- Section 1.4
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Reference 6

EMISSION FACTOR DOCUMENTATION FOR

AP-42 SECTION 1.4

NATURAL GAS COMBUSTION

Prepared by:

Edward Aul & Associates, Inc.
Chapel Hill, NC 27514

E. H. Pechan & Associates, Inc.
Rancho Cordova, CA 95742

Contract No. 68-DO-0120
EPA Work Assignment Officer: Michael Hamlin

Office of Air Quality Planning and Standards
Office Of Air And Radiation
U.S. Environmental Protection Agency
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1. INTRODUCTION

The document "Compilation of Air Pollutant Emission Factors" (AP-42) has been published by the U.S. Environmental Protection Agency (EPA) since 1972. Supplements to AP-42 have been routinely published to add new emission source categories and to update existing emission factors. The AP-42 is routinely updated by EPA to respond to new emission factor needs of EPA, State, and local air pollution control programs and industry.

An emission factor relates the quantity (mass) of pollutants emitted to a unit of activity of the source. The uses for the emission factors reported in AP-42 include:

1. Estimates of area-wide emissions;
2. Emission estimates for a specific facility; and
3. Evaluation of emissions relative to ambient air quality.

The purpose of this report is to provide background information from over 12 test reports to support revision of emission factors for natural gas combustion.

Including this introduction (Chapter 1), this report contains five chapters. Chapter 2 gives a description of the use of natural gas for combustion in boilers and furnaces. It includes a characterization of the industry, an overview of the different boiler and furnace types, a description of emissions, and a description of the technology used to control emissions resulting from natural gas combustion. Chapter 3 is a review of emissions data collection and analysis procedures. It describes the literature search, the screening of emission data reports, and the quality rating system for both emission data and emission factors. It also describes particle size determination and particle size data analysis methodology. Chapter 4 details pollutant emission factor development. It includes the review of specific data sets, the results of data analysis, and the data base protocol. Chapter 5 presents the AP-42 Section 1.4.

2. INDUSTRY DESCRIPTION

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial and commercial process steam and heat production; for residential and commercial space heating; and for electric power generation.

2.1 CHARACTERISTICS OF THE INDUSTRY[1,2]

As of 1984, it was estimated there were over 1.3 million boilers operating in the U. S. with the capacity of firing either natural gas or distillate oil. The total fuel consumption capacity of this sector amounts to more than 565,000 MW (or 1.9 billion Btu/hour). In this report, MW refers to combustor thermal input, unless otherwise noted.

In addition to industrial and commercial use, there were a reported 42 million residential consumers of natural gas in the U.S., accounting for 58 percent of total residential fuel use. Natural gas-fired boilers and furnaces are located in every region of the nation where natural gas is available through local or national pipelines.

2.2 PROCESS DESCRIPTION[1,2,3]

The primary component of natural gas is methane, although varying amounts of ethane and other gases are also present. Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is combusted.

There are three major types of boilers used for natural gas combustion in the industrial, commercial, and utility sectors: watertube, firetube, and cast iron. The distinguishing design characteristics of each of these boiler types are discussed below, in addition to characteristics of residential furnaces.

2.1.1 Watertube Boilers

Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases. The watertube design is the most common mechanism used for heat transfer in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from the provision of large amounts of process steam to providing hot water or steam for space heating to the generation of high-temperature, high-pressure steam for electricity production. These boilers can range in size from 2.9 to 230+ MW (10 to 800+ million Btu/hr), but most are in the 8.8 to 44 mW (30 to 150 million Btu/hr range). The capacities of field-erected watertube boilers range from 44 to 235 MW (150 to 800 million Btu/hr); packaged boilers predominate below this range. These boilers can burn natural gas as well as other fossil and non-fossil fuels.

2.2.2 Firetube Boilers

In firetube boilers, the hot combustion gases flow through the tubes, and the water being heated circulates outside of the tubes. These boilers are used primarily for heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are firebox boilers and Scotch Marine boilers.

2.2.3 Cast Iron Boilers

In cast iron boilers, just as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications. Boiler sizes can range from 0.001 to 2.9 MW (0.003 to 10 million Btu/hr) heat input. Most cast iron boilers, however, are smaller than 0.1 MW (0.4 million Btu/hr), with few larger than 0.4 MW (1.5 million Btu/hr).

2.2.4 Residential Furnaces

In residential furnaces, natural gas and air are combined in a burner and mixed to promote efficient combustion. Combustion air is supplied by a small fan in forced air furnaces. Hot combustion gases exchange heat with circulating air before being exhausted from a vent or chimney.

A variety of burner types may be used in residential furnaces, including single port, multiport, inshot, ribbon, and slotted. Heat exchangers are typically of the sectional or drum types. Materials of construction for burners and heat exchangers include cast iron, stamped steel, and tube steel.

2.2.5 Fuel Characteristics[5]

As discussed above, natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts. Inerts are non-combustible species and typically include nitrogen, carbon dioxide (CO_2), and helium. The average gross, or higher, heating value of natural gas is approximately 8,900 kcal/standard cubic meter (1,000 Btu/standard cubic foot), usually varying between 8,000 and 9,800 kcal/scm (900 and 1,100 Btu/scf). A typical compositional analysis for Texas-origin natural gas is shown in Table 2-1.

2.2.6 Combustor Categories

For the purposes of developing AP-42 emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces in these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. As shown in Table 2-2, the primary factor used to demarcate the individual combustor categories is heat input.

2.3 EMISSIONS[1,3]

The principal emissions from natural gas-fired boilers and furnaces are nitrogen oxides (NO_x), carbon monoxide (CO), CO_2, and trace amounts of sulfur dioxide (SO_2) and organic compounds. The factors affecting the formation and emission of these species are discussed below.

2.3.1 Combustion Theory

NO_x formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air, resulting in the formation of thermal NO_x, or to the conversion of chemically-bound nitrogen in the fuel, resulting in fuel NO_x. Due to its characteristically low fuel nitrogen content, nearly all NO_x emissions from natural gas combustion are thermal NO_x.

Experimental measurements of thermal NO_x formation have shown that NO_x concentration is exponentially dependent on temperature and also proportional to the nitrogen concentration, the residence time, and the square root of the oxygen concentration of the flame. Thus the formation of thermal NO_x is affected by four furnace-zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature. The emission trends due to changes in these factors are fairly consistent for all types of boilers and furnaces.

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. In some cases, the addition of NO_x control systems such as low NO_x burners and flue gas recirculation (FGR) will reduce combustion efficiency, resulting in higher CO (and trace organics) emissions relative to uncontrolled boilers.

Nearly all the carbon in natural gas is converted to CO_2 during combustion. Although the formation of CO acts to reduce CO_2 emissions, the relatively large quantities of CO_2 produced tend to mask CO formation effects; CO formation rates do not materially affect CO_2 emission factors.

The rate of trace organics emissions from boilers and furnaces also depends on combustion efficiency. Organic emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of organic species in the natural gas fuel (e.g., ethylene and benzene) may also contribute to organic specie emissions if they are not completely combusted in the boiler.

Because natural gas is a gaseous fuel, filterable particulate matter emissions are typically low. However, to the extent that trace organics are formed during natural combustion and condense in the back half of an EPA particulate sampling train, condensible emissions may be higher than filterable emissions.

SO_2 emissions from natural gas-fired boilers are low because natural gas typically contains less than 0.1 percent sulfur. Sulfur-containing mercaptan, however, is added to natural gas for detection purposes, leading to small amounts of SO_2 emissions.

2.3.2 Boiler Operating Procedures

As discussed above, peak flame temperatures and excess air are the major influences on thermal NO_x formation. Since air preheaters increase peak flame temperatures, use of this device may increase NO_x emissions up to twofold for watertube boilers. A second factor which influences combustion temperature is boiler operating load. At higher loads, the rate at which heat is released within a boiler or furnace is increased, resulting in higher combustion intensity and hence higher flame temperatures. Reduction in NO_x emissions occurs with load reduction in natural gas-fired boilers, with the most significant effect being on boilers with air preheat.

