CHAPTER 18

COMBUSTION AND FUELS

PRINCIPLES OF COMBUSTION

COMBUSTION is a chemical reaction in which an oxidant reacts rapidly with a fuel to liberate stored energy as thermal energy, generally in the form of high-temperature gases. Small amounts of electromagnetic energy (light), electric energy (free ions and electrons), and mechanical energy (noise) are also produced during combustion. Except in special applications, the oxidant for combustion is oxygen in the air.

Conventional hydrocarbon fuels contain primarily hydrogen and carbon, in elemental form or in various compounds. Their complete combustion produces mainly carbon dioxide (CO_2) and water (H_2O); however, small quantities of carbon monoxide (CO) and partially reacted flue gas constituents (gases and liquid or solid aerosols) may form. Most conventional fuels also contain small amounts of sulfur, which is oxidized to sulfur dioxide (SO_2) or sulfur trioxide (SO_3) during combustion, and noncombustible substances such as mineral matter (ash), water, and inert gases. Flue gas is the product of complete or incomplete combustion and includes excess air (if present), but not dilution air.

Fuel combustion rate depends on (1) the rate of the chemical reaction of the combustible fuel constituents with oxygen, (2) the rate at which oxygen is supplied to the fuel (the mixing of air and fuel), and (3) the temperature in the combustion region. The reaction rate is fixed by fuel selection. Increasing the mixing rate or temperature increases the combustion rate.

With **complete combustion** of hydrocarbon fuels, all hydrogen and carbon in the fuel are oxidized to H_2O and CO_2. Generally, for complete combustion, excess oxygen or excess air must be supplied beyond the amount theoretically required to oxidize the fuel. Excess air is usually expressed as a percentage of the air required to completely oxidize the fuel.

In **stoichiometric combustion** of a hydrocarbon fuel, fuel is reacted with the exact amount of oxygen required to oxidize all carbon, hydrogen, and sulfur in the fuel to CO_2, H_2O, and SO_2. Therefore, exhaust gas from stoichiometric combustion theoretically contains no incompletely oxidized fuel constituents and no unreacted oxygen (i.e., no carbon monoxide and no excess air or oxygen). The percentage of CO_2 contained in products of stoichiometric combustion is the maximum attainable and is referred to as the **stoichiometric CO_2**, **ultimate CO_2**, or **maximum theoretical percentage of CO_2**.

Stoichiometric combustion is seldom realized in practice because of imperfect mixing and finite reaction rates. For economy and safety, most combustion equipment should operate with some excess air. This ensures that fuel is not wasted and that combustion is complete despite variations in fuel properties and in the supply rates of fuel and air. The amount of excess air to be supplied to any combustion equipment depends on (1) expected variations in fuel properties and in fuel and air supply rates, (2) equipment application, (3) degree of operator supervision required or available, and (4) control requirements. For maximum efficiency, combustion at low excess air is desirable.

Incomplete combustion occurs when a fuel element is not completely oxidized during combustion. For example, a hydrocarbon may not completely oxidize to carbon dioxide and water, but may form partially oxidized compounds, such as carbon monoxide, aldehydes, and ketones. Conditions that promote incomplete combustion include (1) insufficient air and fuel mixing (causing local fuel-rich and fuel-lean zones), (2) insufficient air supply to the flame (providing less than the required quantity of oxygen), (3) insufficient reactant residence time in the flame (preventing completion of combustion reactions), (4) flame impingement on a cold surface (quenching combustion reactions), or (5) flame temperature that is too low (slowing combustion reactions).

Incomplete combustion uses fuel inefficiently, can be hazardous because of carbon monoxide production, and contributes to air pollution.

Combustion Reactions

The reaction of oxygen with the combustible elements and compounds in fuels occurs according to fixed chemical principles, including

- Chemical reaction equations
- Law of matter conservation: the mass of each element in the reaction products must equal the mass of that element in the reactants
- Law of combining masses: chemical compounds are formed by elements combining in fixed mass relationships
- Chemical reaction rates

Oxygen for combustion is normally obtained from air, which is a physical mixture of nitrogen, oxygen, small amounts of water vapor, carbon dioxide, and inert gases. For practical combustion calculations, dry air consists of 20.95% oxygen and 79.05% inert gases (nitrogen, argon, and so forth) by volume, or 23.15% oxygen and 76.85% inert gases by mass. For calculation purposes, nitrogen is assumed to pass through the combustion process unchanged (although small quantities of nitrogen oxides form). Table 1 lists oxygen and air requirements for stoichiometric combustion and the products of stoichiometric combustion of some pure combustible materials (or constituents) found in common fuels.

Flammability Limits

Fuel burns in a self-sustained reaction only when the volume percentages of fuel and air in a mixture at standard temperature and pressure are within the upper and lower flammability limits or explosive limits (UEL and LEL). See Table 2. Both temperature and pressure affect these limits. As the temperature of the mixture increases, the upper limit increases and the lower limit decreases. As the pressure of the mixture decreases below atmospheric pressure, the upper limit decreases and the lower limit increases.

The preparation of this chapter is assigned to TC 6.10, Fuels and Combustion.

Table 1 Combustion Reactions of Common Fuel Constituents

			Stoichiometric Oxygen and Air Requirements				Flue Gas from Stoichiometric Combustion with Air					
			lb/lb Fuel[a]		ft^3/ft^3 Fuel		Ultimate CO_2, %	Dew Point,[c] °F	ft^3/ft^3 Fuel		lb/lb Fuel	
Constituent	**Molecular Formula**	**Combustion Reactions**	O_2	Air	O_2	Air			CO_2	H_2O	CO_2	H_2O
Carbon (to CO)	C	$C + 0.5O_2 \rightarrow CO$	1.33	5.75	b	b	—	—	—	—	—	—
Carbon (to CO_2)	C	$C + O_2 \rightarrow CO_2$	2.66	11.51	b	b	29.30	—	—	—	3.664	—
Carbon monoxide	CO	$CO + 0.5O_2 \rightarrow CO$	0.57	2.47	0.50	2.39	34.70	—	1.0	—	1.571	—
Hydrogen	H_2	$H_2 + 0.5O_2 \rightarrow H_2O$	7.94	34.28	0.50	2.39	—	162	—	1.0	—	8.937
Methane	CH_4	$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$	3.99	17.24	2.00	9.57	11.73	139	1.0	2.0	2.744	2.246
Ethane	C_2H_6	$C_2H_6 + 3.5O_2 \rightarrow 2CO_2 + 3H_2O$	3.72	16.09	3.50	16.75	13.18	134	2.0	3.0	2.927	1.798
Propane	C_3H_8	$C_3H_8 + 5O_2 \rightarrow 3CO_2 + 4H_2O$	3.63	15.68	5.00	23.95	13.75	131	3.0	4.0	2.994	1.634
Butane	C_4H_{10}	$C_4H_{10} + 6.5O_2 \rightarrow 4CO_2 + 5H_2O$	3.58	15.47	6.50	31.14	14.05	129	4.0	5.0	3.029	1.550
Alkanes	C_nH_{2n+2}	$C_nH_{2n+2} + (1.5n + 0.5)O_2 \rightarrow nCO_2 + (n + 1)H_2O$	—	—	$1.5n + 0.5$	$7.18n + 2.39$	—	128 to 127	n	$n + 1$	$\frac{44.01n}{14.026n + 2.016}$	$\frac{18.01(n + 1)}{14.026n + 2.016}$
Ethylene	C_2H_4	$C_2H_4 + 3O_2 \rightarrow 2CO_2 + 2H_2O$	3.42	14.78	3.00	14.38	15.05	125	2.0	2.0	3.138	1.285
Propylene	C_3H_6	$C_3H_6 + 4.5O_2 \rightarrow 3CO_2 + 3H_2O$	3.42	14.78	4.50	21.53	15.05	125	3.0	3.0	3.138	1.285
Alkenes	C_nH_{2n}	$C_nH_{2n} + 1.5nO_2 \rightarrow nCO_2 + nH_2O$	3.42	14.78	$1.50n$	$7.18n$	15.05	125	n	n	3.138	1.285
Acetylene	C_2H_2	$C_2H_2 + 2.5O_2 \rightarrow 2CO_2 + H_2O$	3.07	13.27	2.50	11.96	17.53	103	2.0	1.0	3.834	0.692
Alkynes	C_nH_{2m}	$C_nH_{2m} + (n + 0.5m)O_2 \rightarrow nCO_2 + mH_2O$	—	—	$n + 0.5m$	$4.78n + 2.39m$	—	—	n	m	$\frac{22.005n}{6.005n + 1.008m}$	$\frac{9.008m}{6.005n + 1.008m}$
									SO_x	H_2O	SO_x	H_2O
Sulfur (to SO_2)	S	$S + O_2 \rightarrow SO_2$	1.00	4.31	b	b	—	—	1.0 SO_2	—	1.998 (SO_2)	—
Sulfur (to SO_3)	S	$S + 1.5O_2 \rightarrow SO_3$	1.50	6.47	b	b	—	—	1.0 SO_3	—	2.497 (SO_3)	—
Hydrogen sulfide	H_2S	$H_2S + 1.5O_2 \rightarrow SO_2 + H_2O$	1.41	6.08	1.50	7.18	—	125	1.0 SO_2	1.0	1.880 (SO_2)	0.528

Adapted, in part, from *Gas Engineers Handbook* (1965)

[a] Atomic masses: H = 1.008, C = 12.01, O = 16.00, S = 32.06.

