ENVIRONMENTAL INFORMATION

Questar is committed to protecting the environment and improving the quality of life in communities where it has operations. By promoting the use of natural gas, one of the cleanest burning fuels available, Questar helps reduce negative effects on the environment. In addition, the company works to reduce environmental impacts of producing, transporting and distributing natural gas.

As a service to our large industrial customers we are providing technical air-quality and pollutant information associated with natural gas and other industrial process fuels.

- Air Quality - Emission Tools

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    - Fuel Oil Pollutants
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    - Residual Oil - Particle Size, Utility Boilers
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AIR QUALITY - EMISSIONS

Introduction

1. Emission Calculations

Emission factors and emission inventories have long been fundamental tools for air quality management. Emission estimates are important for developing emission control strategies, determining applicability of permitting and control programs, ascertaining the effects of sources and appropriate mitigation strategies, and a number of other related applications by an array of users, including federal, state, and local agencies, consultants, and industry. Data from source-specific emission tests or continuous emission monitors are usually preferred for estimating a source=s emissions because those data provide the best representation of the tested source=s emission. However, test data from individual sources are not always available and, even then, they may not reflect the variability of actual emission over time. Thus, emission factors are frequently the best or only method available for estimating emissions, in spite of their limitations.

The passage of the *Clean Air Act Amendments Of 1990 (CAAA)* and the *Emergency Planning And Community Right-To-Know Act (EPCRA)* of 1986 has increased the need for both criteria and Hazardous air pollutant (HAP) emission factors and inventories. The Emission Factor and Inventory Group (EFIG), in the U.S. Environmental Protection Agency=s (EPA) Office of Air Quality Planning and Standards (OAQPS), develops and maintains emission estimating tools to support the many activities mentioned above. The AP-42 series is the principal means by which EFIG can document its emission factors. These factors are cited in numerous other EPA publications and electronic databases, but without the process details and supporting reference material provided in AP-42.

2. What Is An AP-42 Emission Factor?

An emission factor is a **representative value** that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e.g., pounds of particulate emitted per million Btu of natural gas burned). Such factors facilitate estimation of emission from various sources of air pollution. In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average).

The general equation for emission estimation is:

$$E = A \times EF \times (1 - ER/100)$$

where:

E = emissions,
A = activity rate,
EF = emission factor, and
ER = overall emission reduction efficiency, %. ER is further defined as the product of the control device destruction or removal efficiency and the capture efficiency of the control system. When estimating emissions for a long time period (e.g., one year), both the device and the capture efficiency terms should account for upset periods as well as routing operations.

The fact that an emission factor for a pollutant of process is not available from EPA does not imply that the Agency believes the source does not emit that pollutant or that the source should not be inventoried. It is only that EPA does not have enough data to provide any advice.

3. Uses Of Emission Factors

Emission factors may be appropriate to use in a number of situations such as making source-specific emission estimates for area-wide inventories. These inventories have many purposes including ambient dispersion modeling and analysis, control strategy development, and in screening sources for compliance investigations. Emission factor use may also be appropriate in some permitting applications, such as in applicability determinations and in establishing operating permit fees.

Emission factors in AP-42 are neither EPA recommended emission limits (e.g., best available control technology or BACT, or lowest achievable emission rate or LAER) nor standards (e.g., National Emission Standard for Hazardous Air Pollutants or NESHAP, or New Source Performance Standards or NSPS). Use of these factors as source-specific permit limits and/or as emission regulation compliance determinations is not recommended by EPA. Because emission factors essentially represent an average of a range of emission rates, approximately half of the subject sources will have emission rates greater than the emission factor and the other half will have emission rates less than the factor. As such, a permit limit using an AP-42 emission factor would result in half of the sources being in noncompliance.

Also, for some sources, emission factors may be presented for facilities having air pollution control equipment in place. Factors noted as being influenced by control technology do not necessarily reflect the best available of state-of-the-art controls, but rather reflect the level of (typical) control for which data were available at the time the information was published. Sources often are tested more frequently when they are new and when they are believed to be operating properly, and either situation may bias the results.