Excess air variations can also influence NO_x emissions from natural gas-fired boilers. Typical natural gas-fired boilers operate at 15 percent excess air or 3 percent excess oxygen in the flue gas. Reducing excess oxygen from higher levels to the 3 percent level can reduce NO_x emissions due to the reduction in available atmospheric nitrogen. Reductions in excess oxygen below this level, however, can lead to boiler operating problems and may result in an increase in NO_x emissions due to higher temperatures (i.e., less dilution air) and to higher CO and total organic compound (TOC) emissions due to less efficient mixing of fuel and air.

2.4 CONTROL TECHNOLOGIES[3,6]

The primary emissions of concern from natural gas-fired boilers are NO_x. Currently, there are two NO_x control techniques being applied to natural gas-fired boilers in significant numbers which result in a characteristic change in NO_x emission levels: low NO_x burners and FGR. These techniques may be applied either separately or in combination to both new and existing boilers. Although the use of low excess air (LEA) has also been viewed as a NO_x control technique for boilers, evaluation of emissions data for LEA-controlled boilers indicates there is not a significant difference between uncontrolled and LEA-controlled boiler emission factors. Therefore, LEA-controlled boilers have not been considered as a separate category for purposes of emission factor development. Other NO_x control techniques, such as Burners Out of Service (BOOS), overfire air, biased firing, and reduced air preheat (RAP), have been applied to natural gas-fired boilers, but not in sufficient numbers with which to develop separate emission factors.

2.4.1 Low NO_x Burners

Low NO_x burners reduce NO_x by carrying out the combustion process in stages. The burner staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The staging of the combustion air also promotes a deprivation of oxygen and less complete mixing of fuel and air in the combustion zone where fuel nitrogen evolves, thereby reducing fuel NO_x formation. The degree of staging is a key operating parameter which influences NO_x emission rates for these systems.

There are basically three types of low NO_x burners being applied on a widespread basis to natural gas-fired boilers: staged air burners, staged fuel burners, and radiant fiber burners. In the staged air burner, combustion air is introduced at two or three locations in the burner area, resulting in primary, secondary, and tertiary air. In a staged fuel burner, natural gas is split into two streams; the two streams are combusted separately in series, forming almost two separate flames. The radiant fiber burner developed for application to cast iron and firetube boilers uses a radiant ceramic surface as the heat source rather than a conventional suspended flame. The burner surface glows flamelessly at about 980 °C (1,800 °F); thermal NO_x is reduced as a result of the lower combustion temperature.

2.4.2 Flue Gas Recirculation

In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with the combustion air prior to being fed to the burner.

The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas is made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of thermal NO_x formed. To a lesser extent, FGR also reduces thermal NO_x formation by lowering the oxygen concentration in the primary flame zone. Flue gas recirculation is effective in reducing NO_x emissions in natural gas-fired boilers since nearly all the NO_x generated during combustion is thermal NO_x. The rate of flue gas recirculation is a key operating parameter which influences NO_x emission rates for these systems.

Major equipment items for an FGR system are the FGR fan, fan motor, and added ducting from the stack to the windbox. In addition, some manufacturers provide a shut-off damper, a flowmeter, and controlled flow damper.

2.4.3 Add-On Controls

In those areas of the U.S. where NO_x emissions must be reduced to their lowest levels, the application of selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) to natural gas-fired boilers is contemplated. Both systems are post-combustion NO_x reduction techniques in which ammonia (or urea) is injected into the flue gas to selectively reduce NO_x to nitrogen and water. In the SCR process, a catalyst is used to allow the reaction to take place at a lower temperature. The ammonia is injected and mixed with flue gas before the stream comes into contact with the catalyst. The SCR process is designed to treat flue gases in the 300 to 430 °C (580 to 800 °F) temperature range.

In the SNCR process, ammonia (or urea) is injected into the upper regions of the boiler so that the NO_x-reduction reactions take place without a catalyst at temperatures of 870 to 1,100 °C (1,600 to 2,000 °F).

TABLE 2-1. TYPICAL NATURAL GAS COMPOSITION[5]

Parameter[a]	Gas constituents, volume percent
Methane (CH_4)	96.00
Nitrogen (N_2)	3.20
Carbon dioxide (CO_2)	0.80
Higher Heating Value	8,600 kcal/standard m^3 (967 Btu/standard ft^3)

[a]For natural gas originating in Texas.

TABLE 2-2. COMBUSTOR CATEGORIES FOR EMISSION FACTORS

Combustor category	Heat input capacity, KW (million Btu/hr)	Boiler/furnace design types
Utility/large industrial boilers	>29.3 (100)	Watertube
Small industrial boilers	2.9-29.3 (10-100)	Watertube and firetube
Commercial boilers	0.09-2.9 (0.3-10)	Firetube and cast iron
Residential furnaces	<0.09 (0.3)	Various

REFERENCES FOR CHAPTER 2

1. Background Information Document For Industrial Boilers, EPA-450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

2. "Particulate and Gaseous Emissions From Natural Gas Furnaces and Water Heaters", Jean L. Muhlbaier, Journal of the Air Pollution Control Association, December 1981.

3. Background Information Document For Small Steam Generating Units, EPA-450/3-87-000, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1987.

4. Evaluation of the Pollutant Emissions From Gas-Fired Forced Air Furnaces: Research Report No. 1503, American Gas Association Laboratories, Cleveland, OH, May 1975.

5. Chemical Engineers' Handbook, Fourth Edition, John H. Perry, Editor, McGraw-Hill Book Company, New York, NY, 1963.

6. "A Low-NO_x Burner For Gas-Fired Firetube Boilers", John P. Kesselring and Wayne V. Krill, Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 2, EPRI CS-4360, Electric Power Research Institute, Palo Alto, CA, January 1986.

3. GENERAL DATA REVIEW AND ANALYSIS PROCEDURES

3.1 LITERATURE SEARCH AND SCREENING

The first step of this investigation involved a search of available literature relating to criteria and noncriteria pollutant emissions associated with natural gas combustion. This search included the following sources:

- AP-42 background files;
- Files and dockets maintained by the Emission Standards Division (ESD) of the Office of Air Quality, Planning, and Standards (OAQPS) for relevant New Source Performance Standards (NSPSs) and National Emission Standards on Hazardous Air Pollutants (NESHAPs);
- "Locating and Estimating" reports available through EPA's Clearinghouse for Inventories and Emission Factors (CHIEF) bulletin board system;
- Particulate matter of less than ten microns in diameter (PM-10) "gap filling" documents in the OAQPS library;
- Publications available through EPA's Control Technology Center;
- Reports and project summaries from EPA's Office of Research and Development;
- Control Techniques Guideline documents generated by the ESD of OAQPS;
- Information in the Air Facility System (AFS) of EPA's Aerometric Information Retrieval System (AIRS);
- Handbook of Emission Factors, Parts I and II, Ministry of Health and Environmental Protection, The Netherlands;
- EPA's CHIEF and National Air Toxics Information Clearinghouse (NATICH);

- EPA databases, including SPECIATE, XATEF, and TSAR;
- Various EPA contractor reports; and
- Various files maintained by the Contractor.

To reduce the large amount of literature collected to a final group of references pertinent to this report, the following general criteria were used:

1. Emissions data must be from a primary reference:

a. Source testing must be from a referenced study that does not reiterate information from previous studies.

b. The document must constitute the original source of test data. For example, a technical paper was not included if the original study was contained in the previous document. If the exact source of the data could not be determined, the document was eliminated.

2. The referenced study must contain test results based on more than one test run.

3. The report must contain sufficient data to evaluate the testing procedures and source operating conditions (e.g., one-page reports were generally rejected).

A final set of reference materials was compiled after a thorough review of the pertinent reports, documents, and information according to these criteria.

3.2 EMISSION DATA QUALITY RATING SYSTEM[1]

As part of the Contractor's analysis of the emission data, the quantity and quality of the information contained in the final set of reference documents were evaluated. The following data were always excluded from consideration.

1. Test series averages reported in units that cannot be converted to the selected reporting units;

2. Test series representing incompatible test methods (i.e., comparison of EPA method 5 front-half with EPA method 5 front- and back-half);

3. Test series of controlled emissions for which the control device is not specified;

4. Test series in which the source process is not clearly identified and described; and

5. Test series in which it is not clear whether the emissions were measured before or after the control device.

Data sets that were not excluded were assigned a quality rating. The rating system used that specified by the OAQPS for the preparation of AP-42 sections. The data were rated as follows:

A--Multiple tests performed on the same source using sound methodology and reported in enough detail for adequate validation. These tests do not necessarily conform to the methodology specified in either the inhalable particulate (IP) protocol documents or the EPA reference test methods, although these documents and methods were certainly used as a guide for the methodology actually used.