[b] Volume ratios are not given for fuels that do not exist in vapor form at reasonable temperatures or pressure.

[c] Dew point is determined from Figure 2.

Table 2 Flammability Limits and Ignition Temperatures of Common Fuels in Fuel-Air Mixtures

Substance	Molecular Formula	Lower Flammability Limit, %	Upper Flammability Limit, %	Ignition Temperature, °F	References
Carbon (activated coke)	C	—	—	1220	Hartman (1958)
Carbon monoxide	CO	12.5	74	1128	Scott et al. (1948)
Hydrogen	H_2	4.0	75.0	968	Zabetakis (1956)
Methane	CH_4	5.0	15.0	1301	*Gas Engineers Handbook* (1965)
Ethane	C_2H_6	3.0	12.5	968 to 1166	Trinks (1947)
Propane	C_3H_8	2.1	10.1	871	NFPA (1962)
n-Butane	C_4H_{10}	1.86	8.41	761	NFPA (1962)
Ethylene	C_2H_4	2.75	28.6	914	Scott et al. (1948)
Propylene	C_3H_6	2.00	11.1	856	Scott et al. (1948)
Acetylene	C_2H_2	2.50	81	763 to 824	Trinks (1947)
Sulfur	S	—	—	374	Hartman (1958)
Hydrogen sulfide	H_2S	4.3	45.50	558	Scott et al. (1948)

Flammability limits adapted from Coward and Jones (1952). All values corrected to 60°F, 30 in. Hg, dry.

However, as pressure increases above atmospheric pressure, the upper limit increases and the lower limit is relatively constant.

Ignition Temperature

Ignition temperature is the lowest temperature at which heat is generated by combustion faster than heat is lost to the surroundings and combustion becomes self-propagating. See Table 2. The fuel-air mixture will not burn freely and continuously below the ignition temperature unless heat is supplied, but chemical reaction between the fuel and air may occur. Ignition temperature is affected by a large number of factors.

The ignition temperature and flammability limits of a fuel-air mixture, together, are a measure of the potential for ignition (*Gas Engineers Handbook* 1965).

Combustion Modes

Combustion reactions occur in either continuous or pulse flame modes. **Continuous combustion** burns fuel in a sustained manner as long as fuel and air are continuously fed to the combustion zone and the fuel-air mixture is within the flammability limits. Continuous combustion is more common than pulse combustion and is used in most fuel-burning equipment.

Pulse combustion is an acoustically resonant process that burns various fuels in small, discrete fuel-air mixture volumes in a very rapid series of combustions.

The introduction of fuel and air into the pulse combustor is controlled by mechanical or aerodynamic valves. Typical combustors consist of one or more valves, a combustion chamber, an exit pipe, and a control system (ignition means, fuel-metering devices, etc.). Typically, combustors for warm air furnace, hot water boiler, and commercial cooking equipment use mechanical valves. Aerodynamic valves are usually used in higher pressure applications, such as thrust engines. Separate valves for air and fuel, a single valve for premixed air and fuel, or multiple valves of either type can be used. Premix valve systems may require a flame trap at the combustion chamber entrance to prevent flashback.

In a mechanically valved pulse combustor, air and fuel are forced into the combustion chamber through the valves under pressures less than 0.5 psi. An ignition source, such as a spark, ignites the fuel-air mixture, causing a positive pressure buildup in the combustion chamber. The positive pressure causes the valves to close, leaving only the exit pipe of the combustion chamber as a pressure relief opening. The combustion chamber and exit pipe geometry determine the resonant frequency of the combustor.

The pressure wave from the initial combustion travels down the exit pipe at sonic velocity. As this wave exits the combustion chamber, most of the flue gases present in the chamber are carried with it into the exit pipe. Flue gases remaining in the combustion chamber begin to cool immediately. The contraction of the cooling gases and the momentum of gases in the exit pipe create a vacuum inside the chamber that opens the valves and allows more fuel and air into the chamber. While the fresh charge of fuel-air enters the chamber, the pressure wave reaches the end of the exit pipe and is partially reflected from the open end of the pipe. The fresh fuel-air charge is ignited by residual combustion and/or heat. The resulting combustion starts another cycle.

Typical pulse combustors operate at 30 to 100 cycles per second and emit resonant sound, which must be considered in their application. The pulses produce high convective heat transfer rates.

Heating Value

Combustion produces thermal energy or heat. The quantity of heat generated by complete combustion of a unit of specific fuel is constant and is termed the **heating value**, **heat of combustion,** or **caloric value** of that fuel. The heating value of a fuel can be determined by measuring the heat evolved during combustion of a known quantity of the fuel in a calorimeter, or it can be estimated from chemical analysis of the fuel and the heating values of the various chemical elements in the fuel. For information on calculating heating values, see the sections on Characteristics of Fuel Oils and Characteristics of Coals.

Higher heating value, **gross heating value**, or **total heating value** includes the latent heat of vaporization and is determined when water vapor in the fuel combustion products is condensed. Conversely, **lower heating value** or **net heating value** is obtained when the latent heat of vaporization is *not* included. When the heating value of a fuel is specified without designating higher or lower, it generally means the higher heating value in the United States. (Lower heating value is mainly used for internal combustion engine fuels.)

Heating values are usually expressed in Btu/ft^3 for gaseous fuels, Btu/gal for liquid fuels, and Btu/lb for solid fuels. Heating values are always given in relation to a certain reference temperature and pressure, usually 60, 68, or 77°F and 14.696 psia, depending on the particular industry practice. Heating values of several substances in common fuels are listed in Table 3.

With incomplete combustion, not all fuel is completely oxidized, and the heat produced is less than the heating value of the fuel. Therefore, the quantity of heat produced per unit of fuel consumed decreases, implying lower combustion efficiency.

Not all heat produced during combustion can be used effectively. The greatest heat loss is the thermal energy of the increased temperature of hot exhaust gases above the temperature of incoming air and fuel. Other heat losses include radiation and convection heat transfer from the outer walls of combustion equipment to the environment.

Table 3 Heating Values of Substances Occurring in Common Fuels

Substance	Molecular Formula	Higher Heating Values,[a] Btu/lb	Lower Heating Values,[a] Btu/lb	Specific Volume,[b] ft^3/lb
Carbon (to CO)	C	3,950	3,950	—
Carbon (to CO_2)	C	14,093	14,093	—
Carbon monoxide	CO	4,347	4,347	13.5
Hydrogen	H_2	61,095	51,623	188.0
Methane	CH_4	23,875	21,495	23.6
Ethane	C_2H_6	22,323	20,418	12.5
Propane	C_3H_8	21,669	19,937	8.36
Butane	C_4H_{10}	21,321	19,678	6.32
Ethylene	C_2H_4	21,636	20,275	—
Propylene	C_3H_6	21,048	19,687	9.01
Acetylene	C_2H_2	21,502	20,769	14.3
Sulfur (to SO_2)	S	3,980	3,980	—
Sulfur (to SO_3)	S	5,940	5,940	—
Hydrogen sulfide	H_2S	7,097	6,537	11.0

Adapted from *Gas Engineers Handbook* (1965).

[a] All values corrected to 60°F, 30 in. Hg, dry. For gases saturated with water vapor at 60°F, deduct 1.74% of the value to adjust for gas volume displaced by water vapor.

[b] At 32°F and 29.92 in. Hg.

Altitude Compensation

Air at altitudes above sea level is less dense and has less oxygen per unit volume. Therefore, combustion at altitudes above sea level has less available oxygen to burn with the fuel unless compensation is made for the altitude. Combustion occurs, but the amount of excess air is reduced. If excess air is reduced enough by an increase in altitude, combustion is incomplete or ceases.

