderate)

Cabarrus Co
Gaston Co [m*]
Iredell Co (P)
Davidson Township Coddle Creek Township
Lincoln Co
Mecklenburg Co [m*]
Rowan Co
Union Co

Fayetteville, NC (Subpart 1 EAC)

Cumberland Co

Greensboro-Winston Salem-High Point, NC (Marginal EAC)

Alamance Co
Caswell Co
Davidson Co [m*]
Davie Co [m*]
Forsyth Co [m*]
Guilford Co [m*]
Randolph Co
Rockingham Co

Haywood and Swain Cos (Great Smoky NP), NC (Subpart 1)

Haywood Co (P)
Great Smoky Mountain National Park
Swain Co (P)
Great Smoky Mountain National Park

Hickory-Morganton-Lenoir, NC (Subpart 1 EAC)

Alexander Co	
Burke Co (P)	
Unifour Metropolitan Planning Organization Boundary	
Caldwell Co (P)	
Unifour Metropolitan Planning Organization Boundary	
Catawba Co	

Raleigh-Durham-Chapel Hill, NC (Subpart 1)

Chatham Co (P)	
Baldwin Township, Center Township, New Hope Township, Williams Township	
Durham Co	[m*]
Franklin Co	
Granville Co	[m*]
Johnston Co	
Orange Co	
Person Co	
Wake Co	[m*]

Rocky Mount, NC (Subpart 1)

Edgecombe Co	
Nash Co	

OHIO(Region V)

Canton-Massillon, OH (Subpart 1)

Stark Co	[m*]

Cincinnati-Hamilton, OH-KY-IN (Subpart 1)

Butler Co	[n*]
Clermont Co	[n*]
Clinton Co	[m*]
Hamilton Co	[n*]
Warren Co	[n*]

Cleveland-Akron-Lorain, OH (Moderate)

Ashtabula Co	[m*]
Cuyahoga Co	[m*]
Geauga Co	[m*]
Lake Co	[m*]
Lorain Co	[m*]
Medina Co	[m*]
Portage Co	[m*]
Summit Co	[m*]

Columbus, OH (Subpart 1)

Delaware Co	[m*]
Fairfield Co	
Franklin Co	[m*]
Knox Co	
Licking Co	[m*]
Madison Co	

Dayton-Springfield, OH (Subpart 1)

Clark Co	[m*]
Greene Co	[m*]
Miami Co	[m*]
Montgomery Co	[m*]

Lima, OH (Subpart 1)

Allen Co	

Parkersburg-Marietta, WV-OH (Subpart 1)

Washington Co

Steubenville-Weirton, OH-WV (Subpart 1)

Jefferson Co	[m*]

Toledo, OH (Subpart 1)

Lucas Co	[m*]
Wood Co	[m*]

Wheeling, WV-OH (Subpart 1)

Belmont Co	

Youngstown-Warren-Sharon, OH-PA (Subpart 1)

Columbiana Co	[m*]
Mahoning Co	[m*]
Trumbull Co	[m*]

PENNSYLVANIA(Region III)

Allentown-Bethlehem-Easton, PA (Subpart 1)

Carbon Co	[n*]
Lehigh Co	[n*]
Northampton Co	[n*]

Altoona, PA (Subpart 1)

Blair Co	[n*]

Clearfield and Indiana Cos, PA (Subpart 1)

Clearfield Co	
Indiana Co	

Erie, PA (Subpart 1)

Erie Co	[n*]

Franklin Co, PA (Subpart 1)

Franklin Co	[n*]

Greene Co, PA (Subpart 1)

Greene Co	[n*]

Harrisburg-Lebanon-Carlisle, PA (Subpart 1)

Cumberland Co	[n*]
Dauphin Co	[n*]
Lebanon Co	[n*]
Perry Co	[n*]

Johnstown, PA (Subpart 1)

Cambria Co	[n*]

Lancaster, PA **(Marginal)**

Lancaster Co	[n*]

CLASSIFIED OZONE NONATTAINMENT AREAS (DATE ???)

Philadelphia-Wilmin-Atlantic Ci,PA-NJ-MD-DE (Moderate)

Bucks Co	[n*]
Chester Co	[n*]
Delaware Co	[n*]
Montgomery Co	[n*]
Philadelphia Co	[n*]

Pittsburgh-Beaver Valley, PA (Subpart 1)

Allegheny Co	[m*]
Armstrong Co	[m*]
Beaver Co	[m*]
Butler Co	[m*]
Fayette Co	[m*]
Washington Co	[m*]
Westmoreland Co	[m*]

Reading, PA (Subpart 1)

Berks Co	[m*]

Scranton-Wilkes-Barre, PA (Subpart 1)

Lackawanna Co	[n*]
Luzerne Co	[n*]
Monroe Co	[n*]
Wyoming Co	[n*]

State College, PA (Subpart 1)

Centre Co

Tioga Co, PA (Subpart 1)

Tioga Co

York, PA (Subpart 1)

Adams Co	[n*]
York Co	[n*]

Youngstown-Warren-Sharon, OH-PA (Subpart 1)

Mercer Co	[n*]

RHODE ISLAND(Region I)

Providence (All RI), RI (Moderate)

Bristol Co	[n*]
Kent Co	[n*]
Newport Co	[n*]
Providence Co	[n*]
Washington Co	[n*]

SOUTH CAROLINA(Region IV)

Charlotte-Gastonia-Rock Hill, NC-SC (Moderate)

York Co (P)
Portion along MPO lines

Columbia, SC (Subpart 1 EAC)

Lexington Co (P)
Richland Co (P)

Greenville-Spartanburg-Anderson, SC (Subpart 1 EAC)

Anderson Co
Greenville Co
Spartanburg Co

TENNESSEE(Region IV)

Chattanooga, TN-GA (Subpart 1 EAC)