B--Tests that were performed by a generally sound methodology but lack enough detail for adequate validation.

C--Tests that were based on an untested or new methodology or that lacked a significant amount of background data.

D--Tests that were based on a generally unacceptable method but may provide an order-of-magnitude value for the source.

The following criteria were used to evaluate source test reports for sound methodology and adaquate detail:

1. Source operation. The manner in which the source was operated was well documented in the report. The source was operating within typical parameters during the test.

2. Sampling procedures. The sampling procedures conformed to a generally acceptable methodology. If actual procedures deviated from accepted methods, the deviations are well documented. When deviations occurred, an evaluation was made of the extent such alternative procedures could influence the test results.

3. Sampling and process data. Adequate sampling and process data are documented in the report. Many variations can occur unnoticed and without warning during testing. Such variations can include wide deviations in sampling results. If a large spread between test results cannot be explained by information contained in the test report, the data are suspect and were given a lower rating.

4. Analysis and calculations. The test reports contain original raw data sheets. The nomenclature and equations used were compared to those (if any) specified by EPA to establish equivalency. The depth of review of the calculations was dictated by the reviewer's confidence in the ability and conscientiousness of the tester, which in turn was based on factors such as consistency of results and completeness of other areas of the test report.

3.3 PARTICLE SIZE DETERMINATION

There is no one method which is universally accepted for the determination of particle size. A number of different techniques can be used which measure the size of particles according to their basic physical properties. Since there is no "standard" method for particle size analysis, a certain degree of subjective evaluation was used to determine if a test series was performed using a sound methodology for particle sizing.

For pollution studies, the most common types of particle sizing instruments are cyclones and cascade impactors. Traditionally, cyclones have been used as a preseparator ahead of a cascade impactor to remove the larger particles. These cyclones are of the standard reverse-flow design whereby the flue gas enters the cyclone through a tangential inlet and forms a vortex flow pattern. Particles move outward toward the cyclone wall with a velocity that is determined by the geometry and flow rate in the cyclone and by their size. Large particles reach the wall and are collected. A series of cyclones with progressively decreasing cut-points can be used to obtain particle size distributions.

Cascade impactors used for the determination of particle size in process streams consist of a series of plates or stages containing either small holes or slits with the size of the openings decreasing from one plate to the next. In each stage of an impactor, the gas stream passes through the orifice or slit to form a jet that is directed toward an impaction plate. For each stage, there is a characteristic particle diameter that has a 50 percent probability of impaction. This characteristic diameter is called the cut-point (D_{50}) of the stage. Typically, commercial instruments have six to eight impaction stages with a backup filter to collect those particles which are either too small to be collected by the last stage or which are re-entrained off the various impaction surfaces by the moving gas stream.

3.4 EMISSION FACTOR QUALITY RATING SYSTEM

The quality of the emission factors developed from analysis of the test data was rated utilizing the following criteria:

A--Excellent: Developed only from A-rated test data taken from many randomly chosen facilities in the industry population. The source category is specific enough so that variability within the source category population may be minimized.

B--Above average: Developed only from A-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industries. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.

C--Average: Developed only from A- and B-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.

D--Below average: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Any limitations on the use of the emission factor are footnoted in the emission factor table.

E--Poor: The emission factor was developed from C- and D-rated test data, and there is reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Any limitations on the use of these factors are always clearly noted.

The use of these criteria is somewhat subjective and depends to an extent on the individual reviewer. Details of the rating of each candidate emission factor are provided in Chapter 4 of this report.

REFERENCES FOR CHAPTER 3

1. Technical Procedures for Developing AP-42 Emission Factors and Preparing AP-42 Sections (Draft), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, March 1992.

4. POLLUTANT EMISSION FACTOR DEVELOPMENT

This chapter describes the test data and methodology used to develop pollutant emission factors for natural gas combustion in boilers and furnaces.

4.1 REVIEW OF SPECIFIC DATA SETS

A total of 12 references were documented and reviewed during the literature search. These references are listed at the end of this chapter. The source data for this revision included emission data from the September 1991 version of AP-42 Section 1.4.

The following efforts were made to ensure that the selection and rating of the reference documents did not introduce bias in the data. The majority of references used (i.e., seven) were either compliance test reports or summaries of compliance test report results. Given the impetus for compliance testing, these reports would be expected to characterize facilities with various levels of maintenance, operation, and control. The remaining references used in this report were classified as research or special study tests. In some cases, it could be reasoned that such studies would involve testing of facilities with above average maintenance, operation, and control and would, therefore, not be representative of the industry. Rather than downgrade the ratings for these references, each reference was considered on its own merit.

No emission test reports reviewed were excluded from consideration based on the criteria outlined in Chapter 3. The following is a discussion of the data contained in each of the primary references used to develop candidate emission factors. Emission factors were developed in terms of weight of pollutant per cubic foot or per cubic meter of natural gas combusted, consistent with previous versions of AP-42 Section 1.4. It should be noted that the terms "controlled" and "uncontrolled" in this discussion refer to the condition of the boiler or furnace at the time measurements

were made. Typically, NO_x controls were the only control systems applied to natural gas combustors. If a NO_x control system was employed on a boiler or furnace during a test, measurements of NO_x and other pollutants are classified according to the NO_x control system in operation; if no NO_x
control system was in operation, the combustor is considered to be uncontrolled.

A summary of the filterable and condensible particulate matter (PM) emissions data are contained in Table 4-1. Tables 4-2 and 4-3 present summaries of emissions data for NO_x, CO, CO_2, and TOC. Table 4-4 provides an overview of the data presented in Tables 4-1 through 4-3 that were used to develop corresponding emission factors.

4.1.1 References 1 Through 3

References 1 thorough 3 were NO_x compliance tests performed on three different natural gas-fired boilers operating with FGR systems for NO_x control. Testing results were presented in these references for NO_x, CO, and CO_2. These data were obtained with a chemiluminescent continuous emission monitor (CEM) for NO_x and nondispersive infrared (NDIR) monitors for CO and CO_2. Although the tests were conducted using a generally sound methodology, raw data sheets and other detailed information were lacking with which to perform adequate validation. For these reasons, a rating of B was assigned to the data in each reference.

4.1.2 Reference 4

In this reference, a burner manufacturer presented controlled and uncontrolled data for five boilers operating with low NO_x burners. Results for NO_x, CO, and TOC were obtained using unspecified CEMs. Raw data sheets and other detailed information were lacking with which to perform adequate validation. For these reasons, a rating of B was assigned to the reported test data.

4.1.3 Reference 5

This reference contained the results of emission tests conducted on three residential furnaces, all operating without any explicit pollutant control devices. Data were collected for both filterable and condensible particulate matter (PM) using EPA Method 5. Additional data for NO_x, CO, and TOC were collected with unspecified CEMs. A rating of B was assigned to the emission test data in this reference due to the lack of raw data sheets and other detailed information with which to perform adequate validation.

4.1.4 References 6 and 7

References 6 and 7 were extended field tests of a commercial boiler using LEA for NO_x control and an industrial boiler fitted with low NO_x burners. The objective of each test was to determine whether combustion modification techniques which demonstrated reduction of air pollutant emissions during short-term tests were feasible for longer periods. Test results were presented for NO_x, CO, and CO_2 on a daily average basis. The daily averages were summed and divided by the number of test days to calculate the overall test averages. Emissions data were collected with a chemiluminescent NO_x analyzer and NDIR CO and CO_2 analyzers. A rating of A was assigned to the data from each reference.

4.1.5 Reference 8

This reference reported the results of emissions testing on 38 natural gas-fired forced air furnaces spanning a range of furnace, burner, and heat exchanger types. No specific pollutant control technologies were in operation during testing. The pollutants analyzed were NO_x, CO, CO_2, and aliphatic aldehydes (reported as formaldehyde). Average emission rates were presented for the furnaces operating under both blue flame conditions and yellow flame conditions. Since both conditions were reported to be encountered in field operating units, the two data sets were combined to yield overall average emission rates for all furnaces tested. A chemiluminescent monitor was used to collect NO_x data; NDIR monitors were used to collect CO and CO_2 data. The MBTH (3-methyl-2-benzothiazolone hydrazone) method was used to determine the total water-soluble aliphatic aldehydes in the flue gas samples. Due to a lack of raw data sheets and other detailed information with which to provide adequate validation, the test data in this reference were assigned a B rating.