Altitude compensation is achieved by matching the fuel and air supply rates to attain complete combustion without too much excess air or too much fuel. Fuel and air supply rates can be matched by increasing the air supply rate to the combustion zone or by decreasing the fuel supply rate to the combustion zone. The air supply rate can be increased with a combustion air blower, and the fuel supply rate can be reduced by decreasing the fuel input (derating).

Power burners use combustion air blowers and can increase the air supply rate to compensate for altitude. The combustion zone can be pressurized to attain the same air density in the combustion chamber as that attained at sea level.

Derating can be used as an alternative to power combustion. In the United States, the fuel gas codes generally do not require derating of nonpower burners at altitudes up to 2000 ft. At altitudes above 2000 ft, burners should be derated 4% for each 1000 ft above sea level (NFPA/IAS *National Fuel Gas Code*). Chimney or vent operation also must be considered at high altitudes (see Chapter 30 of the *ASHRAE Handbook—Systems and Equipment*).

FUEL CLASSIFICATION

Generally, hydrocarbon fuels are classified according to physical state (gas, liquid, or solid). Different types of combustion equipment are usually needed to burn fuels in the different physical states. Gaseous fuels can be burned in premix or diffusion burners. Liquid fuel burners must include a means for atomizing or vaporizing fuel into small droplets or a vapor and must provide adequate mixing of fuel and air. Solid fuel combustion equipment must (1) heat fuel to vaporize sufficient volatiles to initiate and sustain combustion, (2) provide residence time to complete combustion, and (3) provide space for ash containment.

Principal fuel applications include space heating and cooling of residential, commercial, industrial, and institutional buildings; service water heating; steam generation; and refrigeration. Major fuels for these applications are natural and liquefied petroleum gases, fuel oils, diesel and gas turbine fuels (for on-site energy applications), and coal.

Fuels of limited use, such as manufactured gases, kerosene, briquettes, wood, and coke, are not discussed here. Fuel choice is based on one or more of the following:

Fuel factors

- Availability, including dependability of supply
- Convenience of use and storage
- Economy
- Cleanliness

Combustion equipment factors

- Operating requirements
- Cost
- Service requirements
- Ease of control

GASEOUS FUELS

Although various gaseous fuels have been used as energy sources in the past, heating and cooling applications are presently limited to natural gas and liquefied petroleum gases.

Types and Properties

Natural gas is a nearly odorless and colorless gas that accumulates in the upper parts of oil and gas wells. Raw natural gas is a mixture of methane (55 to 98%), higher hydrocarbons (primarily ethane), and noncombustible gases. Some constituents, principally water vapor, hydrogen sulfide, helium, and gases for liquefied petroleum gases and gasoline are removed prior to distribution.

Natural gas used as fuel typically contains methane, CH_4 (70 to 96%); ethane, C_2H_6 (1 to 14%); propane, C_3H_8 (0 to 4%); butane, C_4H_{10} (0 to 2%); pentane, C_5H_{12} (0 to 0.5%); hexane, C_6H_{14} (0 to 2%); carbon dioxide, CO_2 (0 to 2%); oxygen, O_2 (0 to 1.2%); and nitrogen, N_2 (0.4 to 17%).

The composition of natural gas depends on its geographical source. Because the gas is drawn from various sources, the composition of gas distributed in a given location can vary slightly, but a fairly constant heating value is usually maintained for control and safety. Local gas utilities are the best sources of current gas composition data for a particular area.

Heating values of natural gases vary from 900 to 1200 Btu/ft^3; the usual range is 1000 to 1050 Btu/ft^3 at sea level. The heating value for a particular gas can be calculated from the composition data and values in Table 3.

For safety purposes, odorants (such as mercaptans) are added to natural gas and LPG to give them noticeable odors.

Liquefied petroleum gases (LPG) consist primarily of propane and butane, and are usually obtained as a byproduct of oil refinery operations or by stripping natural gas. Propane and butane are gaseous under usual atmospheric conditions, but can be liquefied under moderate pressures at normal temperatures.

Commercial propane consists primarily of propane but generally contains about 5 to 10% propylene. It has a heating value of about 21,560 Btu/lb, about 2500 Btu/ft^3 of gas, or about 91,000 Btu/gal of liquid propane. At atmospheric pressure, commercial propane has a boiling point of about −40°F. The low boiling point of propane allows it to be used during winter in the northern United States and in Canada. Tank heaters and vaporizers permit its use in colder climates and where high fuel flow rates are required. Propane is available in cylinders, bottles, tank trucks, or tank cars.

Propane-air mixtures are used in place of natural gas in small communities and by natural gas companies to supplement normal supplies at peak loads. Table 4 lists heating values and specific gravities for various fuel-air ratios.

Table 4 Propane-Air and Butane-Air Gas Mixtures

Heating Value, Btu/ft^3	Propane-Air[a]			Butane-Air[b]		
	% Gas	% Air	Sp Gr	% Gas	% Air	Sp Gr
500	19.8	80.2	1.103	15.3	84.7	1.155
600	23.8	76.2	1.124	18.4	81.6	1.186
700	27.8	72.2	1.144	21.5	78.5	1.216
800	31.7	68.3	1.165	24.5	75.5	1.248
900	35.7	64.3	1.185	27.6	72.4	1.278
1000	39.7	60.3	1.206	30.7	69.3	1.310
1100	43.6	56.4	1.227	33.7	66.3	1.341
1200	47.5	52.5	1.248	36.8	63.2	1.372
1300	51.5	48.5	1.268	39.8	60.2	1.402
1400	55.5	44.5	1.288	42.9	57.1	1.433
1500	59.4	40.6	1.309	46.0	54.0	1.464
1600	63.4	36.6	1.330	49.0	51.0	1.495
1700	67.4	32.6	1.350	52.1	47.9	1.526
1800	71.3	28.7	1.371	55.2	44.8	1.557

Adapted from *Gas Engineers Handbook* (1965).

[a] Values used for calculation: 2522 Btu/ft^3; 1.52 specific gravity.

[b] Values used for calculation: 3261 Btu/ft^3; 2.01 specific gravity.

Commercial butane consists primarily of butane but may contain up to 5% butylene. It has a heating value of about 21,180 Btu/lb, about 3200 Btu/ft^3 of gas, or about 102,000 Btu/gal of liquid butane. At atmospheric pressure, commercial butane has a relatively high boiling point of about 32°F. Therefore, butane cannot be used in cold weather unless the gas temperature is maintained above 32°F or the partial pressure is decreased by dilution with a gas having a lower boiling point. Butane is usually available in bottles, tank trucks, or tank cars, but not in cylinders.

Butane-air mixtures are used in place of natural gas in small communities and by natural gas companies to supplement normal supplies at peak loads. Table 4 lists heating values and specific gravities for various fuel-air ratios.

Commercial propane-butane mixtures with various ratios of propane and butane are available. Their properties generally fall between those of the unmixed fuels.

Manufactured gases are combustible gases produced from coal, coke, oil, liquefied petroleum gases, or natural gas. For more detailed information, see *Gas Engineers Handbook* (1965). These fuels are used primarily for industrial in-plant operations or as specialty fuels (e.g., acetylene for welding).

LIQUID FUELS

Significant liquid fuels include various fuel oils for firing combustion equipment and engine fuels for on-site energy systems. Liquid fuels, with few exceptions, are mixtures of hydrocarbons derived by refining crude petroleum. In addition to hydrocarbons, crude petroleum usually contains small quantities of sulfur, oxygen, nitrogen, vanadium, other trace metals, and impurities such as water and sediment. Refining produces a variety of fuels and other products. Nearly all lighter hydrocarbons are refined into fuels (e.g., liquefied petroleum gases, gasoline, kerosene, jet fuels, diesel fuels, and light heating oils). Heavy hydrocarbons are refined into residual fuel oils and other products (e.g., lubricating oils, waxes, petroleum coke, and asphalt).

Crude petroleums from different oil fields vary in hydrocarbon molecular structure. Crude is paraffin-base (principally chain-structured paraffin hydrocarbons), naphthene- or asphaltic-base (containing relatively large quantities of saturated ring-structural naphthenes), aromatic-base (containing relatively large quantities of unsaturated, ring-structural aromatics), or mixed- or intermediate-base (between paraffin- and naphthene-base crudes). Except for heavy fuel oils, the crude type has little significant effect on resultant products and combustion applications.

Types of Fuel Oils

Fuel oils for heating are broadly classified as **distillate fuel oils** (lighter oils) or **residual fuel oils** (heavier oils). ASTM *Standard* D 396 has specifications for fuel oil properties that subdivide the oils into various grades. Grades No. 1 and 2 are distillate fuel oils. Grades 4, 5 (Light), 5 (Heavy), and 6 are residual fuel oils. Specifications for the grades are based on required characteristics of fuel oils for use in different types of burners.