Hamilton Co
Meigs Co

Clarksville-Hopkinsville, TN-KY (Subpart 1)

Montgomery Co

Johnson City-Kingsport-Bristol, TN (Subpart 1 EAC)

Hawkins Co
Sullivan Co

Knoxville, TN (Subpart 1)

Anderson Co	
Blount Co	
Cocke Co (P) (Great Smoky Mtn Park)	
Jefferson Co	
Knox Co	[m*]
Loudon Co	
Sevier Co	

Memphis, TN-AR (Marginal)

Shelby Co	[m*]

Nashville, TN (Subpart 1 EAC)

Davidson Co	[m*]
Rutherford Co	[m*]
Sumner Co	[m*]
Williamson Co	[m*]
Wilson Co	[m*]

TEXAS(Region VI)

Beaumont-Port Arthur, TX (Marginal)

Hardin Co	[n*]
Jefferson Co	[n*]
Orange Co	[n*]

Dallas-Fort Worth, TX (Moderate)

Collin Co	[n*]
Dallas Co	[n*]
Denton Co	[n*]
Ellis Co	
Johnson Co	
Parker Co	
Rockwall Co	
Tarrant Co	[n*]

Houston-Galveston-Brazoria, TX (Moderate)

Brazoria Co	[n*]
Chambers Co	[n*]
Fort Bend Co	[n*]
Galveston Co	[n*]
Harris Co	[n*]
Liberty Co	[n*]
Montgomery Co	[n*]
Waller Co	[n*]

San Antonio, TX (Subpart 1 EAC)

Bexar Co
Comal Co
Guadalupe Co

VIRGINIA(Region III)

Frederick Co, VA (Subpart 1 EAC)

Frederick Co
Winchester

Fredericksburg, VA (Moderate)

Fredericksburg
Spotsylvania Co
Stafford [n*]

Madison and Page Cos (Shenandoah NP), VA (Subpart 1

Madison Co (P)
Page Co (P)

Norfolk-Virginia Beach-Newport News (HR),VA (Marginal)

Chesapeake [m*]
Gloucester Co
Hampton [m*]
Isle Of Wight Co
James City Co [m*]
Newport News [m*]
Norfolk [m*]
Poquoson [m*]
Portsmouth [m*]
Suffolk [m*]
Virginia Beach [m*]
Williamsburg [m*]
York Co [m*]

Richmond-Petersburg, VA (Marginal)

Charles City Co [m*]
Chesterfield Co [m*]
Colonial Heights [m*]
Hanover Co [m*]
Henrico Co [m*]
Hopewell [m*]
Petersburg
Prince George Co
Richmond [m*]

Roanoke, VA (Subpart 1 EAC)

Botetourt Co
Roanoke
Roanoke Co
Salem

Washington, DC-MD-VA (Moderate)

Alexandria [n*]
Arlington Co [n*]
Fairfax [n*]
Fairfax Co [n*]
Falls Church [n*]
Loudoun Co [n*]
Manassas [n*]
Manassas Park [n*]
Prince William Co [n*]

WEST VIRGINIA(Region III)

Berkeley and Jefferson Counties, WV (Subpart 1 EAC)

Berkeley Co
Jefferson Co

Charleston, WV (Subpart 1)

Kanawha Co [m*]
Putnam Co [m*]

Huntington-Ashland, WV-KY (Subpart 1)

Cabell Co [m*]
Wayne Co [m*]

Parkersburg-Marietta, WV-OH (Subpart 1)

Wood Co [m*]

Steubenville-Weirton, OH-WV (Subpart 1)

Brooke Co [*]
Hancock Co [*]

Wheeling, WV-OH (Subpart 1)

Marshall Co
Ohio Co

WISCONSIN(Region V)

Door Co, WI (Subpart 1)

Door Co [m*]

Kewaunee Co, WI (Subpart 1)

Kewaunee Co [m*]

Manitowoc Co, WI (Subpart 1)

Manitowoc Co [m*]

Milwaukee-Racine, WI (Moderate)

Kenosha Co [n*]
Milwaukee Co [n*]
Ozaukee Co [n*]
Racine Co [n*]
Washington Co [n*]
Waukesha Co [n*]

Sheboygan, WI (Moderate)

Sheboygan Co [m*]

Key

n = county in current 1-hr Ozone Non-attainment area

m = county in current 1-hr Ozone Maintenance area

P = a portion of the county is located within the area

*** = county in 1-Hr Ozone, CO or PM-10 non-attainment or maintenance area**

CLASSIFIED CARBON MONOXIDE NONATTAINMENT AREAS (JANUARY 1994)