Boiler Combustion Data

Fuel Oil Combustion

a. General

Two major categories of the fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; No.s 5 and 6 being residual oils; and No. 4 either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) must be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

b. Emissions

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and noncriteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO_2) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

Point source emissions of nitrogen oxides (NO_x), SO_2, PM, and carbon monoxide (CO) are being evaluated as criteria pollutants (those emissions for which National Primary and Secondary Ambient Air Quality Standards have been established). Particulate matter emissions are sometimes reported as total suspended particulate (TSP). More recent data generally quantify the portion of inhalable PM that is considered to be less than 10 micrometers in aerodynamic diameter (PM-10). In addition to the criteria pollutants, this section includes point source emissions of some noncriteria pollutants, nitrous oxide (N_2O), volatile organic compounds (VOCs), and hazardous air pollutants (HAPs), as well as data on particle size distribution to support PM-10 emission inventory efforts. Emissions of carbon dioxide (CO_2) are also being considered because of its possible participation in global climatic change and the corresponding interest in including this gas in emission inventories. Most of the carbon in fossil fuels is emitted as CO_2 during combustion. Minor amounts of carbon are emitted as CO, much of which ultimately oxidizes to CO_2 or as carbon in the ash. Finally, fugitive emissions associated with the use of oil at the combustion source are being included in this section.

CRITERIA POLLUTANT EMISSION FACTORS

FOR UNCONTROLLED FUEL OIL COMBUSTION

Firing Configuration	SO_2 [a] lb/10^3 gal	SO_3 lb/10^3 gal	NO_x [b] lb/10^3 gal	CO [c, d] lb/10^3 gal	Filterable PM [e, f] lb/10^3 gal
Utility boilers					
No. 6 oil fired, normal firing	157S	5.7S	67	5	9.19(S)+3.22
No. 6 oil fired, tangential firing	157S	5.7S	42	5	9.19(S)+3.22
No. 5 oil fired, normal firing	157S	5.7S	67	5	10
No. 5 oil fired, tangential firing	157S	5.7S	42	5	10
No. 4 oil fired, normal firing	150S	5.7S	67	5	7
No. 4 oil fired, tangential firing	150S	5.7S	42	5	7
Industrial boilers					
No. 6 oil fired	157S	2S	55	5	9.19(S)+3.22
No. 5 oil fire	157S	2S	55	5	10
Distillate oil fired	142S	2S	20	5	2
No. 4 oil fired	150S	2S	20	5	7
Commercial/institutional/residential combustors					
No. 6 oil fired	157S	2S	55	5	9.19(S)+3.22
No. 5 oil fired	157S	2S	55	5	10
Distillate oil fire	142S	2S	20	5	2
No. 4 oil fired	150S	2S	20	5	7
Residential furnace	142S	2S	18	5	3

[a] S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1.0% sulfur, then S equals 1.0.

[b] Expressed as NO_2. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 lb/10^3 gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO_2 /10^3 gal = 20.54 + 104.39(N), where N is the weight percent of nitrogen in the oil. For example, if the fuel is 1.0% Nitrogen, then N equals 1.0.

[c] CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[d] Emission factors for CO_2 from oil combustion should be calculated using lb CO_2 /10^3 gal oil = 259 C (distillate) or 288 C (residual). C equals the weight percent carbon in the fuel. For example, if the fuel is 86% carbon, then C equals 86.

[e] Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. PM-10 values include the sum of that particulate collected on the PM-10 filter of an EPA Method 201 or201A sampling train and condensable emission as measured by EPA Method 202.

[f] Particulate emission factors for residual oil combustion are, on average, a function of fuel oil grade and sulfur content: where S is the weight % of sulfur in oil. For example, if the fuel is 1.0% sulfur, then S equals 1.0.

EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE AND NONMETHANE TOC (NMTOC)

FROM UNCONTROLLED FUEL OIL COMBUSTION

Firing Configuration	TOC lb/10^3 gal	Methane lb/10^3 gal	NMTOC lb/10^3 gal
Utility boilers			
No. 6 oil fired, normal firing	1.04	0.28	0.76
No. 6 oil fired, tangential firing	1.04	0.28	0.76
No. 5 oil fired, normal firing	1.04	0.28	0.76
No. 5 oil fired, tangential firing	1.04	0.28	0.76
No. 4 oil fired, normal firing	1.04	0.28	0.76
No. 4 oil fired, tangential firing	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired	1.28	1.0	0.28
No. 5 oil fired	1.28	1.0	0.28
Distillate oil fired	0.252	0.052	0.2
No. 4 oil fired	0.252	0.052	0.2
Commercial/ institutional/residential combustors			
No. 6 oil fired	1.605	0.475	1.13
No. 5 oil fired	1.605	0.475	1.13
Distillate oil fired	0.556	0.216	0.34
No. 4 oil fired	0.556	0.216	0.34
Residential furnace	2.493	1.78	0.713

CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS

FOR UTILITY BOILERS FIRING RESIDUAL OIL

Cumulative Mass % Stated Size				Cumulative Emission Factor (lb/10^3 gal)		
Particle Size[b]		Controlled		Uncontrolled[c]	ESP Controlled[d]	Scrubber Controlled[e]
(µm)	Uncontrolled	ESP[a]	Scrubber	Factor	Factor	Factor
15	80	75	100	6.7A	0.05A	.050A
10	71	63	100	5.9A	0.042A	0.050A
6	58	52	100	4.8A	0.035A	0.50A
2.5	52	41	97	4.3A	0.028A	0.48A
1.25	43	31	91	3.6A	0.021A	0.46A
1.00	39	28	84	3.3A	0.018A	0.42A
0.625	20	20	64	1.74	0.007A	0.32A
TOTAL	100	100	100	8.3A	0.067A	0.50A

[a] ESP = electrostatic precipitator

[b] Expressed as aerodynamic equivalent diameter.