Grade No. 1 is a light distillate intended for vaporizing-type burners. High volatility is essential to continued evaporation of the fuel oil with minimum residue.

Grade No. 2 is a heavier distillate than No. 1. It is used primarily with pressure-atomizing (gun) burners that spray the oil into a combustion chamber. The atomized oil vapor mixes with air and burns. This grade is used in most domestic burners and many medium-capacity commercial-industrial burners. A dewaxed No. 2 oil with a pour point of −58°F is supplied only to areas where regular No. 2 oil would jell.

Grade No. 4 is an intermediate fuel that is considered either a heavy distillate or a light residual. Intended for burners that atomize oils of higher viscosity than domestic burners can handle, its permissible viscosity range allows it to be pumped and atomized at relatively low storage temperatures.

Grade No. 5 (*Light*) is a residual fuel of intermediate viscosity for burners that handle fuel more viscous than No. 4 without preheating. Preheating may be necessary in some equipment for burning and, in colder climates, for handling.

Grade No. 5 (*Heavy*) is a residual fuel more viscous than No. 5 (Light), but intended for similar purposes. Preheating is usually necessary for burning and, in colder climates, for handling.

Grade No. 6, sometimes referred to as Bunker C, is a high-viscosity oil used mostly in commercial and industrial heating. It requires preheating in the storage tank to permit pumping, and additional preheating at the burner to permit atomizing.

Low-sulfur residual oils are marketed in many areas to permit users to meet sulfur dioxide emission regulations. These fuel oils are produced (1) by refinery processes that remove sulfur from the oil (hydrodesulfurization), (2) by blending high-sulfur residual oils with low-sulfur distillate oils, or (3) by a combination of these methods. These oils have significantly different characteristics from regular residual oils. For example, the viscosity-temperature relationship can be such that low-sulfur fuel oils have viscosities of No. 6 fuel oils when cold, and of No. 4 when heated. Therefore, normal guidelines for fuel handling and burning can be altered when using these fuels.

Fuel oil grade selection for a particular application is usually based on availability and economic factors, including fuel cost, clean air requirements, preheating and handling costs, and equipment cost. Installations with low firing rates and low annual fuel consumption cannot justify the cost of preheating and other methods that use residual fuel oils. Large installations with high annual fuel consumption cannot justify the premium cost of distillate fuel oils.

Characteristics of Fuel Oils

Characteristics that determine grade classification and suitability for given applications are (1) viscosity, (2) flash point, (3) pour point, (4) water and sediment content, (5) carbon residue, (6) ash, (7) distillation qualities or distillation temperature ranges, (8) specific gravity, (9) sulfur content, (10) heating value, and (11) carbon-hydrogen content. Not all of these are included in ASTM *Standard* D 396.

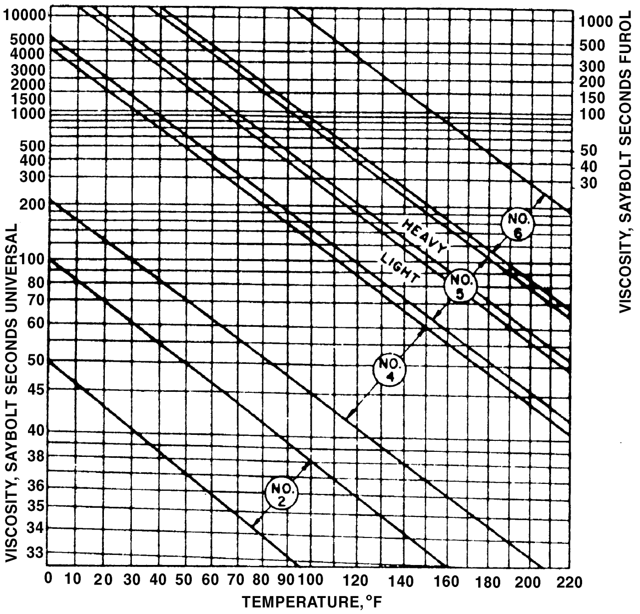


Fig. 1 Approximate Viscosity of Fuel Oils

Viscosity is an oil's resistance to flow. It is significant because it indicates the ease at which oil flows or can be pumped and the ease of atomization. Differences in fuel oil viscosities are caused by variations in the concentrations of fuel oil constituents and different refining methods. Approximate viscosities of fuel oils are shown in Figure 1.

Flash point is the lowest temperature to which an oil must be heated for its vapors to ignite in a flame. Minimum permissible flash point is usually prescribed by state and municipal laws.

Pour point is the lowest temperature at which a fuel can be stored and handled. Fuels with higher pour points can be used when heated storage and piping facilities are provided.

Water and **sediment content** should be low to prevent fouling the facilities. Sediment accumulates on filter screens and burner parts. Water in distillate fuels can cause tanks to corrode and emulsions to form in residual oil.

Carbon residue is obtained by a test in which the oil sample is destructively distilled in the absence of air. When commercial fuels are used in proper burners, this residue has almost no relationship to soot deposits, except indirectly when deposits are formed by vaporizing burners.

Ash is the noncombustible material in an oil. An excessive amount indicates the presence of materials that cause high wear on burner pumps.

The **distillation** test shows the volatility and ease of vaporization of a fuel.

Specific gravity is the ratio of the density of a fuel oil to the density of water at a specific temperature. **Specific gravities** cover a range in each grade, with some overlap between distillate and residual grades. **API gravity** (developed by the American Petroleum Institute) is a parameter widely used in place of specific gravity. It is obtained by the following formula:

$$\text{Degrees API} = \frac{141.5}{\text{Sp Gr at } 60/60°\text{F}} - 131.5 \qquad (1)$$

where Sp Gr at 60/60°F is the ratio of the mass of a given volume of oil at 60°F to the mass of the same volume of water at 60°F.

The API gravity of water at 60°F is 10.0.

Air pollution considerations are important in determining the allowable **sulfur content** of fuel oils. Sulfur content is frequently limited by legislation aimed at reducing sulfur oxide emissions from combustion equipment. These laws require sulfur content to be below a certain level, usually 1.0, 0.5, or 0.3%. Table 5 lists sulfur levels of some marketed fuel oils.

Table 5 Sulfur Content of Marketed Fuel Oils

Grade of Oil	No. 1	No. 2	No. 4	No. 5 (Light)	No. 5 (Heavy)	No. 6
Total fuel samples	31	61	13	15	16	96
Sulfur content,						
% mass minimum	0.001	0.03	0.46	0.90	0.57	0.32
maximum	0.120	0.50	1.44	3.50	2.92	4.00
average	0.023	0.20	0.83	1.46	1.46	1.41
No. samples with S						
over 0.3%	0	17	13	15	16	96
over 0.5%	0	2	11	15	16	93
over 1.0%	0	0	3	9	11	60
over 3.0%	0	0	0	2	0	8

Data for No. 1 and No. 2 oil derived from Dickson and Sturm (1994).
Data for No. 4, 5, and 6 oil derived from Shelton (1974).

Table 6 Typical API Gravity, Density, and Higher Heating Value of Standard Grades of Fuel Oil

Grade No.	API Gravity	Density, lb/gal	Higher Heating Value, Btu/gal
1	38 to 45	6.950 to 6.675	137,000 to 132,900
2	30 to 38	7.296 to 6.960	141,800 to 137,000
4	20 to 28	7.787 to 7.396	148,100 to 143,100
5L	17 to 22	7.940 to 7.686	150,000 to 146,800
5H	14 to 18	8.080 to 7.890	152,000 to 149,400
6	8 to 15	8.448 to 8.053	155,900 to 151,300

Sulfur in fuel oils is also undesirable because of the corrosiveness of sulfur compounds in the flue gas. Although low-temperature corrosion can be minimized by maintaining the stack at temperatures above the dew point of the flue gas, this limits the overall thermal efficiency of combustion equipment.

For certain industrial applications, the sulfur content of a fuel must be limited because of adverse effects on product quality. The applications include direct-fired metallurgy where work is performed in the combustion zone.

Heating value is an important property, although ASTM *Standard* D 396 does not list it as one of the criteria for fuel oil classification. Heating value can generally be correlated with the API gravity. Table 6 shows the relationship between heating value, API gravity, and density for several oil grades. In the absence of more specific data, heating values can be calculated as shown in the *North American Combustion Handbook* (1978):

$$\text{Higher heating value, Btu/lb} = 22{,}320 - 3{,}780(\text{Specific gravity})^2 \tag{2}$$

Distillate fuel oils (Grades 1 and 2) have a carbon-hydrogen content of 84 to 86% carbon, with the remainder predominantly hydrogen. The heavier residual fuel oils (Grades 4, 5, and 6) may contain up to 88% carbon and as little as 11% hydrogen. An approximate relationship for determining the hydrogen content of fuel oils is

$$\text{Hydrogen, \%} = 26 - (15 \times \text{Specific gravity}) \tag{3}$$

ASTM *Standard* D 396 is more a classification than a specification, distinguishing between six generally nonoverlapping grades, one of which characterizes any commercial fuel oil. Quality is not defined, as a refiner might control it; for example, the standard lists the distillation temperature 90% point for Grade No. 2 as having a maximum of 640°F, whereas commercial practice rarely exceeds 600°F.