Alaska	
Anchorage	Moderate>12.7 ppm
Fairbanks	Moderate≤12.7 ppm
Arizona	
Phoenix	Moderate≤12.7 ppm
California	
Chico	Moderate≤12.7 ppm
Fresno	Moderate>12.7 ppm
Lake Tahoe South Shore	Moderate≤12.7 ppm
Los Angeles South Coast Air Basin	Serious
Modesto	Moderate≤12.7 ppm
Sacramento	Moderate≤12.7 ppm
San Diego	Moderate≤12.7 ppm
San Francisco – Oakland – San Jose	Moderate≤12.7 ppm
Stockton	Moderate≤12.7 ppm
Colorado	
Colorado Springs	Moderate≤12.7 ppm
Denver – Boulder	Moderate>12.7 ppm
Fort Collins	Moderate≤12.7 ppm
Longmont	Moderate≤12.7 ppm
Connecticut	
Hartford – New Britain - Middletown	Moderate≤12.7 ppm
New York – N. New Jersey – Long Island Parts of Fairfield and Litchfield Counties	Moderate>12.7 ppm
District of Columbia	
Entire District	Moderate≤12.7 ppm
Maryland	
Baltimore	Moderate≤12.7 ppm
Washington D.C. Montgomery and Prince George's Counties	Moderate≤12.7 ppm
Massachusetts	
Boston	Moderate≤12.7 ppm
Minnesota	
Duluth	Moderate≤12.7 ppm
Minneapolis – St. Paul	Moderate≤12.7 ppm
Montana	
Missoula	Moderate≤12.7 ppm
Nevada	
Las Vegas	Moderate>12.7 ppm
Reno	Moderate≤12.7 ppm
New Jersey	
N. New Jersey – New York – Long Island	Moderate>12.7 ppm
Camden County – Philadelphia	Moderate≤12.7 ppm
New Mexico	
Albuquerque	Moderate≤12.7 ppm
New York	
New York – N. New Jersey – Long Island	Moderate>12.7 ppm
Syracuse	Moderate≤12.7 ppm
North Carolina	
Raleigh – Durham	Moderate≤12.7 ppm
Winston – Salem	Moderate≤12.7 ppm
Ohio	
Cleveland	Moderate≤12.7 ppm
Oregon	
Grants Pass	Moderate≤12.7 ppm
Klamath Falls	Moderate≤12.7 ppm
Medford	Moderate≤12.7 ppm
Portland – Vancouver	Moderate≤12.7 ppm
Pennsylvania	
Philadelphia – Camden County	Moderate≤12.7 ppm
Tennessee	
Memphis	Moderate≤12.7 ppm
Texas	
El Paso	Moderate≤12.7 ppm
Utah	
Ogden	Moderate≤12.7 ppm
Provo	Moderate>12.7 ppm
Virginia	
Washington D.C. Alexandria City, Arlington County	Moderate≤12.7 ppm
Washington	
Vancouver – Portland	Moderate≤12.7 ppm
Seattle – Tacoma	Moderate>12.7 ppm
Spokane	Moderate>12.7 ppm

NOTE: If there is no listing for a state, there are no classified carbon monoxide nonattainment areas located in the state.

CLASSIFIED PM_{10} NONATTAINMENT AREAS (JANUARY 1994)

Arizona
- Ajo
- Douglas
- Hayden/Miami
- Nogalas
- Paul Spur
- Phoenix
- Rillito
- Yuma

Arkansas
- Eagle River
- Juneau

California
- Coachella Valley
- Imperial Valley
- Mammoth Lake
- Owens Valley
- San Joaquin Valley
- Searles Valley
- South Coast Basin

Colorado
- Aspen
- Canon City
- Denver Metro
- Lamar
- Pagosa Springs
- Telluride

Connecticut
- New Haven

Idaho
- Boise
- Bonner County
- Pinehurst
- Pocatello

Illinois
- Granite City
- Lyons Township, McCook
- Oglesby
- Southeast Chicago

Indiana
- Lake County
- Vermillion County

Maine
- Presque Isle

Michigan
- Detroit

Minnesota
- Rochester
- St. Paul

Montana
- Butte
- Columbia
- Kalispell
- Lame Deer
- Libby
- Missoula
- Polson
- Ronan

Nevada
- Las Vegas
- Reno

New Mexico
- Anthony

Ohio
- Cuyahoga County
- Mingo Junction

Oregon
- Grant Pass
- Klamath Falls
- La Grand
- Medford
- Springfield/Eugene

Pennsylvania
- Clairton

Texas
- El Paso

Utah
- Salt Lake County
- Utah County

Washington
- Kent
- Olympia/Tumwater/Lacey
- Seattle Spokane
- Tacoma
- Wallula
- Yakima

West Virginia
- Follansbee

Wyoming
- Sheridan

NOTE: If there is no listing for a state, there are no classified PM-10 nonattainment areas located in the state.

CLASSIFIED SULFUR DIOXIDE NONATTAINMENT AREAS (JANUARY 1994)

Alabama
- Colbert Co.
- Lauderdale Co.

Arizona
- Cochise Co. (Douglas)
- Gila Co. (Miami/Globe)
- Greenlee Co. (Morenci)
- Pima Co. (Ajo)
- Pinal Co. (Hayden)
- Pinal Co. (San Manual)

Illinois
- Peoria Co.
- Tazwell Co.

Indiana
- Lake Co.
- Laporte Co.
- Marion Co.
- Vigo Co.
- Wayne Co.

Kentucky
- Boyd Co.
- Muhlenberg Co.

Maine
- Penobscot Co.
- Millinocket

Minnesota
- Minneapolis-St. Paul.
- Olmsted Co. (Rochester)

Montana
- Lewis and Clark Co.
- Yellowstone Co. (Laurel)

New Jersey
- **Warren Co.**

New Mexico
- Grant Co.

Nevada
- White Pine Co.

Ohio
- Coshocton Co.
- Cuyahoga Co. (part)
- Gallia Co. (Addison Twnshp.)
- Jefferson Co. (part)
- Lake Co. (part)
- Lorrain Co. (part)
- Lucas Co. (part)
- Morgan Co. (Center Twnshp.)
- Washington Co.

Pennsylvaina
- Allegheny Co.
- Armstrong Co.
- Warren Co.

Tennessee
- Benton Co.
- Humphreys Co.
- Polk Co.