[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil
grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.0% sulfur, then S equals 1.0.

No. 6 oil: $A = 1.12(S) + 0.37$ kg/10^3 L,

No. 5 oil: $A = 1.2$ kg/10^3 L

No. 4 oil: $A = 0.84$ kg/10^3 L

[d] Estimated control efficiency for ESP is 99.2%.

[e] Estimated control efficiency for scrubber is 94%.

CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS

FOR INDUSTRIAL BOILERS FIRING RESIDUAL OIL

	Cumulative Mass % Stated Size		Cumulative Emission Factor[b] (lb/10^3 gal)	
Particle Size[a] (µm)	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled Factor	Multiple Cyclone Controlled[d] Factor
15	91	100	7.59A	1.67A
10	86	95	7.17A	1.58A
6	77	72	6.42A	1.17A
2.5	56	22	4.67A	0.33A
1.25	39	21	3.25A	0.33A
1.00	36	21	3.00A	0.33A
0.625	30	___[c]	2.50A	___[c]
TOTAL	100	100	8.34A	1.67A

[a] Expressed as aerodynamic equivalent diameter.

[b] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.0% sulfur, then S equals 1.0.

No. 6 oil: A = 1.12(S) + 0.37 kg/10^3 L,

No. 5 oil: A = 1.2 kg/10^3 L

No. 4 oil: A = 0.84 kg/10^3 L

[c] Insufficient data. [d] Estimated control efficiency for multiple cyclone is 80%.

CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS

FOR UNCONTROLLED INDUSTRIAL BOILERS FIRING DISTILLATE OIL

Particle Size (µm)	Cumulative Mass % Stated Size Uncontrolled	Cumulative Emission Factor (lb/10^3 gal) Uncontrolled
15	68	1.33
10	50	1.00
6	30	0.58
2.5	12	0.25
1.25	9	0.17
1.00	8	0.17
0.625	2	0.04
TOTAL	100	2.00

Boiler Combustion Data

Natural Gas Combustion

a. General

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. The average gross heating value of natural gas is approximately 1000 British thermal units per standard cubic foot, usually varying from 900 to 1100 Btu/scf.

b. Emissions And Controls

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 oxides emissions depend primarily on the peak temperature within the combustion chamber as well as the furnace-zone 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 are 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 are 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 is made up of combustion products which act as inerts during combustion of the flue/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 emission 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 condensable fractions, based on the EPA sampling method. Filterable and condensable emission rates are of the same order of magnitude for boilers; for residential furnaces, most of the PM is in the form of condensable 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 PARTICULATE MATTER (PM) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input)	Filterable PM[b] lb/10^6 ft^3	Condensable PM[c] lb/10^6 ft^3
Utility/large industrial boilers (>100)	1 - 5	ND
Small industrial boilers (10 - 100)	6.2	7.5
Commercial boilers (0.3 - <10)	4.5	7.5
Residential furnaces (<0.3)	0.18	11

[a] All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters natural gas fired and lb of pollutant/10^6 cubic feet natural gas fired. 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.

ND = no data.

[b] Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[c] Condensable PM is that particulate matter collected using EPA Method 202 (or equivalent). Total PM is the sum of the filterable

PM and condensable PM. All PM emissions can be assumes to be less than 10 micrometers in aerodynamic equivalent diameter (PM-10).

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)	SO_2 lb/10^6 ft ^{3}	NO_x lb/10^6 ft ^{3}	CO lb/10^6 ft ^{3}
Utility/large Industrial Boilers (>100)			
Uncontrolled	0.6	550	40
Controlled – Low NO_x burners	0.6	81	ND
Controlled – Flue gas recirculation	0.6	53	ND
Small Industrial Boilers (10 - 100)			
Uncontrolled	0.6	140	35
Controlled – Low NO_x burners	0.6	81	61
Controlled – Flue gas recirculation	0.6	30	37
Commercial Boilers (0.3 - <10)			
Uncontrolled	0.6	100	21
Controlled – Low NO_x burners	0.6	17	15
Controlled – Flue gas recirculation	0.6	36	ND
Residential Furnaces (<0.3)			
Uncontrolled	0.6	94	40

[a] Units are kg of pollutant/10^6 cubic meters natural gas fired and lb of pollutant/10^6 cubic feet natural gas fired. Based on an average natural gas fired higher heating value of 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.