Types and Properties of Liquid Fuels for Engines

The primary stationary engine fuels are diesel and gas turbine oils, natural gases, and liquefied petroleum gases. Other fuels include sewage gas, manufactured gas, and gas mixtures. Gasoline and the JP series of gas turbine fuels are rarely used for stationary engines.

Only properties of diesel and gas turbine fuel oils are covered here; properties of natural and liquefied petroleum gases are found in the section on Gaseous Fuels. For properties of gasolines and JP turbine fuel, consult texts on internal combustion engines and gas turbines. Properties of currently marketed gasolines can be found in the latest volumes of *Mineral Industry Surveys*, *Motor Gasolines*, issued semiannually by the U.S. Bureau of Mines.

Properties of the three grades of diesel fuel oils (1-D, 2-D, and 4-D) are listed in ASTM *Standard* D 975.

Grade No. 1-D includes the class of volatile fuel oils from kerosene to intermediate distillates. These fuels are used in high-speed engines with frequent and relatively wide variations in loads and speeds and where abnormally low fuel temperatures are encountered.

Grade No. 2-D includes the class of lower volatility distillate gas oils. These fuels are used in high-speed engines with relatively high loads and uniform speeds, or in engines not requiring fuels with the higher volatility or other properties specified for Grade No. 1-D.

Grade No. 4-D covers the class of more viscous distillates and blends of these distillates with residual fuel oils. These fuels are used in low- and medium-speed engines involving sustained loads at essentially constant speed.

Property specifications and test methods for Grade No. 1-D, 2-D, and 4-D diesel fuel oils are essentially identical to specifications of Grade No. 1, 2, and 4 fuel oils, respectively. However, diesel fuel oils have an additional specification for **cetane number**, which measures ignition quality and influences combustion roughness. Cetane number requirements depend on engine design, size, speed and load variations, and starting and atmospheric conditions. An increase in cetane number over values actually required does not improve engine performance. Thus, the cetane number should be as low as possible to assure maximum fuel availability. ASTM *Standard* D 975 provides several methods for estimating cetane number from other fuel oil properties.

ASTM *Standard* D 2880 for gas turbine fuel oils relates gas turbine fuel oil grades to fuel and diesel fuel oil grades. Test methods for determining properties of gas turbine fuel oils are essentially identical to those for fuel oils. However, gas turbine specifications contain quantity limits on some trace elements that may be present. These limits are intended to prevent excessive corrosion in gas turbine engines. For a detailed discussion of fuels for gas turbines and combustion in gas turbines, see Chapters 5 and 9, respectively, in Hazard (1971).

SOLID FUELS

Solid fuels include coal, coke, wood, and waste products of industrial and agricultural operations. Of these, only coal is widely used for heating and cooling applications.

The complex composition of coal makes classification difficult. Chemically, coal consists of carbon, hydrogen, oxygen, nitrogen, sulfur, and a mineral residue, ash. Chemical analysis provides some indication of coal quality, but does not define its burning characteristics sufficiently. The coal user is principally interested in the available heat per unit mass of coal and the amount of ash and dust produced, but is also interested in burning characteristics and handling and storing properties. A description of coal qualities and their characteristics can be obtained from the U.S. Bureau of Mines.

Table 7 Classification of Coals by Rank[a]

	Class		Group	Limits of Fixed Carbon or Energy Content, Mineral-Matter-Free Basis	Requisite Physical Properties
I	Anthracite	1.	Metaanthracite	Dry FC, 98% or more (Dry VM, 2% or less)	Nonagglomerating
		2.	Anthracite	Dry FC, 92% or more, and less than 98% (Dry VM, 8% or less, and more than 2%)	
		3.	Semianthracite	Dry FC, 86% or more, and less than 92% (Dry VM, 14% or less, and more than 8%)	
II	Bituminous[d]	1.	Low-volatile bituminous coal	Dry FC, 78% or more, and less than 86% (Dry VM, 22% or less, and more than 14%)	Either agglomerating[b] or nonweathering[f]
		2.	Medium-volatile bituminous coal	Dry FC, 69% or more, and less than 78% (Dry VM, 31% or less, and more than 22%)	
		3.	High-volatile *A* bituminous coal	Dry FC, less than 69% (Dry VM, more than 31%), and moist[c], about 14,000 Btu/lb[e] or more	
		4.	High-volatile *B* bituminous coal	Moist[c], about 13,000 Btu/lb or more, and less than 14,000 Btu/lb[e]	
		5.	High-volatile *C* bituminous coal	Moist[c], about 11,000 Btu/lb or more, and less than 13,000 Btu/lb[e]	
III	Subbituminous	1.	Subbituminous *A* coal	Moist[c], about 11,000 Btu/lb or more, and less than 13,000 Btu/lb[e]	Both weathering and nonagglomerating[b]
		2.	Subbituminous *B* coal	Moist[c], about 9,500 Btu/lb or more, and less than 11,000 Btu/lb[e]	
		3.	Subbituminous *C* coal	Moist[c], about 8,300 Btu/lb or more, and less than 9,500 Btu/lb[e]	
IV	Lignitic	1.	Lignite	Moist[c], less than 8,300 Btu/lb	Consolidated
		2.	Brown coal	Moist[c], less than 8,300 Btu/lb	Unconsolidated

Source: Adapted from ASTM *Standard* D 388, Standard Classification of Coals by Rank.

FC = Fixed Carbon; VM = Volatile Matter.

[a] This classification does not include a few coals of unusual physical and chemical properties which come within the limits of fixed carbon or Btu of high-volatile bituminous and subbituminous ranks. All these coals either contain less than 48% dry, mineral-matter-free fixed carbon, or have more than about 15,500 Btu/lb, which is moist, mineral-matter-free.

[b] If agglomerating, classify in low-volatile group of the bituminous class.

[c] Moist refers to coal containing its natural bed moisture but not including visible water on the coal surface.

[d] There may be noncaking varieties in each group of the bituminous class.

[e] Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of energy content.

[f] There are three varieties of coal in the high-volatile *C* bituminous coal group: Variety 1, agglomerating and nonweathering; Variety 2, agglomerating and weathering; and Variety 3, nonagglomerating and nonweathering.

Types of Coals

Commonly accepted definitions for classifying coals are listed in Table 7. This classification is arbitrary because there are no distinct demarcation lines between coal types.

Anthracite is a clean, dense, hard coal that creates little dust in handling. It is comparatively hard to ignite, but burns freely once started. It is noncaking and burns uniformly and smokelessly with a short flame.

Semianthracite has a higher volatile content than anthracite. It is not as hard and ignites more easily. Otherwise, its properties are similar to those of anthracite.

Bituminous coal includes many types of coal with distinctly different compositions, properties, and burning characteristics. Coals range from high-grade bituminous, such as those found in the eastern United States, to low-rank coals, such as those found in the western United States. Caking properties range from coals that melt or become fully plastic, to those from which volatiles and tars are distilled without changing form (classed as noncaking or free-burning). Most bituminous coals are strong and nonfriable enough to permit screened sizes to be delivered free of fines. Generally, they ignite easily and burn freely. Flame length is long and varies with different coals. If improperly fired, much smoke and soot are possible, especially at low burning rates.

Semibituminous coal is soft and friable, and handling creates fines and dust. It ignites slowly and burns with a medium-length flame. Its caking properties increase as volatile matter increases, but the coke formed is weak. With only half the volatile matter content of bituminous coals, burning produces less smoke; hence, it is sometimes called smokeless coal.

Subbituminous coal, such as that found in the western United States, is high in moisture when mined and tends to break up as it dries or is exposed to the weather; it is likely to ignite spontaneously when piled or stored. It ignites easily and quickly, has a medium-length flame, and is noncaking and free-burning. The lumps tend to break into small pieces if poked. Very little smoke and soot are formed.

Lignite is woody in structure, very high in moisture when mined, of low heating value, and clean to handle. It has a greater tendency than subbituminous coals to disintegrate as it dries and is also more likely to ignite spontaneously. Because of its high moisture, freshly mined lignite ignites slowly and is noncaking. The char left after moisture and volatile matter are driven off burns very easily, like charcoal. The lumps tend to break up in the fuel bed and pieces of char that fall into the ash pit continue to burn. Very little smoke or soot forms.