4.1.6 Reference 9

The results of field emission tests on six boilers (three small industrial and three commercial) were reported in Reference 9, all operating in an uncontrolled manner. Test results were reported for NO_x, CO, CO_2, TOC, filterable PM, and condensible PM. CEMs were used to collect NO_x (electrochemical), CO (NDIR), CO_2 (NDIR), and TOC (flame ionization) data. The EPA particulate sampling train was used to collect filterable and condensible PM data. These data were assigned an A rating.

4.1.7 Reference 10

The test data in this reference, attached to a private communication, apply to a commercial boiler fitted with a low NO_x burner. Results were reported for NO_x, CO, and CO_2 but the methods of analysis are not specified. Due to the low level of supporting data attending these data, they were considered to be useful for order-of-magnitude estimates only and hence were assigned a rating of D.

4.1.8 Reference 11

Reference 11 was a report prepared by an EPA contractor which summarized emission test data for low NO_x burners applied to small and large industrial boilers and commercial boilers. Only NO_x emission data were reported, as measured by CEMs. Because of the lack of raw data sheets and other detailed information which would allow for adequate verification, the test data were assigned a B rating.

4.1.9 Reference 12

Reference 12 was also an EPA contractor-prepared report which summarized test data for small industrial and commercial boilers. Data were reported for uncontrolled boilers as well as boilers equipped with low NO_x burners and FGR systems. Continuous emission monitoring data were summarized for NO_x and CO. The boilers tested were either new boilers or had recently been retrofitted with NO_x control systems. The emissions test data were used to evaluate the technical basis for a NSPS for small industrial and commercial boilers. Although sufficient information was presented to evaluate boiler and control system operation, the lack of raw data sheets and other verification data resulted in a B rating for these test data.

4.2 RESULTS OF DATA ANALYSIS

This section discusses the development of emission factors for tested pollutants based on the data contained in the reference documents described above. In all cases, emission factors were developed using manual and computer spreadsheet manipulation of emission data and factors expressed in units other than the mass of pollutant per million cubic meters (or feet) of natural gas combusted.

In some cases, new test data were not utilized if, based on the overall quality, it was determined that the data did not provide significant information that would improve the rating of an existing emission factor, but would diminish its credibility and usefulness. In addition, no new data were located which could be used to revise the uncontrolled emission factors for utility/large industrial boilers or small industrial boilers. Thus, the uncontrolled priority pollutant emission factors for these boilers (which have an overall A - Excellent rating) will continue to be used in this revision of AP-42 Section 1.4.

A summary of developed emission factors for tested pollutants is shown in Table 4-4. All combustor size values discussed in this section refer to heat input capacity. In addition, emission test data were obtained for packaged boilers only; no new data were obtained for field-erected natural gas-fired boilers.

4.2.1 Filterable Particulate Matter

Uncontrolled filterable PM emission factors were determined from the data contained in References 5 and 9. Particulate matter controls are not normally applied to natural gas-fired combustors due to inherently low PM emissions; hence, no controlled PM emission factors were developed. Data for small industrial boilers were obtained from a firetube and a watertube boiler with heat input capacities of 2.9 and 5.9 MW (10 and 20 million Btu/hr). Two commercial firetube and two commercial cast iron commercial boilers were tested which ranged in size from 0.4 to 0.9 MW (1.3 to 3.2 million Btu/hr). Three residential furnaces were tested ranging from 30 to 50 KW (110,000 to 165,000 Btu/hr). These furnaces were equipped with ribbon jet and slotted jet burners.

4.2.2 Condensible Particulate Matter

As with filterable PM, only uncontrolled emission factors were developed for condensible PM. References 5 and 9 contained useful data. Two small industrial boilers were tested (one firetube and one watertube boiler) ranging in size from 2.9 to 5.9 MW (10 to 20 million Btu/hr). Two commercial firetube and two commercial cast iron boilers were tested which ranged from 0.4 to 0.9 MW (1.3 to 3.2 million Btu/hr). Data for one slotted residential jet furnace, rated at 37 KW (125,000 Btu/hr) were available.

4.2.3 Nitrogen Oxides

Both controlled and uncontrolled emission factors were developed from the test data in References 1, 2, 3, 4, 5, 8, 9, 11, and 12. For utility/large industrial boilers, data were available from two boilers fitted with low NO_x burners and one boiler using FGR. All these boilers were watertube units and ranged in size from 29.3 to 47.5 MW (100 to 162 million Btu/hr). Fourteen small industrial boilers (all watertube units) equipped with either low NO_x burners or FGR systems were tested; these boilers ranged in size from 3.8 to 29.3 MW (13 to 100 million Btu/hr).

Uncontrolled NO_x data with A ratings were available for two firetube and two cast iron commercial boilers ranging from 0.4 to 0.9 KW (1.3 to 3.2 million Btu/hr); lower rated data from three other commercial boilers were not utilized. Controlled test data were available for four firetube commercial boilers ranging from 0.2 to 2.1 MW (0.8 to 7 million Btu/hr) and equipped with either low NO_x burners or FGR systems.

Uncontrolled test data from 41 residential furnaces ranging in size from 22 to 52 KW (75,000 to 179,000 Btu/hr) were utilized. These furnaces included a wide array of burner and heat exchange types.

4.2.4 Carbon Monoxide

Carbon monoxide emission factors were developed for both uncontrolled and NO_x-controlled boilers using the test data in References 2, 3, 4, 5, 8, 9, and 12. Data from 10 NO_x-controlled boilers were available from small industrial boilers. These units included both firetube and watertube boilers ranging in size from 5.0 to 29.3 MW (17 to 100 million Btu/hr). For commercial boilers, data were available for six uncontrolled boilers [0.2 to 0.9 MW (0.8 to 3.2 million Btu/hr)] and four NO_x-controlled boilers [0.2 to 1.0 MW (0.8 to 3.4 million Btu/hr)]; these boilers included both firetube and cast iron units. Uncontrolled data were available from 41 residential furnaces ranging from 20 to 55 KW (75,000 to 179,000 Btu/hr) and equipped with a wide variety of burners and heat exchangers.

4.2.5 Carbon Dioxide

Uncontrolled CO_2 emission factors were developed for small industrial boilers, commercial boilers, and residential furnaces; a CO_2 emission factor for NO_x-controlled combustors was developed for small industrial boilers. Data in References 5, 7, 8, 9, and 10 were useful. For small industrial boilers, uncontrolled emissions data were available for one firetube boiler [2.9 MW (10 million Btu/hr)] and one watertube boiler [5.9 MW (20 million Btu/hr)]. Controlled emissions data were available for a watertube boiler fitted with low NO_x burners rated at 25 MW (85 million Btu/hr) and a firetube boiler operating with FGR rated at 3.9 MW (13 million Btu/hr). Uncontrolled CO_2 data for commercial boilers were obtained from two firetube and two cast iron units which ranged in size from 0.4 to 0.9 MW (1.3 to 3.2 million Btu/hr). For residential furnaces, uncontrolled CO_2 data were available from 41 units ranging from 20 to 55 KW (75,000 to 179,000 Btu/hr) in size and equipped with a wide variety of burners and heat exchangers.

4.2.6 Total Organic Compounds

Controlled and uncontrolled TOC emission factors were developed based on the test data in References 4, 5, and 9. Uncontrolled TOC data were available from four firetube commercial boilers rated between 0.4 and 0.9 MW (1.3 and 3.2 million Btu/hr). Total organic compounds data were also available for one firetube commercial boiler fitted with a low NO_x burner and rated at 0.2 MW (0.8 million Btu/hr). Uncontrolled TOC data were available from three residential furnaces ranging in size from 30 to 50 KW (110,000 to 165,000 Btu/hr). However, only the overall average TOC emission rates were reported for the three furnaces; the results of individual furnace tests were not reported. The furnaces operated with ribbon jet and slotted jet burners.