ND = no data.

EMISSION FACTORS

FOR CARBON DIOXIDE (CO_2) AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION

Combustor Type (Size, 10^6 Btu/hr Heat Input)	CO_2 lb/10^6 ft ^{3}	TOC lb/10^6 ft ^{3}
Utility/large industrial boilers (>100)	ND	1.7
Small industiral boilers (10 - 100)	1.2 E + 05	5.8
Commercial boilers (0.3 - <10)	1.2 E + 05	8.0
Residential furnaces	1.3 E + 05	11

Boiler Combustion Data

Bituminous and Subbituminous Coal Combustion

a. General

Coal is a complex combination of organic matter and inorganic ash formed over eons from successive layers of fallen vegetation. Coal types are broadly classified as anthracite, bituminous, subbituminous or lignite. These classifications are based on coal-heating value together with relative amounts of fixed carbon, volatile matter, ash, sulfur and moisture.

There are three major combustion techniques: suspension firing, grate firing and fluidized- bed combustion. Suspension firing is the primary combustion mechanism in pulverized coal and cyclone systems. Grate firing is the primary mechanism in underfeed and overfeed stokers. Both mechanisms are employed in spreader stokers. Fluidized-bed combustion, while not constituting a significant percentage of the total boiler population, has nonetheless gained popularity in the last decade and today generates steam for industries, cogenerators, independent power producers and utilities.

Pulverized coal furnaces are used primarily in utility and large industrial boilers. In these systems, the coal is pulverized in a mill to the consistency of talcum powder (i.e., at least 70 percent of the particles will pass through a 200-mesh sieve). The pulverized coal is generally entrained in primary air before being fed through burners to the furnace, where it is fired in suspension. Pulverized coal furnaces are classified as either dry or wet bottom, depending on the ash-removal technique. Dry bottom furnaces fire coals with high ash- fusion temperatures and use dry ash removal techniques. In wet-bottom (or slag-tap) furnaces, coals with low-ash fusion temperatures are combusted and molten ash is drained from the bottom of the furnace. Pulverized coal furnaces are further classified by the firing position of the burners, i.e., single (front or rear) wall, horizontally opposed, vertical or tangential (corner-fired). Wall-fired boilers can be either single wall-fired (with burners on only one wall of the furnace firing horizontally) or opposed wall-fired (with burners mounted on two opposing walls). Tangentially fired boilers have burners mounted in the corners of the furnace. The fuel and air are injected toward the center of the furnace to create a vortex that enhances air and fuel mixing.

Cyclone furnaces burn low ash-fusion temperature coal which has been crushed to below 4-mesh particle size. The coal is fed tangentially in a stream of primary air to a horizontal cylindrical furnace. Within the furnace, small coal particles are burned in suspension while larger particles are forced against the outer wall. Because of the high temperatures developed in the relatively small furnace volume, and because of the low fusion temperature of the coal ash, much of the ash forms a liquid slag on the furnace walls. The slag drains from the walls to the bottom of the furnace where it is removed through a slag tap opening. Cyclone furnaces are used mostly in utility and large industrial applications.

In spreader stokers, a flipping mechanism throws the coal into the furnace and onto a moving fuel bed. Combustion occurs partly in suspension and partly on the grate. Because of significant carbon content in the particulate, fly-ash reinjection from mechanical collectors is commonly employed to improve boiler efficiency. Ash residue from the fuel bed is deposited in a receiving pit at the end of the grate.

In overfeed stokers, coal is fed onto a traveling or vibrating grate and burns on the fuel-bed as it progresses through the furnace. Ash particles fall into an ash pit at the rear of the stoker. The term Aoverfeed@ applies because the coal is fed onto the moving grate under an adjustable gate. Conversely, in Aunderfeed@ stokers, coal is fed into the firing zone from below by mechanical rams or screw conveyors. The coal moves in a channel, known as a retort, from which it is forced upward, spilling over the top of each side to form and to feed the fuel-bed. Combustion is completed by the time the bed reaches the side dump grates, from which the ash is discharged into shallow pits. Underfeed stokers include single retort units and multiple retort units, the latter having several retorts side by side.

Small hand-fired boilers and furnaces are sometimes found in small industrial, commercial, institutional, or residential applications. In most hand-fired units, the fuel is primarily burned in layers on the bottom of the furnace or on a grate. From an emissions standpoint, hand-fired units generally have higher carbon monoxide (CO) and volatile organic compounds (VOC) emissions than larger boilers because of their lower combustion efficiencies.