Utah
- Salt Lake Co.
- Tooele Co. (part)

Wisconsin
- Brown Co. (Green Bay)
- Dane Co. (Madison)
- Marathon Co. (Rothschild)
- Milwaukee Co. (Milwaukee)
- Oneida Co. (Rhinelander)

West Virginia
- Hancock Co. (part)

NOTE: **If there is no listing for a state, there are no classified SO_2 nonattainment areas located in the state.**

AP-42
Uncontrolled Emission Factors for Propane Combustion

lb/MMBtu

Boiler Type	Particulate Matter (lb/MMBtu)	Sulfur Dioxide (lb/MMBtu)	Carbon Monoxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Volatile Organic Compounds: Nonmethane (lb/MMBtu)	Volatile Organic Compounds: Methane (lb/MMBtu)
Industrial	0.00098-0.0048	0.812 (%S)	0.034	0.136	0.0027	0.003
Commercial	0.00098-0.0048	0.812 (%S)	0.02	0.096	0.005	0.0026

ppm

Boiler Type	Particulate Matter (ppm)	Sulfur Dioxide (ppm)	Carbon Monoxide (ppm)	Nitrogen Oxides (ppm)	Volatile Organic Compounds: Nonmethane (ppm)	Volatile Organic Compounds: Methane (ppm)
Industrial	N/A	475 (%S)	45	111	6.8	7.5
Commercial	N/A	475 (%S)	27	78	12.5	6.5

Notes:
Estimated HHV of Propane: 91,500 Btu/gal

Industrial Boilers: 10-100 MMBtu/hr
Commercial Boilers: 0.5-10 MMBtu/hr

AP-42
Uncontrolled Emission Factors for Natural Gas Combustion

lb/MMBtu

Boiler Type	Particulate Matter (lb/MMBtu)	Sulfur Dioxide (lb/MMBtu)	Carbon Monoxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Volatile Organic Compounds: Nonmethane (lb/MMBtu)	Volatile Organic Compounds: Methane (lb/MMBtu)
Industrial	0.00095-0.0048	0.00057	0.033	0.133	0.0027	0.0029
Commercial	0.00095-0.0048	0.00057	0.019	0.095	0.005	0.0023

ppm

Boiler Type	Particulate Matter (ppm)	Sulfur Dioxide (ppm)	Carbon Monoxide (ppm)	Nitrogen Oxides (ppm)	Volatile Organic Compounds: Nonmethane (ppm)	Volatile Organic Compounds: Methane (ppm)
Industrial	N/A	0.34	46	112	6.8	7.3
Commercial	N/A	0.34	26	80	13	5.8

Notes:
Estimated HHV of Natural Gas: 1050 Btu/FT^3

Industrial Boilers: 10-100 MMBtu/hr
Commercial Boilers: 0.5-10 MMBtu/hr

AP-42
Uncontrolled Emission Factors for Fuel Oil Combustion

lb/MMBtu

Boiler Type	Particulate Matter (lb/MMBtu)	Sulfur Dioxide (lb/MMBtu)	Sulfur Trioxide (lb/MMBtu)	Carbon Monoxide (lb/MMBtu)	Nitrogen Oxides (lb/MMBtu)	Volatile Organic Compounds: Nonmethane (lb/MMBtu)	Volatile Organic Compounds: Methane (lb/MMBtu)
Industrial:							
Residual	0.0649(%S) + 0.0195	1.02(%S)	0.013(%S)	0.0325	0.357*	0.0018	0.0065
Distillate	0.0143	1.01(%S)	0.013(%S)	0.0325	0.143	0.0014	0.0004
Commercial:							
Residual	0.0649(%S) + 0.0195	1.02(%S)	0.013(%S)	0.0325	0.357*	0.0073	0.0031
Distillate	0.0143	1.01(%S)	0.013(%S)	0.0325	0.143	0.00124	0.0015

*Nitrogen oxide emissions from residual oil combustion in industrial and commercial boilers are strongly related to fuel nitrogen content.

The emissions can be more accurately predicted by the empirical relationship:

2.6(%N) ^ 2+0.143 lb/MMBtu (%N in fuel <0.5%)

For residual oils having nitrogen content (>0.5%) use 0.779 lb/MMBtu as an emission factor.

Notes:

Estimated HHV of #2 Oil: 140,000 Btu/gal

Estimated HHV of #6 Oil: 154,000 Btu/gal

Industrial Boilers: 10 - 100 MMBtu/hr

Commercial Boilers: 0.5 - 10 MMBtu/hr

AP-42
Uncontrolled Emission Factors for Fuel Oil Combustion

ppm

Boiler Type	Particulate Matter (ppm)	Sulfur Dioxide (ppm)	Sulfur Trioxide (ppm)	Carbon Monoxide (ppm)	Nitrogen Oxide (ppm)	Volatile Organic Compounds: Nonmethane (ppm)	Volatile Organic Compounds: Methane (ppm)
Industrial:							
Residual	N/A	549(%S)	7(%S)	42	273*	3.6	13
Distillate	N/A	544(%S)	7(%S)	42	107	2.8	0.8
Commercial:							
Residual	N/A	549(%S)	7(%S)	42	273*	14.6	6.2
Distillate	N/A	544(%S)	7(%S)	42	107	4.8	3

*Nitrogen oxide emissions from residual oil combustion in industrial and commercial boilers are strongly related to fuel nitrogen content.

The emissions can be more accurately predicted by the empirical relationship:

1,940(%N) ^ 2+107 ppm (%N in fuel <0.5%)

For residual oils having nitrogen content (>0.5%) use 595 ppm as an emission factor.