Characteristics of Coal

The characteristics of coals that determine classification and suitability for given applications are the proportions of (1) volatile matter, (2) fixed carbon, (3) moisture, (4) sulfur, and (5) ash. Each of these is reported in the proximate analysis. Coal analyses can be reported on several bases: as-received, moisture-free (or dry), and mineral-matter-free (or ash-free). As-received is applicable for combustion calculations; moisture-free and mineral-matter-free, for classification purposes.

Volatile matter is driven off as gas or vapor when the coal is heated according to a standard temperature test. It consists of a variety of organic gases, generally resulting from distillation and decomposition. Volatile products given off by coals when heated differ materially in the ratios (by mass) of the gases to oils and tars. No heavy oils or tars are given off by anthracite, and very small quantities are given off by semianthracite. As volatile matter in the coal increases to as much as 40% of the coal (dry and ash-free basis), increasing amounts of oils and tars are released. However, for coals of higher volatile content, the quantity of oils and tars decreases and is relatively low in the subbituminous coals and in lignite.

Table 8 Typical Ultimate Analyses for Coals

Rank	As Received, Btu/lb	Constituents, Percent by Mass					
		Oxygen	Hydrogen	Carbon	Nitrogen	Sulfur	Ash
Anthracite	12,700	5.0	2.9	80.0	0.9	0.7	10.5
Semianthracite	13,600	5.0	3.9	80.4	1.1	1.1	8.5
Low-volatile bituminous	14,350	5.0	4.7	81.7	1.4	1.2	6.0
Medium-volatile bituminous	14,000	5.0	5.0	81.4	1.4	1.5	6.0
High-volatile bituminous *A*	13,800	9.3	5.3	75.9	1.5	1.5	6.5
High-volatile bituminous *B*	12,500	13.8	5.5	67.8	1.4	3.0	8.5
High-volatile bituminous *C*	11,000	20.6	5.8	59.6	1.1	3.5	9.4
Subbituminous *B*	9,000	29.5	6.2	52.5	1.0	1.0	9.8
Subbituminous *C*	8,500	35.7	6.5	46.4	0.8	1.0	9.6
Lignite	6,900	44.0	6.9	40.1	0.7	1.0	7.3

Fixed carbon is the combustible residue left after the volatile matter is driven off. It is not all carbon. Its form and hardness are an indication of fuel coking properties and, therefore, guide the choice of combustion equipment. Generally, fixed carbon represents that portion of fuel that must be burned in the solid state.

Moisture is difficult to determine accurately because a sample can lose moisture on exposure to the atmosphere, particularly when reducing the sample size for analysis. To correct for this loss, total moisture content of a sample is customarily determined by adding the moisture loss obtained when air-drying the sample to the measured moisture content of the dried sample. Moisture does not represent all of the water present in coal; water of decomposition (combined water) and of hydration are not given off under standardized test conditions.

Ash is the noncombustible residue remaining after complete coal combustion. Generally, the mass of ash is slightly less than that of mineral matter before burning.

Sulfur is an undesirable constituent in coal, because the sulfur oxides formed when it burns contribute to air pollution and cause combustion system corrosion. Table 8 lists the sulfur content of typical coals. Legislation has limited the sulfur content of coals burned in certain locations.

Heating value may be reported on an as-received, dry, dry and mineral-matter-free, or moist and mineral-matter-free basis. Higher heating values of coals are frequently reported with their proximate analysis. When more specific data are lacking, the higher heating value of higher quality coals can be calculated by the Dulong formula:

$$\text{Higher heating value, Btu/lb} = 14{,}544C + 62{,}028[H - (O/8)] + 4{,}050S \qquad (4)$$

where C, H, O, and S are the mass fractions of carbon, hydrogen, oxygen, and sulfur in the coal.

Other important parameters in judging coal suitability include

1. **Ultimate analysis**, which is another method of reporting coal composition. Percentages of C, H, O, N, S, and ash in the coal sample are reported. Ultimate analysis is used for detailed fuel studies and for computing a heat balance when required in heating device testing. Typical ultimate analyses of various coals are shown in Table 8.
2. **Ash-fusion temperature**, which indicates the fluidity of the ash at elevated temperatures. It is helpful in selecting coal to be burned in a particular furnace and in estimating the possibility of ash handling and slagging problems.
3. The **grindability index**, which indicates the ease with which a coal can be pulverized and is helpful in estimating ball mill capacity with various coals. There are two common methods for determining the index—Hardgrove and ball mill.
4. The **free-swelling index**, which denotes the extent of coal swelling on combustion on a fuel bed and indicates the coking characteristics of coal.

COMBUSTION CALCULATIONS

Calculations of the quantity of air required for combustion and the quantity of flue gas products generated during combustion are frequently needed for sizing system components and as input to efficiency calculations. Other calculations, such as values for excess air and theoretical CO_2, are useful in estimating combustion system performance.

Frequently, combustion calculations can be simplified by using molecular mass. The molecular mass of a compound equals the sum of the atomic masses of the elements in the compound. Molecular mass can be expressed in any mass units. The pound molecular weight or pound mole is the molecular weight of the compound expressed in pounds. The molecular mass of any substance contains the same number of molecules as the molecular mass of any other substance.

Corresponding to measurement standards common to the industries, calculations involving gaseous fuels are generally based on volume, and calculations involving liquid and solid fuels are generally based on mass.

Some calculations described here require data on concentrations of carbon dioxide, carbon monoxide, and oxygen in the flue gas. Gas analyses for CO_2, CO, and O_2 can be obtained by volumetric chemical analysis and other analytical techniques, including electromechanical cells used in portable electronic flue gas analyzers.

Air Required for Combustion

Stoichiometric or theoretical air is the exact quantity of air required to provide oxygen for complete combustion.

The three most prevalent components in hydrocarbon fuels (C, H_2, and S) are completely combusted as in the following reactions:

$$C + O_2 \rightarrow CO_2$$

$$H_2 + 0.5O_2 \rightarrow H_2O$$

$$S + O_2 \rightarrow SO_2$$

In the reactions, C, H_2, and S can be taken to represent 1 lb mole of carbon, hydrogen, and sulfur, respectively. Using approximate atomic masses (C = 12, H = 1, S = 32, and O = 16), 12 lb of C are oxidized by 32 lb of O_2 to form 44 lb of CO_2, 2 lb of H_2 are oxidized by 16 lb of O_2 to form 18 lb of H_2O, and 32 lb of S are oxidized by 32 lb of O_2 to form 64 lb of SO_2. These relationships can be extended to include hydrocarbons.

The mass of dry air required to supply a given quantity of oxygen is 4.32 times the mass of the oxygen. The mass of air required to oxidize the fuel constituents listed in Table 1 was calculated on this basis. Oxygen contained in the fuel, except that contained in ash, should be deducted from the amount of oxygen required, because this oxygen is already combined with fuel components. In addition, when calculating the mass of air to be supplied for combustion, allowance should be made for water vapor, which is always present in atmospheric air.

As stated previously, combustion calculations for gaseous fuels are based on volume. Avogadro's law states that, for any gas, one mole occupies the same volume at a given temperature and pressure. Therefore, in reactions involving gaseous compounds, the gases react in volume ratios identical to the pound mole ratios. That is, for the oxidation of hydrogen in the above reaction, one volume (or one lb mole) of hydrogen reacts with one-half volume (or one-half lb mole) of oxygen to form one volume (or one lb mole) of water vapor.

The volume of air required to supply a given volume of oxygen is 4.78 times the volume of oxygen. The volumes of dry air required to oxidize the fuel constituents listed in Table 1 were calculated on this basis. Volume ratios are not given for fuels that do not exist in vapor form at reasonable temperatures or pressures. Again, oxygen contained in the fuel should be deducted from the quantity of oxygen required, because this oxygen is already combined with fuel components. Allowance should be made for water vapor, which increases the volume of dry air by 1 to 3%.

From the relationships just described, the theoretical mass m_a of dry air required for stoichiometric combustion of a unit mass of any hydrocarbon fuel is

$$m_a = 0.0144(8\mathrm{C} + 24\mathrm{H} + 3\mathrm{S} - 3\mathrm{O}) \tag{5}$$

where C, H, S, and O are the mass percentages of carbon, hydrogen, sulfur, and oxygen in the fuel.

Analyses of gaseous fuels are generally based on hydrocarbon components rather than elemental content.