In a fluidized bed combustor (FBC), the coal is introduced to a bed of either sorbent (limestone or dolomite) or inert material (usually sand) which is fluidized by an upward flow of air. Most of the combustion occurs within the bed, but some smaller particles burn above the bed in the Afreeboard@ space. The two principal types of atmospheric FBC boilers are bubbling bed and circulating bed. The fundamental distinguishing feature between these types is the fluidization velocity. In the bubbling bed design, the fluidization velocity is relatively low, ranging between 1.5 and 4 m/sec (5 and 12 ft/sec), in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ fluidization velocities as high as 9 m/sec (30 ft/sec) to promote the carryover or circulation of solids. High-temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high-volume recycle rate which increases the fuel residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiency and better sorbent utilization than bubbling bed units.

b. Emissions and Controls

The major pollutants of concern from bituminous and subbituminous coal combustion are particulate matter (PM), sulfur oxides (SO_2) and nitrogen oxides (NO_x). Emissions from coal combustion depend on the rank and composition of the fuel, the type and size of the boiler, firing conditions, load, type of control technologies, and the level of equipment maintenance. Some unburnt combustibles, including numerous organic compounds and CO, are generally emitted even under proper boiler conditions.

Particulate matter composition and emission levels are a complex function of firing configuration, boiler operation, and coal properties. In pulverized coal systems, combustion is almost complete, and thus emitted particulate is largely comprised of inorganic ash residues. In wet bottom pulverized coal units and cyclones, the quantity of ash leaving the boiler is lower than in dry bottom units, because some of the ash liquefies, collects on the furnace walls, and drains from the furnace bottom as molten slag.

Industrial Engine Combustion Data

Stationary Gas Turbines for Electricity Generation

a. General

Stationary gas turbines are applied in electric power generators, in gas pipeline pump and compressor drives, and in various process industries. Gas turbines greater than 4021 horsepower (electric) or 3 megawatts (electric) are used in electrical generation for continuous, peaking or standby power. The primary fuels used are natural gas and distillate (No. 2) fuel oil, although residual fuel oil is used in a few applications.

b. Emissions and Controls

Emission control technologies for gas turbines have advanced to a point where all new and most existing units are complying with various levels of specified emission limits. For these sources, the emission factors become an operational specification rather than a parameter to be quantified by testing. This section treats uncontrolled (i.e., baseline) emission and controlled emissions with specific control technologies.

The emission factors presented are for simple cycle gas turbines. These factors also apply to cogeneration/combined cycle gas turbines. In general, if the heat recovery steam generator (HRSG) is not supplementary fired, the simple cycle input-specific emission factors pounds per million British thermal unit (lb/MMBtu) will apply to cogeneration/combined cycle systems. The output-specific emissions pounds per horsepower-hour (lb/hp-hr) will decrease according to the ratio of simple cycle to combined cycle power output. If the HRSG is supplementary fired, the emissions and fuel usage must be considered to estimate stack emissions. Nitrogen oxides (NO_x) emission from regenerative cycle turbines (which account for only a small percentage of turbines in use) are greater than emissions from simple cycle turbines because of the increased combustion air temperature entering the turbine. The carbon monoxide (CO) and total organic compounds (TOC) emissions may be lower with the regenerative system for a comparable design. More power is produced from the same energy input, so the input-specific emissions factor will be affected by changes in emissions, while output-specific emission will reflect the increased power output.

Water/steam injection is the most prevalent NO_x control for cogeneration/combined cycle gas turbines. The water or steam is injected with the air and fuel into the turbine combustion to lower the peak temperatures that, in turn, decreases the thermal NO_x produced. The lower average temperature within the combustor may produce higher levels of CO and TOCs as a result of incomplete combustion.

Selective catalytic reduction (SCR) is a postcombustion control that selectively reduces NO_x by reaction of ammonia (NH_3) and NO_x on a catalytic surface to form nitrogen gas (N_2) and water (H_2O). Although SCR systems can be used alone, all existing applications of SCR have been used in conjunction with water/steam injection controls. For optimum SCR operation, the flue gas must be within a temperature range of 315 - 426EC (600 - 800EF) with the precise limits dependent on the catalyst. Some SCR systems also utilize a CO catalyst to give simultaneous catalytic CO/NO_x control.

Advanced combustor can designs are currently being phased into production turbines. These dry techniques decrease turbine emissions by modifying the combustion mixing, air staging, and flame stabilization to allow operation at a much leaner air/fuel ration relative to normal operation. Operation at leaner conditions will lower peak temperatures within the primary flame zone of the combustor. The lower temperatures may also increase CO and TOC emissions.