Notes:

Estimated HHV of #2 Oil: 140,000 Btu/gal

Estimated HHV of #6 Oil: 154,000 Btu/gal

Industrial Boilers: 10 - 100 MMBtu/hr

Commercial Boilers: 0.5 - 10 MMBtu/hr

EPA REGIONAL AIR QUALITY DIVISIONS

REGION 1

Boston, MA 617/565-3800
Maine, Vermont, New Hampshire, Connecticut, Massachusetts, Rhode Island

REGION 2

New York, NY 212/264-2301
New York, New Jersey, Puerto Rico, U.S. Virgin Islands

REGION 3

Philadelphia, PA 215/597-9390
Pennsylvania, Delaware, Virginia, West Virginia, Maryland, District of Columbia

REGION 4

Atlanta, GA 404/347-3043
Georgia, Florida, Alabama, North Carolina, South Carolina, Kentucky Tennessee, Mississippi

REGION 5

Chicago, IL 312/353-2212
Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin

REGION 6

Dallas, TX 214/655-7200
Texas, Arkansas, Oklahoma, Louisiana, New Mexico

REGION 7

Kansas City, MO 913/551-7020
Nebraska, Iowa, Kansas, Missouri

REGION 8

Denver, CO 303/293-1438
Colorado, Utah, Wyoming, Montana, North Dakota, South Dakota

REGION 9

San Francisco, CA 414/744-1219
California, Arizona, Nevada, Hawaii, American Samoa, Guam, Trust Territories of the Pacific

REGION 10

Seattle, WA 206/422-4152
Washington, Oregon, Idaho, Alaska

ACRONYMS/DEFINITIONS

ABMA American Boiler Manufacturer's Association
A group of manufacturer's representing the boiler industry of which Cleaver-Brooks is a member

APCD Air Pollution Control District
Usually refers to a local air quality agency controlling pollution in a given district

AQCR Air Quality Control Region
Generally refers to one of the ten EPA regional offices throughout the U.S.

AQMD Air Quality Management District
Refers to an area or region where air quality is regulated by a local agency

ARAC Acid Rain Advisory Committee
A committee established by the EPA to focus efforts on the various aspects of Title IV (Acid Deposition Control) of the Clean Air Act

ARB Air Resource Board
An air quality agency usually responsible for pollution control at the state level

BACT Best Available Control Technology
An emission limitation based on the maximum degree of reduction, which the permitting authority has determined is achievable and cost effective

BARCT Best Available Retrofit Control Technology
A retrofit equipment emission limitation based on the BACT principles - but developed for retrofitting existing equipment

CEM Continuous Emission Monitoring
An emission monitoring system used for measuring emission levels without interruption - required in many local districts and NSPS for certain applications

CFR Code of Federal Regulations
A codification of the rules published in the Federal Register by the departments and agencies of the Federal Government

EPA Environmental Protection Agency
A federal agency responsible for pollution control at the national level

ESP Electrostatic Precipitators
Emission control equipment used to control particulate matter on large utility boilers

FGD Flue Gas Desulfurization
Emission control method used to control sulfur dioxide emissions

FGR Flue Gas Recirculation
NO_x emission control technique - involves returning a portion of the flue gases to the combustion zone

LAER Lowest Achievable Emission Rate
The most stringent emission limitation contained in any SIP or achieved in practice for a given class of equipment

MACT Maximum Available Control Technology
Emission standard requiring the maximum degree of emission reduction that has been demonstrated achievable

NAAQS National Ambient Air Quality Standards
EPA established air quality standards for ambient outdoor emission levels

NESHAP National Emission Standards for Hazardous Air Pollutants
Standards established by the EPA for regulation of air toxins

NSPS New Source Performance Standards
Regulations established by the EPA for emissions from equipment, including boilers. Many state regulations are more stringent than the NSPS

NSR New Source Review
A review performed during the permitting process for a new major installation in a nonattainment area

PSD Prevention of Significant Deterioration
A review performed during the permitting process for a new major installation in an attainment area

RACT Reasonably Available Control Technology
A set of recommended levels of emission controls applicable to specific sources or categories located in nonattainment areas

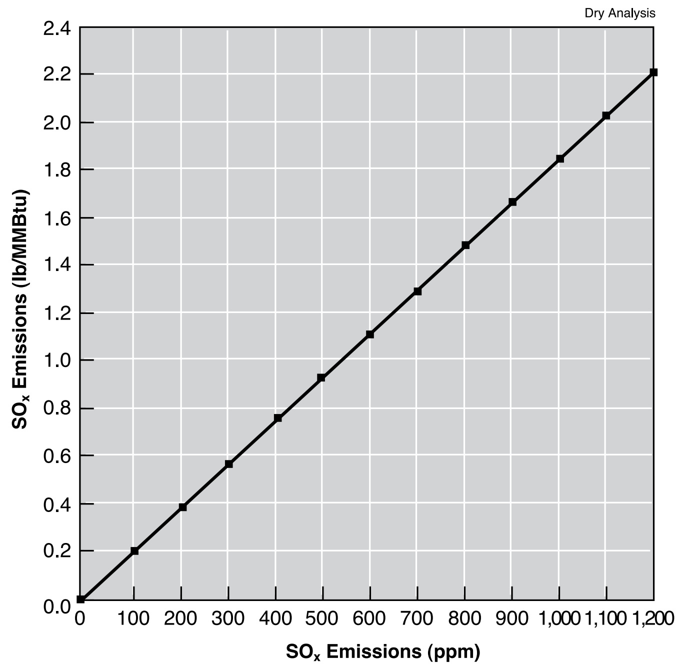
SCAQMD South Coast Air Quality Management District
The air pollution control agency for the Los Angeles, CA area - emission regulations enacted in this district generally set the trends for other local regulations throughout the U.S.