4.3 PROTOCOL FOR DATA BASE

4.3.1 Engineering Methodology

The 12 references discussed in Section 4.1 were thoroughly reviewed to establish a data base for the pollutants discussed above. Data rating forms (see Appendix A) were created to facilitate the evaluation of exclusion criteria, methodology/detail criteria, and data rating criteria. These forms were completed for each reference to document the rationale for either excluding the reference from emission factor development consideration or for including the reference and assigning ratings to relevant source test data.

The emissions data from source test reports were averaged as the arithmetic mean of different sampling runs prior to inclusion in the data base. Test programs at most facilities consisted of three sampling runs conducted during distinct time periods under normal operating conditions for the systems tested.

Due to the variety of formats used to report units of measure at different natural gas-fired combustors, the emission data required some processing to standardize the units of measure prior to calculation of emission factors. Average emission factors were then calculated in terms of kg/million m^3 or lb/million ft^3 of natural gas combusted for all pollutants based on the arithmetic average of collected data. The list of conversion factors used in the test data processing are included in Table 4-5.

In many cases it was necessary to convert data expressed in terms of lb pollutant/million Btu or ppmv to kg pollutant /million m^3 (or lb pollutant/million ft^3) of natural gas fired. Based on the information contained in References 1 through 9, this conversion was made using an average natural gas heating value of 1,000 Btu/ft^3. In addition, an F-Factor of 2.43 10^7 dscm/J (8,710 dscf/million Btu) at 0 percent oxygen (O_2) was utilized.[13] This factor was adjusted to other O_2 flue gas concentrations using the equation

$$F = 8{,}710 \text{ dscf}/10^6 \text{ Btu } [20.9/(20.9\text{-}\%O_{2d})]$$

where $\%O_{2d}$ is the flue gas O_2 content measured on a dry basis.

Determinations of emission factors were made only when natural gas combustion rates were documented or derivable from plant records.

Quality control and quality assurance procedures were used to assure that the data base accurately reflected the reported test data. Each data rating form was checked by a second reviewer to assure accurate documentation of reference exclusion or emission data rating criteria. In addition, manual and spreadsheet calculations were spot checked by a second reviewer to assure accurate documentation of reported emission and process data prior to calculation of overall average emission factors. After emission tables were generated, a final comparison was made between randomly selected test reports, their associated data rating forms, and the produced emission table to assure the quality of the data acquisition and associated calculations.

TABLE 4-1. SUMMARY OF EMISSION FACTORS FOR PM

Source category/ reference/rating	Filterable PM, $kg/10^6 m^3$ ($lb/10^6 ft^3$)	Condensible PM, $kg/10^6 m^3$ ($lb/10^6 ft^3$)
Small industrial boilers		
Uncontrolled		
9,a	110 (6.9)	160 (10)
9,a	88 (5.5)	88 (5.5)
Commercial boilers		
Uncontrolled		
9,a	66 (4.1)	140 (9.0)
9,a	45 (2.8)	120 (7.6)
9,a	77 (4.8)	66 (4.1)
9,a	99 (6.2)	140 (9.0)
Residential furnaces		
Uncontrolled		
5,b	2.9 (0.18)	180 (11)
5,b	2.2 (0.14)	
5,b	3.2 (0.20)	

TABLE 4-2. SUMMARY OF EMISSION FACTORS FOR NO_x

Source category/reference/rating	Uncontrolled, $kg/10^6 m^3$ ($lb/10^6 ft^3$)	Controlled, $kg/10^6 m^3$ ($lb/10^6 ft^3$)	Efficiency, percent
Utility/large industrial boilers			
Low NO_x burner			
11,b		1100 (68)	
11,b		1400 (89)	
Flue gas recirculation			
12,b		850 (53)	
Small industrial boilers			
Low NO_x burners			
12,b		1400 (90)	
12,b		1100 (70)	
12,b		1400 (90)	
Flue gas recirculation			
2,b		510 (32)	
3,b		540 (34)	
10,d		380 (24)	
12,b	1600 (102)[a]	580 (36)	65
12,b	1200 (78)[a]	430 (27)	65
12,b	1300 (79)[a]	640 (40)	49
12,b	1300 (79)[a]	480 (30)	62
12,b	900 (56)[a]	350 (22)	61
12,b	1100 (69)[a]	260 (16)	77
12,b	1800 (110)[a]	510 (32)	71
12,b	1800 (110)[a]	460 (29)	74
12,b	1800 (110)[a]	430 (27)	75
Commercial boilers			
Uncontrolled			
9,a	1800 (110)		
9,a	2000 (126)		
9,a	1100 (68)		
9,a	1400 (86)		

TABLE 4-2. SUMMARY OF EMISSION FACTORS FOR NO_x (Continued)

Source category/reference/rating	Uncontrolled, $kg/10^6 m^3$ ($lb/10^6 ft^3$)	Controlled, $kg/10^6 m^3$ ($lb/10^6 ft^3$)	Efficiency, percent
Low NO_x burners			
4,b	980 (61)	180 (11)	82
4,b		340 (21)	
4,b	1400 (86)	300 (19)	78
Flue gas recirculation			
1,b	1500 (96)[a]	580 (36)	63
Residential furnaces			
Uncontrolled			
5,b	2100 (130)[b]		
8,b	1400 (90)[c]		

[a]Without flue gas recirculation (but may include low NO_x burners).
[b]Average of 3 furnaces tested.
[c]Average of 38 furnaces tested.

TABLE 4-3. SUMMARY OF EMISSION FACTORS FOR CO, CO_2, and TOC

Source category/reference/rating	CO, $kg/10^6m^3$ $(lb/10^6ft^3)$	CO_2, $kg/10^6m^3$ $(lb/10^6ft^3)$	TOC, $kg/10^6m^3$ $(lb/10^6ft^3)$
Small industrial boilers			
Uncontrolled			
9,a		1.9 E6 (120,000)	
9,a		1.8 E6 (110,000)	
Low NO_x burner			
12,b	980 (61)		
7,a		1.6 E6 (100,000)	
Flue gas recirculation			
3,b	1300 (79)		
2,b	820 (51)		
10,d	140 (8.9)	1.9 E6 (120,000)	
12,b	670 (42)		
12,b	1000 (63)		
12,b	240 (15)		
12,b	660 (41)		
12,b	190 (12)		
12,b	240 (15)		
12,b	190 (12)		
Commercial boilers			
Uncontrolled			
4,b	110 (7.0)		
4,b	160 (10)		
9,a	720 (45)	1.9 E6 (120,000)	290 (18)
9,a	11 (0.69)	1.9 E6 (120,000)	2.2 (0.14)
9,a	110 (6.9)	1.9 E6 (120,000)	22 (1.4)
9,a	860 (54)	1.9 E6 (120,000)	59 (3.7)
Low NO_x burners			
4,b	96 (6.0)		110 (7)
4,b	96 (6.0)		
4,b	370 (23)		
4,b	370 (23)		

TABLE 4-3. SUMMARY OF EMISSION FACTORS FOR CO, CO_2, AND TOC (Continued)

Source category/reference/rating	CO, $kg/10^6 m^3$ ($lb/10^6 ft^3$)	CO_2, $kg/10^6 m^3$ ($lb/10^6 ft^3$)	TOC, $kg/10^6 m^3$ ($lb/10^6 ft^3$)
Residential furnaces			
Uncontrolled			
5,b	1300 (81)	2.0 E6 (130,000)	180 (11)
8,b	600 (37)	2.0 E6 (130,000)	

TABLE 4-4. SUMMARY OF NATURAL GAS COMBUSTION EMISSION DATA

Pollutant/source	No. of data points	Data ratings	Emission factor range, $kg/10^6 m^3$	Average emission factor, $kg/10^6 m^3$	Efficiency[a]	Emission factor rating	Reference Number
Filterable particulate matter							
Small industrial boilers							
Uncontrolled	2	a	88-110	99		D	9
Commercial boilers							
Uncontrolled	4	a	45-99	72		B	9
Residential furnaces							
Uncontrolled	3	b	2.2-3.2	2.8		C	5
Condensible particulate matter							
Small industrial boilers							
Uncontrolled	2	a	88-160	120		D	9
Commercial boilers							
Uncontrolled	4	a	66-140	120		C	9
Residential furnaces							
Uncontrolled	1	b		180		D	5
Nitrogen oxides							
Utility/large industrial boilers							
Controlled							
Low NO_x burners	2	b	1100-1400	1300		D	11
Flue gas recirculation	1	b		850		D	12
Small industrial boilers							
Controlled							
Low NO_x burners	3	b	1100-1400	1300		D	12
Flue gas recirculation	11	b	260-640	480	79	C	2,3,12
Commercial boilers							
Uncontrolled	4	a	1100-2000	1600		B	9
Controlled							
Low NO_x burners	3	b	180-340	270	83	C	4