With the proliferation and advancement of NO_x control technologies for gas turbines during the past 15 years, the emission factors for the installed gas turbine population are quite different than those for uncontrolled turbines. However, uncontrolled turbine emissions have not changed significantly. Therefore a careful review of specific turbine details should be performed before applying uncontrolled emission factors. Today, most gas turbines are controlled to meet local, state, and/or federal regulations.

Gas turbines firing distillate or residual oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel should be used for flue gas emission factors assuming all metals pass through the turbine.

EMISSION FACTORS

FOR LARGE UNCONTROLLED GAS TURBINES[a]

	Natural Gas		Fuel Oil (Distillates)	
	lb/hp-hr	lb/MMBtu	lb/hp-hr	lb/MMBtu
Pollutant	(power output)	(fuel input)	(power output)	(fuel input)
NO_x	3.53 E-03	0.44	5.60 E-03	0.698
CO	8.60 E-04	0.11	3.84 E-04	0.048
CO_2[a]	0.897	112	1.31	164
TOC (as methane)	1.92 E-04	0.024	1.37 E-04	0.017
SO_x[b]	7.50 E-03S	0.94S	8.09 E-03S	1.01S
PM-10				
Solids	1.54 E-04	0.0193	3.04 E-04	0.038
Condensables	1.81 E-04	0.0226	1.85 E-04	0.023
Sizing %				
<0.05µm	15%	15%	16%	16%
<0.10µm	40%	40%	48%	48%
<0.15µm	63%	63%	72%	72%
<0.20µm	78%	78%	85%	85%
<0.25µm	89%	89%	93%	93%
<1µm	100%	100%	100%	100%

[a] Based on 100% conversion of the fuel carbon to CO_2. CO_2 (lb/MMBtu) = 3.67*C/E, where C = carbon content of fuel by weight (0.75), and E = energy content of fuel, (0.0239 MMBtu/lb).

The uncontrolled CO_2 emission factors are also applicable to controlled gas turbines.

[b] All sulfur in the fuel is assumed to be converted to SO_2. S = % sulfur in fuel. When sulfur content is not available, 0.6 lb/10^6 ft ^{3} (0.0006 lb/MMBtu) can be used; however, the equation is more accurate.

EMISSION FACTORS

FOR LARGE GAS-FIRED CONTROLLED GAS TURBINES

	Water Injection (.08 water/fuel ratio)		Steam Injection (1.2 water/fuel ratio)		Selective Catalytic Reduction (with water injection)
Pollutant	lb/hp-hr (power output)	lb/MMBtu (fuel input)	lb/hp-hr (power output)	lb/MMBtu (fuel input)	lb/MMBtu (fuel input)
NO_x	1.10 E-03	0.14	9.70 E-04	0.12	0.03
CO	2.07 E-03	0.28	1.17 E-03	0.16	0.0084
TOC (as methane)	ND	ND	ND	ND	0.014
NH_3	ND	ND	ND	ND	0.0065
NMHC	ND	ND	ND	ND	0.0032
Formaldehyde	ND	ND	ND	ND	0.0027

EMISSION FACTORS

FOR LARGE DISTILLATE OIL-FIRED CONTROLLED GAS TURBINES

Pollutant	Water Injection (0.8 water/fuel ratio)	
	lb/hp-hr (power output)	lb/MMBtu (fuel input)
NO_x	2.31 E-03	0.290
CO	1.48 E-04	0.0192
TOC (as methane)	3.75 E-05	0.0048
SO_x	——	——
PM-10[a]	2.98 E-04	0.0372

[a] All PM is . 1 µm in size.

Industrial Engine Combustion Data

Heavy-duty Natural Gas-fired Pipeline Compressor Engines

a. General

Engines in the natural gas industry are used primarily to power compressors used for pipeline transportation, field gathering (collecting gas from wells), underground storage, and gas processing plant applications, i.e., prime movers. Pipeline engines are concentrated in the major gas-producing states (such as those along the Gulf Coast) and along the major gas pipelines. Gas turbines emit considerably smaller amounts of pollutants than do reciprocating engines; however, reciprocating engines are generally more efficient in their use of fuel.

Reciprocating engines are separated into 3 design classes: 2-cycle (stroke) lean burn, 4-stroke lean burn, and 4-stroke rich burn. Each of these have design differences that affect both baseline emissions as well as the potential for emissions control. Two-stroke engines complete the power cycle in a single engine revolution compared to 2 revolutions for 4-stroke engines. With the 2-stroke engine, the air/fuel charge is injected with the piston near the bottom of the power stroke. The valves are all covered or closed, and the piston moves to the top of the cylinder compressing the charge. Following ignition and combustion, the power stroke starts with the downward movement of the piston. Exhaust ports or valves are then uncovered to remove the combustion products, and a new air/fuel charge is ingested. Two-stroke engines may be turbocharged using an exhaust-powered turbine to pressurize the charge for injection into the cylinder. Non-turbocharged engines may be either blower scavenged or piston scavenged to improve removal of combustion products.