SCR Selective Catalytic Reduction
A NO_x control method in which ammonia or urea is injected into the exhaust gases in the presence of a catalyst

SIP State Implementation Plan
An EPA approved emission control plan to attain or maintain NAAQS

SNCR Selective Non-Catalytic Reduction
A NO_x control method where ammonia or urea is injected into the stack and where the exhaust gases are approximately 1600 degrees Fahrenheit

SO_x Emissions Conversion Curves
15% Excess Air (3% O_2)

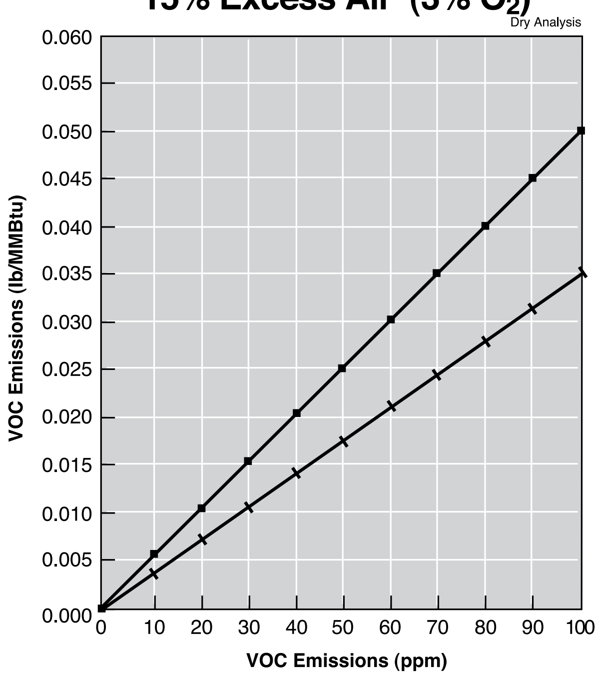


Conversion Equations

#2 and #6 Oil:
ppm = (lb/MMBtu)*540
lb/MMBtu = (ppm)/540

#2 and #6 Oil

Volatile Organic Compound Conversion Curves
15% Excess Air (3% O_2)



Conversion Equations

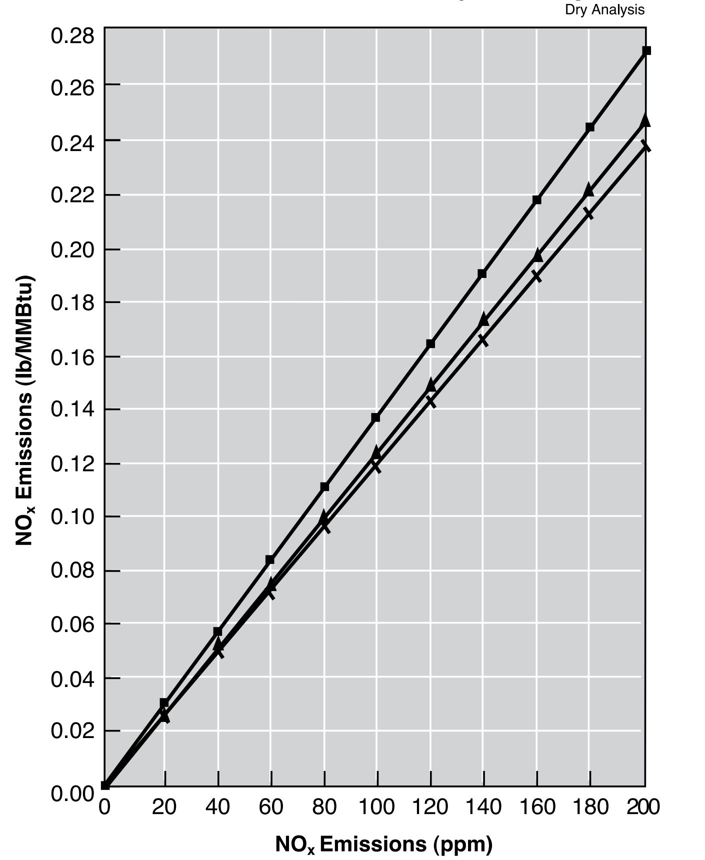
#2 and #6 Oil:
ppm = (lb/MMBtu)*2000
lb/MMBtu = (ppm)/2000

Natural Gas and Propane:
ppm = (lb/MMBtu)*2500
lb/MMBtu = (ppm)/2500

#2 and #6 Oil
Natural Gas and Propane

NO_x Emissions Conversion Curves
15% Excess Air (3% O_2)

Dry Analysis



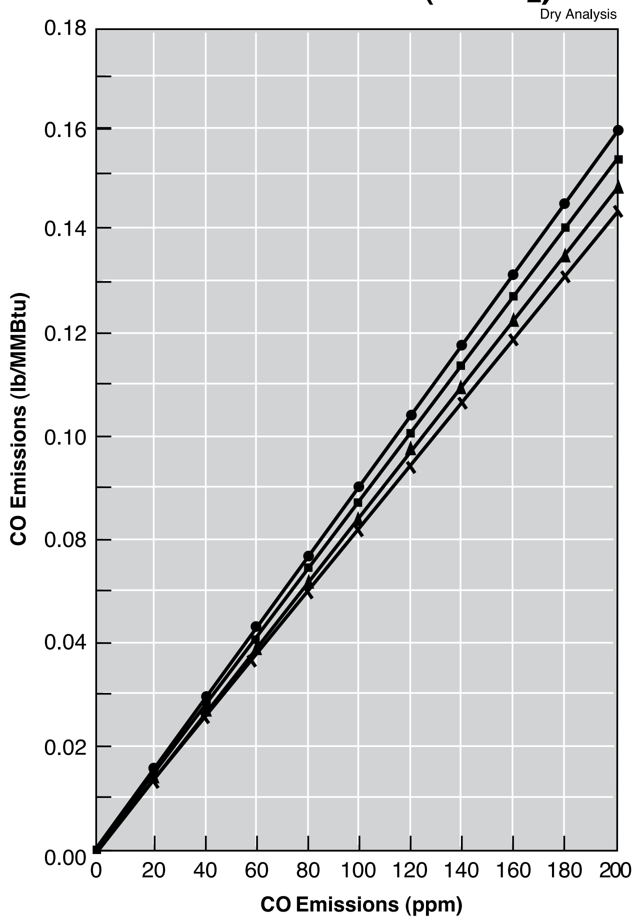
Conversion Equations

#2 and #6 Oil:
ppm = (lb/MMBtu)*750
lb/MMBtu = (ppm)/750

Natural Gas:
ppm = (lb/MMBtu)*850
lb/MMBtu = (ppm)/850

Propane:
ppm = (lb/MMBtu)*810
lb/MMBtu = (ppm)/810

CO Emissions Conversion Curves
15% Excess Air (3% O_2)