If the fuel analysis is based on mass, the theoretical mass m_a of dry air required for stoichiometric combustion of a unit mass of gaseous fuel is

$$\begin{aligned} m_a = {} & 2.47\mathrm{CO} + 34.28\mathrm{H_2} + 17.24\mathrm{CH_4} + 16.09\mathrm{C_2H_6} \\ & + 15.68\mathrm{C_3H_8} + 15.47\mathrm{C_4H_{10}} + 13.27\mathrm{C_2H_2} \\ & + 14.78\mathrm{C_2H_4} + 6.08\mathrm{H_2S} - 4.32\mathrm{O_2} \end{aligned} \tag{6}$$

If the fuel analysis is reported on a volumetric or molecular basis, it is simplest to calculate air requirements based on volume and, if necessary, convert to mass. The theoretical volume V_a of air required for stoichiometric combustion of a unit volume of gaseous fuels is

$$\begin{aligned} V_a = {} & 2.39\mathrm{CO} + 2.39\mathrm{H_2} + 9.57\mathrm{CH_4} + 16.75\mathrm{C_2H_6} \\ & + 23.95\mathrm{C_3H_8} + 31.14\mathrm{C_4H_{10}} + 11.96\mathrm{C_2H_2} \\ & + 14.38\mathrm{C_2H_4} + 7.18\mathrm{H_2S} - 4.78\mathrm{O_2} \\ & + 30.47\ \text{illuminants} \end{aligned} \tag{7}$$

where CO, H_2, and so forth are the volumetric fractions of each constituent in the fuel gas.

Illuminants include a variety of compounds not separated by usual gas analysis. In addition to ethylene (C_2H_4) and acetylene (C_2H_2), the principal illuminants included in Equation (7), and the dry air required for combustion, per unit volume of each gas, are: propylene (C_3H_6), 21.44; butylene (C_4H_8), 28.58; pentene (C_5H_{10}), 35.73; benzene (C_6H_6); 35.73, toluene (C_7H_8), 42.88; and xylene (C_8H_{10}), 50.02. Because toluene and xylene are normally scrubbed from the gas before distribution, they can be disregarded in computing air required for combustion of gaseous fuels. The percentage of illuminants present in gaseous fuels is small, so the values can be lumped together, and an approximate value of 30 unit volumes of dry air per unit volume of gas can be used. If ethylene and acetylene are included as illuminants, a value of 20 unit volumes of dry air per unit volume of gaseous illuminants can be used.

For many combustion calculations, only approximate values of air requirements are necessary. If approximate values for theoretical air are sufficient, or if complete information on the fuel is not available, the values in Tables 9 and 10 can be used. Another value used for estimating air requirements is 0.9 ft^3 of air for 100 Btu of fuel.

Table 9 Approximate Air Requirements for Stoichiometric Combustion of Fuels

Type of Fuel	Air Required		Approx. Precision, %	Exceptions
	lb/lb Fuel	ft^3/Unit Fuel[a]		
Solid	Btu/lb × 0.00073	Btu/lb × 0.0097	3	Fuels containing more than 30% water
Liquid	Btu/lb × 0.00071	Btu/lb × 0.0094	3	Results low for gasoline and kerosene
Gas	Btu/lb × 0.00067	Btu/ft^3 × 0.0089	5	300 Btu/ft^3 or less

Source: Data based on Shnidman (1954).

[a] Unit fuel for solid and liquid fuels in lb, for gas in ft^3.

Table 10 Approximate Air Requirements for Stoichiometric Combustion of Various Fuels

Type of Fuel	Theoretical Air Required for Combustion
Solid fuels	lb/lb fuel
Anthracite	9.6
Semibituminous	11.2
Bituminous	10.3
Lignite	6.2
Coke	11.2
Liquid fuels	lb/gal fuel
No. 1 fuel oil	103
No. 2 fuel oil	106
No. 5 fuel oil	112
No. 6 fuel oil	114
Gaseous fuels	ft^3/ft^3 fuel
Natural gas	9.6
Butane	31.1
Propane	24.0

In addition to the amount theoretically required for combustion, **excess air** must be supplied to most practical combustion systems to ensure complete combustion.

$$\text{Excess air, \%} = \frac{\text{Air supplied} - \text{Theoretical air}}{\text{Theoretical air}} \tag{8}$$

The excess air level at which a combustion process operates significantly affects its overall efficiency. Too much excess air dilutes flue gas excessively, lowering its heat transfer temperature and increasing sensible flue gas loss. Conversely, if the level of excess air is too low, incomplete combustion and loss of unburned combustible gases from the equipment can result. The highest combustion efficiency is usually obtained when just enough excess air is supplied and properly mixed with combustible gases to ensure complete combustion. The general practice is to supply from 5 to 50% excess air, the exact amount depending on the type of fuel burned, combustion equipment, and other factors.

The amount of dry air supplied per unit mass of fuel burned can be obtained from the following equation, which is reasonably precise for most solid and liquid fuels.

$$\text{Dry air supplied} = \frac{\mathrm{C}\ (3.04\mathrm{N_2})}{\mathrm{CO_2} + \mathrm{CO}} \tag{9}$$

where

Dry air supplied = unit mass per unit mass of fuel

C = unit mass of carbon burned per unit mass of fuel, corrected for carbon in the ash

CO_2, CO, N_2 = percentages by volume from the flue gas analysis

These values of dry air supplied and theoretical air can be used in Equation (8) to determine excess air.

Excess air can also be calculated from unit volumes of stoichiometric combustion products and air, and from volumetric analysis of the flue gas:

$$\text{Excess air, \%} = 100\left(\frac{P}{A}\right)\left(\frac{U - CO_2}{CO_2}\right) \qquad (10)$$

where

U = ultimate carbon dioxide of flue gases resulting from stoichiometric combustion, %

CO_2 = carbon dioxide content of flue gases, %

P = dry products from stoichiometric combustion, unit volume per unit volume of gas burned

A = air required for stoichiometric combustion, unit volume per unit volume of gas burned

As the ratio P/A is approximately 0.9 for most natural gases, a value of 90 can be substituted for 100 (P/A) in Equation (10) for rough calculation.

Because excess air calculations are almost invariably made from flue gas analysis results and theoretical air requirements are not always known, another convenient method of expressing the relation of Equation (8) is

$$\text{Excess air, \%} = \frac{100[O_2 - (CO/2)]}{0.264N_2 - [O_2 - (CO/2)]} \qquad (11)$$

where O_2, CO, and N_2 are percentages by volume from the flue gas analysis.

Theoretical CO_2

The theoretical CO_2, ultimate CO_2, stoichiometric CO_2, or maximum CO_2 concentration attainable in the products from the combustion of a hydrocarbon fuel with air is obtained when the fuel is completely burned with the theoretical quantity of air and zero excess air. Theoretical CO_2 varies with the carbon-hydrogen ratio of the fuel. For combustion with excess air present, theoretical CO_2 values can be calculated from the flue gas analysis:

$$\text{Theoretical } CO_2\text{, \%} = U = \frac{CO_2}{1 - (O_2/20.95)} \qquad (12)$$

where CO_2 and O_2 are percentages by volume from the flue gas analysis.

Table 11 gives approximate theoretical CO_2 values for stoichiometric combustion of several common types of fuel, as well as CO_2 values attained with different amounts of excess air. In practice, desirable CO_2 values depend on the excess air, fuel, firing method, and other considerations.

Quantity of Flue Gas Produced

The mass of dry flue gas produced per mass of fuel burned is required in heat loss and efficiency calculations. This mass is equal to the sum of the mass of (1) fuel (minus ash retained in the furnace), (2) air theoretically required for combustion, and (3) excess air. For solid fuels, this mass, determined from the flue gas analysis, is

$$\text{Dry flue gas} = \frac{11CO_2 + 8O_2 + 7(CO + N_2)}{3(CO_2 + CO)}\,C \qquad (13)$$

where

Dry flue gas = lb/lb of fuel

C = lb of carbon burned per lb of fuel, corrected for carbon in the ash

CO_2, O_2, CO, N_2 = percentages by volume from flue gas analysis

Table 11 Approximate Maximum Theoretical (Stoichiometric) CO_2 Values, and CO_2 Values of Various Fuels with Different Percentages of Excess Air

Type of Fuel	Theoretical or Maximum CO_2, %	Percent CO_2 at Given Excess Air Values 20%	40%	60%
Gaseous Fuels				
Natural gas	12.1	9.9	8.4	7.3
Propane gas (commercial)	13.9	11.4	9.6	8.4
Butane gas (commercial)	14.1	11.6	9.8	8.5
Mixed gas (natural and carbureted water gas)	11.2	12.5	10.5	9.1
Carbureted water gas	17.2	14.2	12.1	10.6
Coke oven gas	11.2	9.2	7.8	6.8
Liquid Fuels				
No. 1 and 2 fuel oil	15.0	12.3	10.5	9.1
No. 6 fuel oil	16.5	13.6	11.6	10.1
Solid Fuels				
Bituminous coal	18.2	15.1	12.9	11.3
Anthracite	20.2	16.8	14.4	12.6
Coke	21.0	17.5	15.0	13.0