TABLE 4-4. SUMMARY OF NATURAL GAS COMBUSTION EMISSION DATA (Continued)

Pollutant/source	No. of data points	Data ratings	Emission factor range, $kg/10^6 m^3$	Average emission factor, $kg/10^6 m^3$	Efficiency[a]	Emission factor rating	Reference Number
Flue gas recirculation	1	b		580	64	D	1
Residential furnaces							
Uncontrolled	41	b	1400-2100	1500		B	5,8
Carbon monoxide							
Small industrial boilers							
Controlled							
Low NO_x burners	1	b		980		D	12
Flue gas recirculation	9	b		590		C	2,3,12
Commercial boilers							
Uncontrolled	6	a,b	11-860	330		C	4,9
Controlled							
Low NO_x burners	4	b	96-370	425		C	4
Residential furnaces							
Uncontrolled	41	b	600-1300	640		B	5,8
Carbon dioxide							
Small industrial boilers							
Uncontrolled	2	a	1.8 E6-1.9 E6	1.9 E6		D	9
Controlled				1.9 E6		D	7
Low NO_x burners	1	a		1.9 E6		E	10
Flue gas recirculation	1	d		1.9 E6		C	9

TABLE 4-4. SUMMARY OF NATURAL GAS COMBUSTION EMISSION DATA (Continued)

Pollutant/source	No. of data points	Data ratings	Emission factor range, $kg/10^6 m^3$	Average emission factor, $kg/10^6 m^3$	Efficiency[a]	Emission factor rating	Reference Number
Commercial boilers							
Uncontrolled	4	a					
Residential boilers							
Uncontrolled	2	b		2.0 E6		D	5,8
<u>Total organic compounds</u>							
Commercial boilers							
Uncontrolled	4	a	2.2-290	93		C	9
Controlled							
Low NO_x burners	1	b		110		D	4
Residential furnaces							
Uncontrolled	3	b		180		D	5

[a]Relative to uncontrolled emissions.

TABLE 4-5. LIST OF CONVERSION FACTORS

Multiply	By	To obtain
mg/dscm	4.37E-4	gr/dscf
m^2	10.764	ft^2
acm/min	35.31	acfm
m/s	3.281	ft/s
kg/h	2.205	lb/h
Kpa	4.0	in. of H_2O
lpm	0.264	gal/min
kg/Mg	2.0	lb/ton

Temperature conversion equations

F= (9/5)*C+32

C= (5/9)*(F-32)

REFERENCES FOR CHAPTER 4

1. Emissions Test on 200 HP Boiler at Kaiser Hospital in Woodland Hills, Energy Systems Associates, Tustin, CA, June 1986.

2. Results From Performance Tests: California Milk Producers Boiler No. 5, Energy Systems Associates, Tustin, CA, November 1984.

3. Source Test For Measurement of Nitrogen Oxides and Carbon Monoxide Emissions From Boiler Exhaust at GAF Building Materials, Pacific Environmental Services, Inc., Baldwin Park, CA, May 1991.

4. "A Low-NO_x Burner For Gas-Fired Firetube Boilers", John P. Kesselring and Wayne V. Krill, Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 2, EPRI CS-4360, Electric Power Research Institute, Palo Alto, CA, January 1986.

5. "Particulate and Gaseous Emissions From Natural Gas Furnaces and Water Heaters", Jean L. Muhlbaier, Journal of the Air Pollution Control Association, December 1981.

6. Thirty-day Field Tests of Industrial Boilers: Site 6 -Gas-fired Fire-tube Boiler, EPA-600/7-81-095b, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

7. Thirty-day Field Tests of Industrial Boilers: Site 5 -Gas-fired Low-NO_x Burner, EPA-600/7-81-095a, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

8. Evaluation of the Pollutant Emissions From Gas-Fired Forced Air Furnaces: Research Report No. 1503, American Gas Association Laboratories, Cleveland, OH, May 1975.

9. Field Investigation of Emissions From Combustion Equipment for Space Heating, EPA-R2-73-084a, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1973.

10. Private communication from Kim Black (Industrial Combustion) to Ralph Harris, Midwest Research Institute (MRI), Independent Third Party Source Tests, February 7, 1992.

11. NO_x Emission Control Technology Update, EPA Contract No. 68-01-6558, Radian Corporation, Research Triangle Park, NC, January 1984.

12. Background Information Document For Small Steam Generating Units, EPA-450/3-87-000, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1987.

13. 40 Code of Federal Regulations, Chapter 1, July 1991 Edition, Part 60, Appendix A, Method 19.

5. AP-42 SECTION 1.4: NATURAL GAS COMBUSTION

The revision to Section 1.4 of AP-42 is presented in the following pages as it would appear in the document. A marked-up copy of the 1986 version of this section is included in Appendix B.

1.4 NATURAL GAS COMBUSTION

1.4.1 General[1-2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is used (see Natural Gas Processing, Section 9.2). The average gross heating value of natural gas is approximately 8900 kilocalories per standard cubic meter (1000 British thermal units per standard cubic foot), usually varying from 8000 to 9800 kcal/scm (900 to 1100 Btu/scf).

1.4.2 Emissions and Controls[3-5]

Even though natural gas is considered to be a relatively clean-burning fuel, some emissions can result from combustion. For example, improper operating conditions, including poor air/fuel mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide (CO), and organic compound emissions. Moreover, because a sulfur-containing mercaptan is added to natural gas to permit leak detection, small amounts of sulfur oxides will be produced in the combustion process.

Nitrogen oxides (NO_x) are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions depend primarily on the peak temperature within the combustion chamber as well as the furnace-zone oxygen concentration, nitrogen concentration, and time of exposure at peak temperatures. Emission levels vary considerably with the type and size of combustor and with operating conditions (particularly combustion air temperature, load, and excess air level in boilers).

Currently, the two most prevalent NO_x control techniques being applied to natural gas-fired boilers (which result in characteristic changes in emission rates) are low NO_x burners and flue gas recirculation. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses NO_x formation. The three most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners, staged fuel burners, and radiant fiber burners. Nitrogen oxide emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners. Other combustion staging techniques which have been applied to natural gas-fired boilers include low excess air, reduced air preheat, and staged combustion (e.g., burners-out-of-service and overfire air). The degree of staging is a key operating parameter influencing NO_x emission rates for these systems.

In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas in made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of NO_x formed. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of flue gas recirculated is a key operating parameter influencing NO_x emission rates for these systems. Flue gas recirculation is normally used in combination with low NO_x burners. When used in combination, these techniques are capable of reducing uncontrolled NO_x emissions by 60 to 90 percent.

Two post-combustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions by further amounts are selective noncatalytic reduction and selective catalytic reduction. These systems inject ammonia (or urea) into combustion flue gases to reduce inlet NO_x emission rates by 40 to 70 percent.

Although not measured, all particulate matter (PM) from natural gas combustion has been estimated to be less than 1 micrometer in size. Particulate matter is composed of filterable and condensible fractions, based on the EPA sampling method. Filterable and condensible emission rates are of the same order of magnitude for boilers; for residential furnaces, most of the PM is in the form of condensible material.

The rates of CO and trace organic emissions from boilers and furnaces depend on the efficiency of natural gas combustion. These emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. In some cases, the addition of NO_x control systems such as FGR and low NO_x burners reduces combustion efficiency (due to lower combustion temperatures), resulting in higher CO and organic emissions relative to uncontrolled boilers.

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1 through 1.4-3. For the purposes of developing emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. The primary factor used to demarcate the individual combustor categories is heat input.