Conversion Equations

#2 Oil:
ppm = (lb/MMBtu)*1290
lb/MMBtu = (ppm)/1290

Natural Gas:
ppm = (lb/MMBtu)*1370
lb/MMBtu = (ppm)/1370

#6 Oil:
ppm = (lb/MMBtu)*1260
lb/MMBtu = (ppm)/1260

Propane:
ppm = (lb/MMBtu)*1340
lb/MMBtu = (ppm)/1340

Correcting Emission Readings to 3% Oxygen

$$\text{ppm (@3\%)} = \frac{21 - 3}{21 - O_2 \text{ (actual)}} \times \text{ppm (actual)}$$

Example: What is the NO_x level corrected to 3% oxygen for a measured level of 12 ppm at 7.1% oxygen?

$$\text{ppm (@3\%)} = \frac{21 - 3}{21 - 7.1} \times 12 = 15.5 \text{ ppm } NO_x$$

Appendix F

CALCULATION OF ANNUAL EMISSIONS FOR INDUSTRIAL BOILERS

Many provisions of the 1990 Clean Air Act Amendments assess the impact of pollution sources based on the potential annual emissions (usually expressed as tons per year, or tpy). When addressing industrial boilers, the potential annual emissions of NO_x are of concern and frequently must be calculated. Following is an example of how to calculate the potential annual NO_x emissions for industrial boilers.

To determine the annual NO_x emissions for an industrial boiler, three items must be known:

1. The NO_x emission factor for the boiler.
2. The maximum rated input for the boiler.
3. The maximum allowable hours of operation for the boiler.

Once the information above is obtained, the following equation can be used to determine annual emissions.

$$\text{Boiler Input} \times \text{Emission Factor} \times \text{Annual Hours of Operation} = \text{Total Annual Emissions}$$

For example, the calculation of the total annual NOx emissions for an 800 hp boiler operating 24 hours/day, 365 days/year and having a NO_x level of 110 ppm would be as follows.

Boiler Input = 33.5 MMBtu/hr (Based on 80% Efficiency)
Emission Factor = 0.13 lb/MMBtu (110 ppm = 0.13 lb/MMBtu)
Annual Hours of Operation = 8760 hours/year (24 hours/day x 365 days/year)

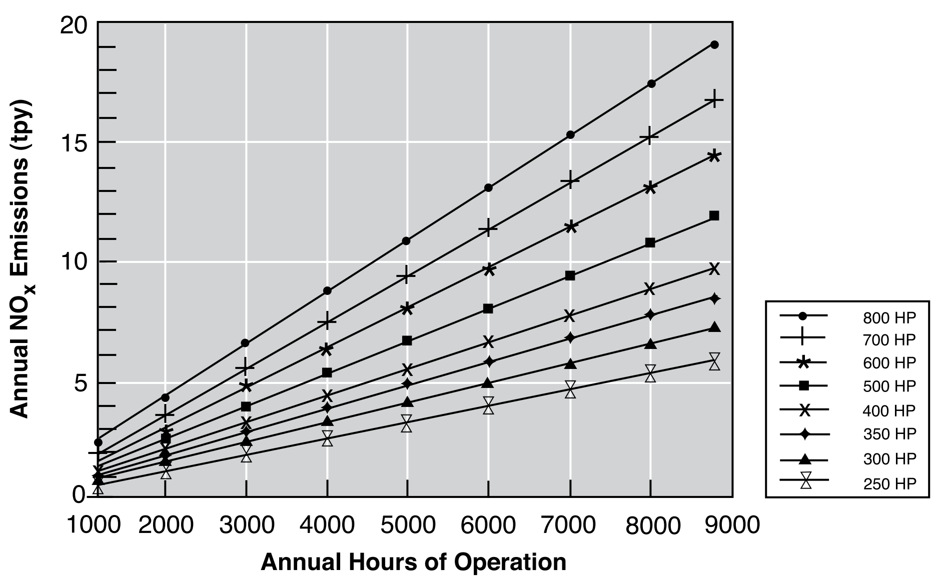
Substituting this data into the equation above yields:

$$\frac{0.13 \text{ lb } NO_x}{\text{MMBtu}} \times \frac{33.5 \text{ MMBtu}}{\text{hr}} \times \frac{8760 \text{ hrs}}{\text{year}} \times \frac{1 \text{ ton}}{2000\text{lb}} = 19.1 \text{ tpy } NO_x$$

The annual NO_x emissions for this specific boiler is 19.1 tpy.

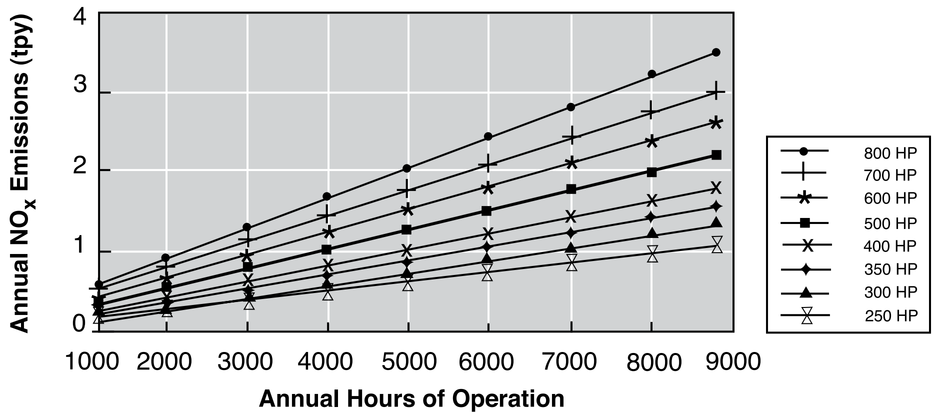
The following graphs indicate the annual NO_x emissions for boiler sizes 250-800 horsepower firing natural gas at maximum input operating 24 hours/day, 365 days/year. There are for NO_x emission levels of 110, 60, 30, 25, and 20 ppm.