Four-stroke engines use a separate engine revolution for the intake/compression stroke and the power/exhaust stroke. These engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or turbocharged, using a turbine to pressurize the charge. Turbocharged units produce a higher power output for a given engine displacement, whereas naturally aspirated units have lower initial cost and maintenance. Rich burn engines operate near the air/fuel stoichiometric limit with exhaust excess oxygen levels less than 4 percent. Lean burn engines may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12 percent or greater. Pipeline population statistics show a nearly equal installed capacity of turbines and reciprocating engines. For reciprocating engines, 2-stroke designs contribute approximately two-thirds of installed capacity.

b. Emissions and Controls

The primary pollutant of concern is nitrogen oxide (NO_x), which readily forms in the high-temperature, pressure, and excess air environment found in natural gas-fired compressor engines. Lesser amounts of carbon monoxide (CO) and total organic compounds (TOC) are emitted, although for each unit of natural gas burned, compressor engines (particularly reciprocating engines) emit significantly more of these pollutants than do external combustion boilers. Sulfur oxide emissions are proportional to the sulfur content of the fuel and will usually be quite low because of the negligible sulfur content of most pipeline gas.

This section will also discuss the major variables affecting NO_x emissions and the various control technologies that will reduce uncontrolled NO_x emissions.

The major variables affecting NO_x emissions from compressor engines include the air/fuel ration, engine load (defined as the ratio of the operating horsepower to the rated horsepower), intake (manifold) air temperature, and absolute humidity. In general, NO_x emissions increase with increasing load and intake air temperature, and decrease with increasing absolute humidity and air/fuel ratio (the latter already being, in most compressor engines, on the Alean@ side of that air/fuel ratio at which maximum NO_x formation occurs).

Because NO_x is the primary pollutant of significance emitted from pipeline compressor engines, control measure to date have been directed mainly at limiting NO_x emissions. For gas turbines, the early control applications used water or steam injection. New applications of dry low NO_x combustor can designs and selective catalytic reduction (SCR) are appearing. Water injection has achieved reductions of 70 to 80 percent with utility gas turbines. Efficiency penalties of 2 to 3 percent are typical due to the added heat load of the water. Turbine power outputs typically increase, however. Steam injection may also be used, but the resulting NO_x reductions may not be as great as with water injection, and it has the added disadvantage that a supply of steam must be readily available. Water injection has not been applied to pipeline compressor engines because of the lack of water availability.

The efficiency penalty and operational impacts associated with water injection have led manufacturers to develop dry low NO_x combustor can designs based on lean burn and/or staging to suppress NO_x formation. These are entering the market in the early 1990s. Stringent gas turbine NO_x limits have been achieved in California in the late 1980s with SCR. This is an ammonia-based postcombustion technology that can achieve in excess of 80 percent NO_x reductions. Water or steam injection is frequently used in combination with SCR to minimize ammonia costs.

For reciprocating engines, both combustion controls and postcombustion catalytic reduction have been developed. Controlled rich burn engines have mostly been equipped with non-SCR (NSCR) that uses unreacted TOCs and CO to reduce NO_x by 80 to 90 percent. Some rich burn engines can be prestratified charge engines that reduce the peak flame temperature in the NO_x-forming regions. Lean burn engines have mostly met NO_x-reduction requirements with lean combustion controls using torch ignition or chamber redesign to enhance flame stability. NO_x reductions of 70 to 80 percent are typical for numerous engines with retrofit or new unit controls. Lean burn engines may also be controlled with SCR, but the operational problems associated with engine control under low NO_x operation have been a deterrent.

CRITERIA EMISSION FACTORS

FOR UNCONTROLLED NATURAL GAS PRIME MOVERS

	Gas Turbines		2-Cycle Lean Burn		4-Cycle Lean Burn		4-Cycle Rich Burn	
Pollutant	lb/hp-hr (power output)	lb/MMBtu (fuel input)	lb/hp-hr (power output)	lb/MMBtu (fuel input)	lb/hp-hr (power output)	lb/MMBtu (fuel input)	lb/hp-hr (power output)	lb/MMBtu (fuel input)
NO_x	2.87 E-03	0.34	0.024	2.7	0.026	3.2	0.022	2.3
CO	1.83 E-03	0.17	3.31 E-03	0.38	3.53 E-03	0.42	0.019	1.6
CO_2[a]	0.89	110	.089	110	0.89	110	0.89	110
TOC	3.97 E-04	0.053	0.013	1.5	0.011	1.2	2.65 E-03	0.27
TNMOC	2.20 E-05	0.002	9.48 E-04	0.11	1.59 E-03	0.18	3.09 E-04	0.03
CH_4	3.75 E-04	0.051	0.012	1.4	9.04 E-03	1.1	2.43 E-03	0.24