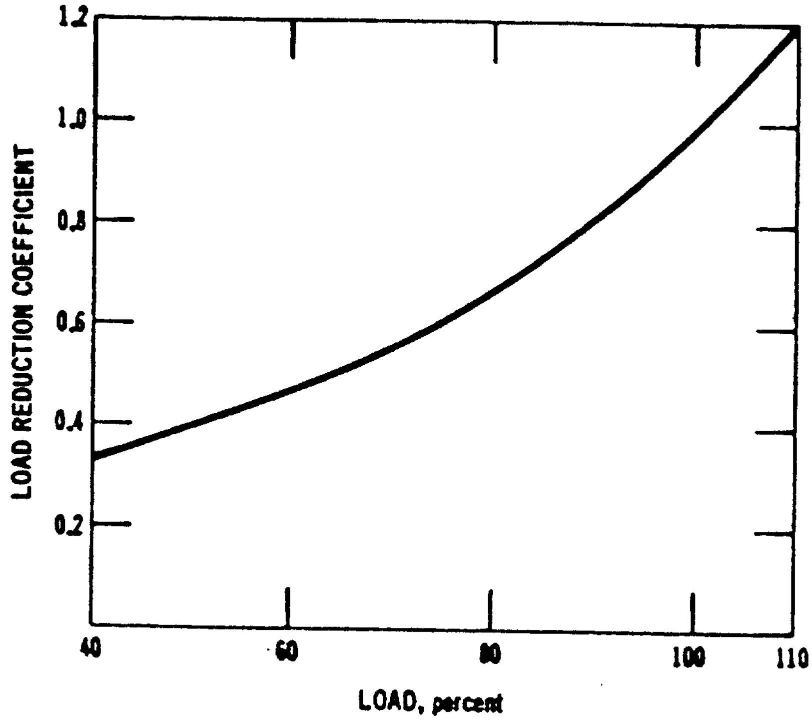

Figure 1.4-1. Load reduction coefficient as a function of boiler load. (Used to determine NO_X reductions at reduced loads in large boilers.)

Table 1.4-1. EMISSION FACTORS FOR PARTICULATE MATTER (PM) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr heat input) [SCC][b]	Filterable PM[c]			Condensible PM[d]		
	kg/10^6 m^3	lb/10^6 ft^3	Rating	kg/10^6 m^3	lb/10^6 ft^3	Rating
Utility/large industrial boilers (>100) [10106001, 10100604]	16-80	1-5	B	ND[e]	ND	
Small industrial boilers (10 - 100) [10200602]	99	6.2	B	120	7.5	D
Commercial boilers (0.3 -<10) [10300603]	72	4.5	C	120	7.5	C
Residential furnaces (<0.3) [no SCC]	2.8	0.18	C	180	11	D

[a]References 9-14. All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters and lbs. of pollutant/10^6 cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.
[b]SCC = Source Classification Code.
[c]Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[d]Condensible PM is that particulate matter collected in the impinger portion of an EPA Method 5 (or equivalent) sampling train. Total PM is the sum of the filterable PM and condensible PM. All PM emissions can be assumed to be less than 10 microns in aerodynamic equivalent diameter (PM-10).
[e]ND = No data.

Table 1.4-2. EMISSION FACTORS FOR SULFUR DIOXIDE (SO_2), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr heat input) [SCC][b]	SO_2[c]			NO_x[d]			CO[e]		
	$kg/10^6 m^3$	$lb/10^6 ft^3$	Rating	$kg/10^6 m^3$	$lb/10^6 ft^3$	Rating	$kg/10^6 m^3$	$lb/10^6 ft^3$	Rating
Utility/Large Industrial Boilers (>100) [10100601, 10100604]									
Uncontrolled	9.6	0.6	A	8800	550[f]	A	640	40	A
Controlled - Low NO_x burners	9.6	0.6	A	1300	81[f]	D	ND[g]	ND	
Controlled - Flue gas recirculation	9.6	0.6	A	850	53[f]	D	ND	ND	
Small Industrial Boilers (10-100) [10200602]									
Uncontrolled	9.6	0.6	A	2240	140	A	560	35	A
Controlled - Low NO_x burners	9.6	0.6	A	1300	81[f]	D	980	61	D
Controlled - Flue gas recirculation	9.6	0.6	A	480	30	C	590	37	C
Commercial Boilers (0.3-<10) [10300603]									
Uncontrolled	9.6	0.6	A	1600	100	B	330	21	C
Controlled - Low NO_x burners	9.6	0.6	A	270	17	C	425	27	C
Controlled - Flue gas recirculation	9.6	0.6	A	580	36	D	ND	ND	
Residential Furnaces (<0.3) [no SCC]									
Uncontrolled	9.6	0.6	A	1500	94	B	640	40	B

[a]Units are kg of pollutant/10^6 cubic meters and lbs. of pollutant/10^6 cubic feet. Based on an average natural gas higher heating value of 8270 $kcal/m^3$ (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.
[b]SCC = Source Classification Code.
[d]Reference 7. Based on average sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).
[e]References 10, 15-19. Expressed as NO_2. For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. Note that NO_x emissions from controlled boilers will be reduced at low load conditions.
[f]References 9-10, 16-18, 20-21.
[g]Emission factors apply to packaged boilers only.
[h]ND = No data.

Table 1.4-3. EMISSION FACTORS FOR CARBON DIOXIDE (CO_2), AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr heat input) [SCC][b]	CO_2[c]			TOC[d]		
	kg/10^6 m^3	lb/10^6 ft^3	Rating	kg/10^6 m^3	lb/10^6 ft^3	Rating
Utility/large industrial boilers (>100) [10100601, 10100604]	ND[e]	ND		28[f]	1.7[f]	C
Small industrial boilers (10-100) [10200602]	1.9E06	1.2E05	D	92[g]	5.8[g]	C
Commercial boilers (0.3-<10) [10300603]	1.9E06	1.2E05	C	92[h]	5.8[h]	C
Residential furnaces [no SCC]	2.0E06	1.3E05	D	180[h]	11[h]	D

[a] All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters and lbs. of pollutant/10^6 cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values bay multiplying the given factor by the ratio of the specified heating value to this average heating value.

[b] SCC = Source Classification Code.

[c] References 10, 22-23.

[d] References 9-10, 18.

[e] ND = No data.

[f] Reference 8: methane comprises 17 percent of organic compounds.

[g] Reference 8: methane comprises 52 percent of organic compounds.

[h] Reference 8: methane comprises 34 percent of organic compounds.

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APPENDIX A
EMISSION SOURCE DATA RATING FORMS

SOURCE CATEGORY________________________

RATING CRITERIA CHECKLIST

Reference____
____

RATING CRITERIA		YES	NO
A	Tests performed by a sound methodology and reported in enough detail for adequate validation?		
B	Tests were performed by a generally sound methodology, but not enough detail for adequate validation?		
C	Were tests based on untested or new methodology that lacks significant amount of background data?		
D	Were tests based on generally unacceptable methods, but may provide order-of-magnitude values for the source?		

COMMENTS

Form filled out by____

Date______________________________

BASED ON ANSWERS AND COMMENTS ABOVE, ASSIGN A RANK TO THIS LITERATURE SOURCE:

RANK ASSIGNED TO EMISSION SOURCE DATA

SOURCE CATEGORY ______
METHODOLOGY/DETAIL CRITERIA CHECKLIST

REFERENCE ______

CRITERIA	YES	NO	COMMENTS
1. Is the manner in which the source was operated well documented in the report?			
Was the source operating within typical parameters during the test?			
2. Did sampling procedures deviate from standard methods?			
If so, were the deviations well documented?			
Were the deviations appropriate?			
Comment on how any alterations in sampling procedure may have influenced the results.			
3. Were there wide variations in the results?			
If yes, can the variations be adequately explained by information in the report?			
If the variations are not well explained, should the data be considered of poor quality?			
4. Do the test reports contain the raw data sheets?			
Are the nomenclature and equations used equivalent to those specified by the EPA?			
Comment on the consistency and completeness of the results.			

Form filled out by ______
Date ______

INDICATE YES OR NO WITH AN "X" IN THE APPROPRIATE BOX. FILL IN COMMENTS.

IF, BASED ON ABOVE ANSWERS, THE SOURCE REPORT PROVIDES ADEQUATE DETAIL AND DEMONSTRATES SOUND METHODOLOGY, PROCEED TO RATING THE DATA IN THE RATING CRITERIA CHECKLIST.