Annual NO_x Emissions for 250-800 Horsepower Boilers NO_x = 110 ppm*



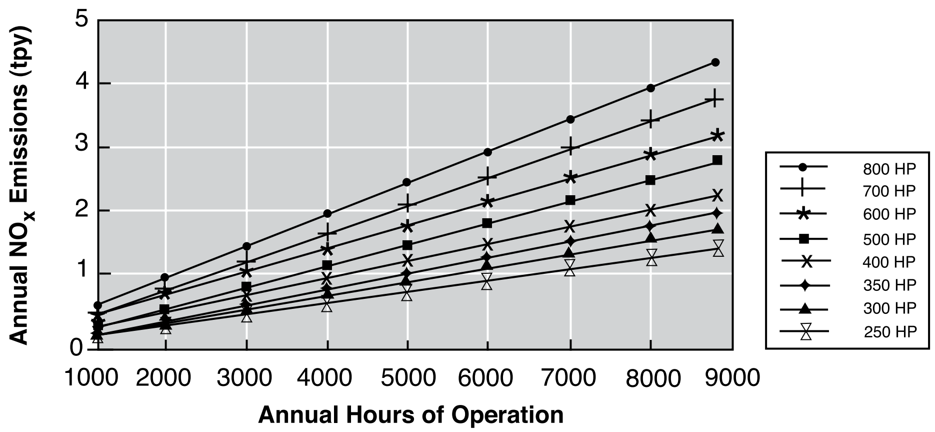
Efficiency = 80%
*ppm corrected to 3% oxygen

Annual NO_X Emissions for 250-800 Horsepower Boilers NO_X = 20 ppm*



Efficiency = 80%
*ppm corrected to 3% oxygen

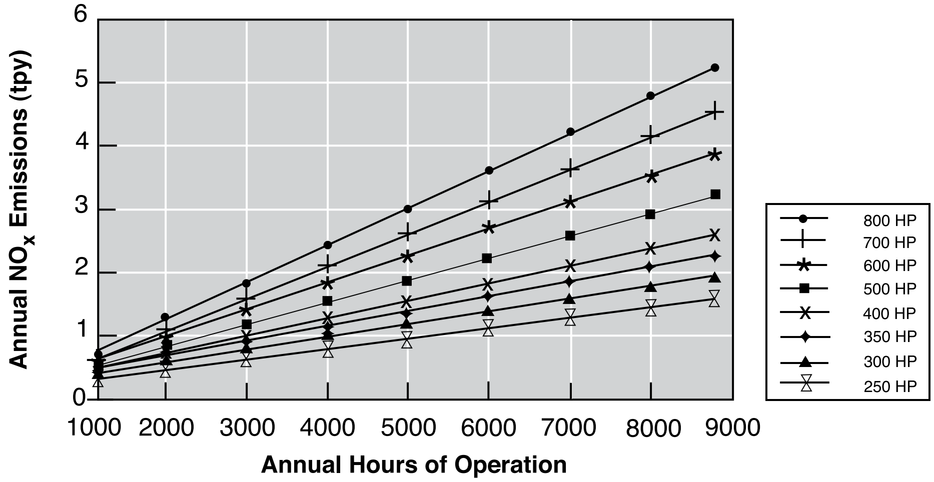
Annual NO_X Emissions for 250-800 Horsepower Boilers NO_X = 25 ppm*



Efficiency = 80%
*ppm corrected to 3% oxygen

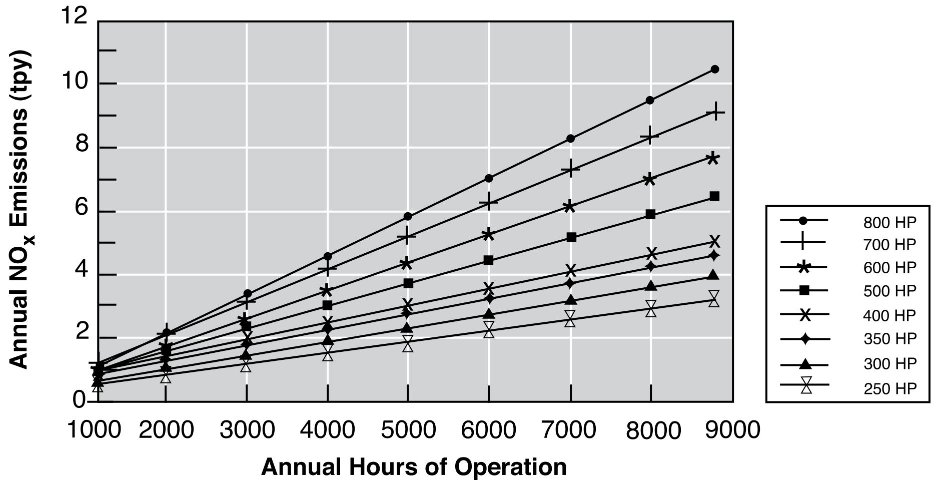
Appendix F

Annual NO_X Emissions for 250-800 Horsepower Boilers NO_X = 30 ppm*



Efficiency = 80%
*ppm corrected to 3% oxygen

Annual NO_X Emissions for 250-800 Horsepower Boilers NO_X = 60 ppm*



Efficiency = 80%
*ppm corrected to 3% oxygen

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