[a] EMISSION FACTOR RATING: B. Based on 100% conversion of the fuel carbon to CO_2. CO_2 (lb/MMBtu) = 3.67-C/E, where C = carbon content of fuel by weight (0.75), and E = energy content of fuel, 0.239 MMBtu/lb. The uncontrolled CO_2emission factors are also applicable to natural gas prime movers controlled by combustion modifications, NSCR, and SCR.

NON-CRITERIA EMISSION FACTORS

FOR UNCONTROLLED NATURAL GAS PRIME MOVERS

Pollutant	2-Cycle Lean Burn lb/hp-hr
Formaldehyde	2.93 E-03
Benzene	3.62 E-06
Toluene	3.62 E-06
Ethylbenzene	1.81 E-06
Xylenes	5.43 E-06

EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS:

COMBUSTION MODIFICATIONS ON 2-STROKE LEAN BURN ENGINE

	Baseline		Increased Air/Fuel Ratio With Intercooling	
Pollutant	lb/hp-hr	lb/MMBtu	lb/hp-hr	lb/MMBtu
NO_x	0.022	2.9	0.011	1.5
CO	2.07 E-03	0.28	3.31 E-03	0.46
TOC	0.017	2.2	0.019	2.6
TNMOC	0.011	1.6	0.013	1.8
CH_4	5.07 E-03	0.68	5.51 E-03	0.75
PM-10				
Total (front + back halves)	3.53 E-04	0.046	3.97 E-04	0.055
Solids (front half)	2.16 E-04	0.029	2.87 E-04	0.038
Condensables (back half)	1.26 E-04	0.017	1.28 E-04	0.017

EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS:

NSCR ON 4-CYCLE RICH BURN ENGINE

	Inlet		Outlet	
Pollutant	lb/hp-hr	lb/MMBtu	lb/hp-hr	lb/MMBtu
NO_x	0.017	1.8	5.51 E-03	0.58
CO	0.026	2.8	0.022	2.4
TOC	7.28 E-04	0.079	4.1 E-04	0.047
NH_3	1.10 E-04	0.012	1.81 E-03	0.19
C7 - C16	4.19 E-05	0.0042	9.04 E-06	0.0009
C16+	3.75 E-05	0.004	1.32 E-06	0.0001
PM solids (front half)	6.61 E-06	0.0007	6.61 E-06	0.0007
Benzene	ND	7.1 E-04	ND	1.1 E-04
Toluene	ND	2.3 E-04	ND	<2.3 E-05
Xylenes	ND	<5.9 E-05	ND	<4.0 E-05
Propylene	ND	<1.6 E-04	ND	<1.6 E-04
Naphthalene	ND	<4.9 E-05	ND	<4.9 E-05
Formaldehyde	ND	<1.6 E-03	ND	<7.2 E-06
Acetaldehyde	ND	<6.1 E-05	ND	<4.8 E-06
Acrolein	ND	<3.7 E-05	ND	<9.6 E-06

CONTROLLED EMISSION FACTORS FOR NATURAL GAS PRIME MOVERS:

SCR ON 4-CYCLE LEAN BURN ENGINE

Pollutant	Inlet		Outlet	
	lb/hp-hr	lb/MMBtu	lb/hp-hr	lb/MMBtu
NO_x	0.042	6.4	7.94E-03	1.2
CO	2.65 E-03	0.38	2.43 E-03	0.37
NH_3	ND	ND	5.95 E-04	0.091
C7 - C16	1.54 E-05	0.0023	6.83 E-06	0.0013
C16+	2.87 E-05	0.0044	5.29 E-06	0.0008

CONTROLLED EMISSION FACTORS FOR NATURAL GAS PRIME MOVERS:

CLEAN BURN AND PRECOMBUSTION CHAMBER ON 2-CYCLE LEAN BURN ENGINE

	Clean Burn		Precombustion Chamber	
Pollutant	lb/hp-hr	lb/MMBtu	lb/hp-hr	lb/MMBtu
NO_x	5.07 E-03	0.83	6.39 E-03	0.85
CO	2.43 E-03	0.30	5.29 E-03	0.67
TOC	5.51 E-03	0.77	0.014	1.8
TNMOC	2.65 E-04	0.15	0.94 E-03	0.25
CH_4	5.29 E-03	0.62	0.012	1.5