SOURCE CATEGORY:____________________

EXCLUSION CRITERIA CHECKLIST

REFERENCE____

____

CRITERIA	YES	NO
1. Test series averages are reported in units that can be converted to the selected reporting units?		
2. Test series represent compatible test methods?		
3. In tests in which emission control devices were used, the control devices are fully specified?		
4. Is it clear whether or not the emissions were controlled (or not controlled)?		

Form filled out by____

Date ______________________________

INDICATE WHETHER ANSWER IS YES OR NO WITH AN "X" IN APPROPRIATE BOX.

IF ALL ANSWERS ARE "YES" PROCEED TO **METHODOLOGY/DETAIL CRITERIA CHECKLIST**.

APPENDIX B

MARKED-UP 1986 AP-42 SECTION 1.4

Natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium).

1.4 NATURAL GAS COMBUSTION

1.4.1 General[1-2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for power generation, for industrial process steam and heat production, and for domestic and commercial space heating. The primary component of natural gas is methane, although varying amounts of ethane and smaller amounts of nitrogen, helium and carbon dioxide are also present. Gas processing plants are required for recovery of liquefiable constitutents and removal of hydrogen sulfide (H_2S) before the gas is used (see Natural Gas Processing, Section 9.2). The average gross heating value of natural gas is approximately 9350 kilocalories per standard cubic meter (1050 British thermal units/standard cubic foot), usually varying from 8900 to 9800 kcal/scm (1000 to 1100 Btu/scf).

1.4.2 Emission And Controls[3-26]

Even though natural gas is considered to be a relatively clean fuel, some emissions can occur from the combustion reaction. For example, improper operating conditions, including poor mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide and hydrocarbons. Moreover, because a sulfur-containing mercaptan is added to natural gas to permit detection, small amounts of sulfur oxides will also be produced in the combustion process.

Nitrogen oxides are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions are functions of combustion chamber temperature and combustion product cooling rate. Emission levels vary considerably with the type and size of unit and with operating conditions, particularly combustion air temperature, load, and excess air level in boilers.

In some large boilers, several operating modifications may be used for NO control. Staged combustion, for example, including off-stoichiometric firing and/or two stage combustion, can reduce emissions by 5 to 50 percent.[26] In off stoichiometric firing, also called "biased firing", some burners are operated fuel rich, some fuel lean, and others may supply air only. In two stage combustion, the burners are operated fuel rich (by introducing only 70 to 90 percent stoichiometric air), with combustion being completed by air injected above the flame zone through second stage "NO ports". In staged combustion, NO_x emissions are reduced because the bulk of combustion occurs under fuel rich conditions.

Other NO_x reducing modifications include low excess air firing and flue gas recirculation. In low excess air firing, excess air levels are kept as low as possible without producing unacceptable levels of unburned combustibles (carbon monoxide, volatile organic compounds and smoke) and/or other operating problems. This technique can reduce NO_x emissions 5 to 35 percent, primarily because of lack of oxygen during combustion. Flue gas recirculation into the primary combustion zone, because the flue gas is relatively cool and oxygen deficient, can also lower NO_x emissions 4 to 85 percent, depending on the amount of gas recirculated. Flue gas recirculation is best suited for new boilers. Retrofit application would require extensive burner modifications.

See new section discussion of controls

depend primarily on the peak temperature within the combustion chamber as well as the oxygen concentration, nitrogen concentration, and time of exposure at peak temperature

TABLE 1.4-1. UNCONTROLLED EMISSION FACTORS FOR NATURAL GAS COMBUSTION[a]

Furnace size & type (10^6 Btu/hr heat input)	Particulate[b]		Sulfur dioxide[c]		Nitrogen oxides[d,e]		Carbon monoxide[f,g]		Volatile organics			
									Nonmethane		Methane	
	kg/10^{6}m^3	lb/10^6 ft^3	kg/10^{6}m^3	lb/10^6 ft^3	kg/10^{6}m^3	lb/10^6 ft^3	kg/10^{6}m^3	lb/10^6 ft^3	kg/10^{6}m^3	lb/10^6 ft^3	kg/10^{6}m^3	lb/10^6 ft^3
Utility boilers (> 100)	16 - 80	1 - 5	9.6	0.6	8800[h]	550[h]	640	40	23	1.4	4.8	0.3
Industrial boilers (10 - 100)	16 - 80	1 - 5	9.6	0.6	2240	140	560	35	44	2.8	48	3
Domestic and commercial boilers (< 10)	16 - 80	1 - 5	9.6	0.6	1600	100	320	20	84	5.3	43	2.7

[a]Expressed as weight/volume fuel fired.
[b]References 15-18.
[c]Reference 4. Based on avg. sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).
[d]References 4-5, 7-8, 11, 14, 18-19, 21.
[e]Expressed as NO_2. Tests indicate about 95 weight % NO_x is NO_2.
[f]References 4, 7-8, 16, 18, 22-25.
[g]References 16, 18. May increase 10 - 100 times with improper operation or maintenance.
[h]For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. For potential NO_x reductions by combustion modification, see text. Note that NO_x reduction from these modifications will also occur at reduced load conditions.

See new table

Studies indicate that low NO_x burners (20 to 50 percent reduction) and ammonia injection (40 to 70 percent reduction) also offer NO_x emission reductions.

Combinations of the above combustion modifications may also be employed to reduce NO_x emissions further. In some boilers, for instance, NO_x reductions as high as 70 to 90 percent have been produced by employing several of these techiques simultaneously. In general, however, because the net effect of any of these combinations varies greatly, it is difficult to predict what the reductions will be in individual applications.

Although not measured, all particulate has been estimated to be less than 1 micrometer in size.[27] Emission factors for natural gas combustion are presented in Table 1.4-1, and factor ratings in Table 1.4-2.

TABLE 1.4-2. FACTOR RATINGS FOR NATURAL GAS COMBUSTION

Furnace type	Particulate	Sulfur oxides	Nitrogen oxides	Carbon monoxide	Volatile organics	
					Nonmethane	Methane
Utility boiler	B	A	A	A	C	C
Industrial boiler	B	A	A	A	C	C
Commercial boiler	B	A	A	A	D	D
Residential furnace	B	A	A	A	D	D

See new table

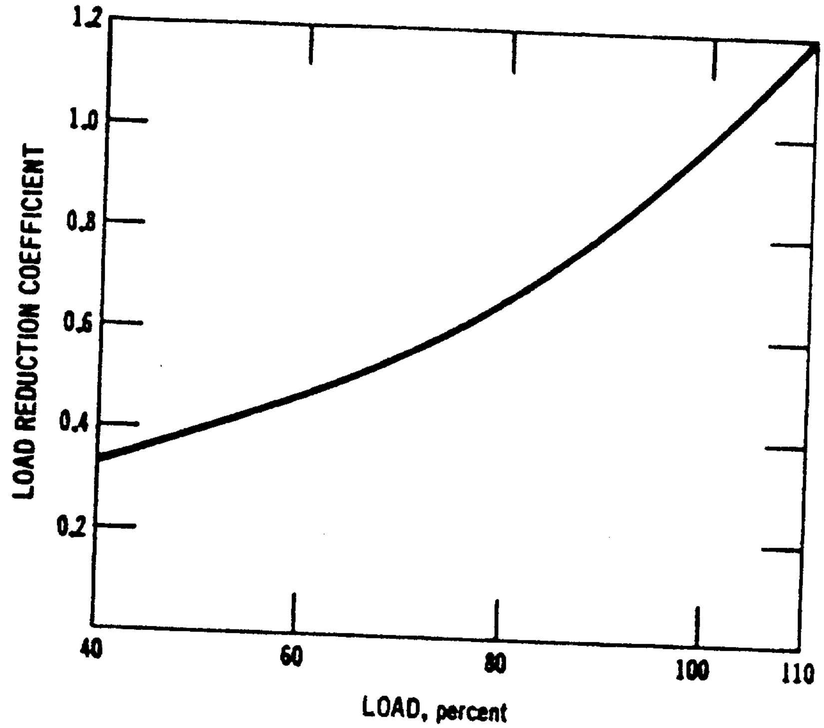

Figure 1.4-1. Load reduction coefficient as function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

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