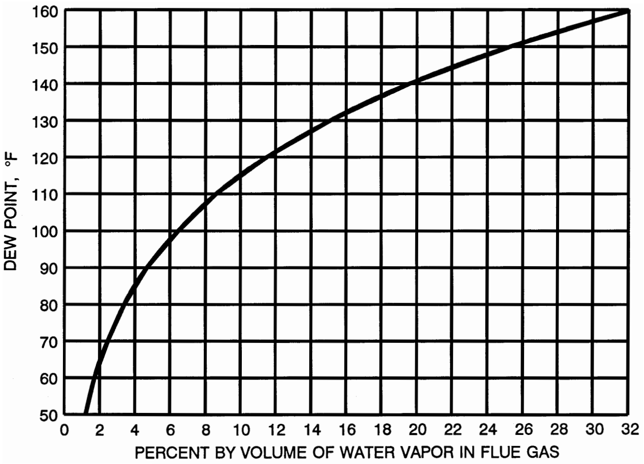


Fig. 2 Water Vapor and Dew Point of Flue Gas

Adapted from *Gas Engineers Handbook* (1965). Printed with permission of Industrial Press and American Gas Association.

The total dry gas volume of flue gases from combustion of one unit volume of gaseous fuels for various percentages of CO_2 is

$$\text{Dry flue gas} = \left(\frac{\text{Volume of } CO_2 \text{ produced}}{\text{Unit vol. of gas burned}}\right)\left(\frac{100}{CO_2}\right) \qquad (14)$$

where

Dry flue gas = unit volume per unit volume of gaseous fuel

CO_2 = percentage by volume from the flue gas analysis

Excess air quantity can be estimated by subtracting the quantity of dry flue gases resulting from stoichiometric combustion from the total volume of flue gas.

Water Vapor and Dew Point of Flue Gas

Water vapor in flue gas is the total of (1) the water contained in the fuel; (2) the water contained in the stoichiometric and excess air; and (3) the water produced from the combustion of hydrogen or hydrocarbons in the fuel. The amount of water vapor in the stoichiometric combustion products may be calculated from the fuel burned by using the water data in Table 1.

The dew point is the temperature at which condensation begins and can be determined using Figure 2. The volume fraction of water vapor in the flue gas can be determined as follows:

$$P_{wv} = \frac{V_w}{(100\,V_c/P_c) + V_w} \qquad (15)$$

where

V_w = total water vapor volume (from fuel; from stoichiometric, excess, and dilution air; and from combustion)
V_c = unit volume of CO_2 produced per unit volume of gaseous fuel
P_c = percent CO_2 in flue gas

Using Figure 3, the dew points of solid, liquid, or gaseous fuels may be estimated. For example, to find the dew point of flue gas resulting from the combustion of a solid fuel with a weight ratio (hydrogen to carbon-plus-sulfur) of 0.088 and sufficient excess air to produce 11.4% oxygen in the flue gas, start with the weight ratio of 0.088. Proceed vertically to the intersection of the solid fuels curve and then to the theoretical dew point of 115°F on the dew-point scale (see dotted lines in Figure 3). Follow the curve fixed by this point (down and to the right) to 11.4% oxygen in the flue gas (on the abscissa). The actual dew point is 93°F and is found on the dew-point scale.

An estimation can be made of the dew point of the flue gas from natural gas having a higher heating value (HHV) of 1020 Btu/ft^3 with 6.3% oxygen or 31.5% air. Start with 1020 Btu/ft^3 and proceed vertically to the intersection of the gaseous fuels curve and then to the theoretical dew point of 139°F on the dew-point scale. Follow the curve fixed by this point to 6.3% oxygen or 31.5% air in the flue gas. The actual dew point is 127°F.

The presence of sulfur dioxide, and particularly sulfur trioxide, influences the vapor pressure of condensate in flue gas, and the dew point can be raised by as much as 25 to 75°F, as shown in Figure 4. To illustrate the use of Figure 4, for a manufactured gas with a HHV of 550 Btu/ft^3 containing 15 grains of sulfur per 100 ft^3 being burned with 40% excess air, the proper curve in Figure 4 is determined as follows:

$$\frac{\text{Grains of S per 100 ft}^3\text{ of fuel}}{\text{Btu per ft}^3\text{ of fuel}} \times 100 = \frac{15}{550} \times 100 = 2.73 \qquad (16)$$

This curve lies between the 0 and 3 curves and is close to the 3 curve. The dew point for any percentage of excess air from zero to 100% can be determined on this curve. For this flue gas with 40% excess air, the dew point is about 160°F, instead of 127°F for zero sulfur at 40% excess air.

Sample Combustion Calculations

Example 1. Analysis of flue gases from the burning of a natural gas shows 10.0% CO_2, 3.1% O_2, and 86.9% N_2 by volume. Analysis of the fuel is 90% CH_4, 5% N_2, and 5% C_2H_6 by volume. Find U (maximum theoretical percent CO_2), and the percentage of excess air.

Solution: From Equation (12),

$$U = \frac{10.0}{1 - (3.1/20.95)} = 11.74\%\ CO_2$$

From Equation (10), using 100 (P/A) = 90,

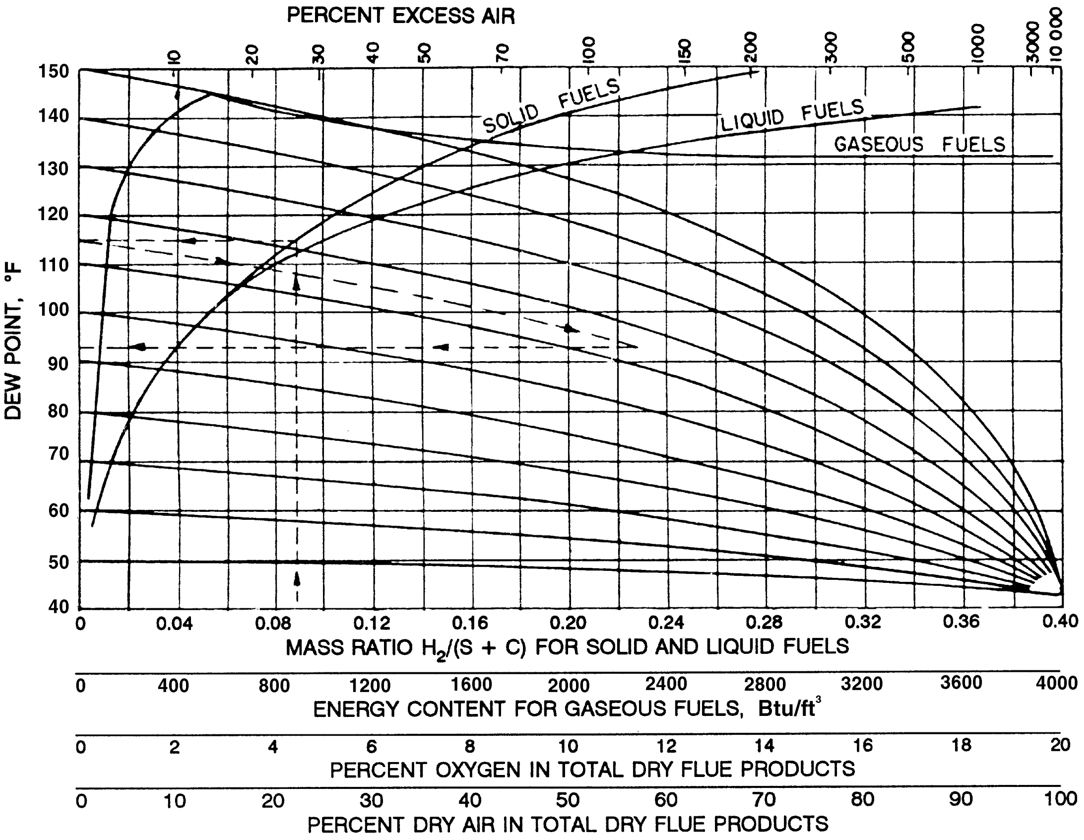


Fig. 3 Theoretical Dew Points of Combustion Products of Industrial Fuels

Adapted from *Gas Engineers Handbook* (1965). Printed with permission of Industrial Press and American Gas Association.

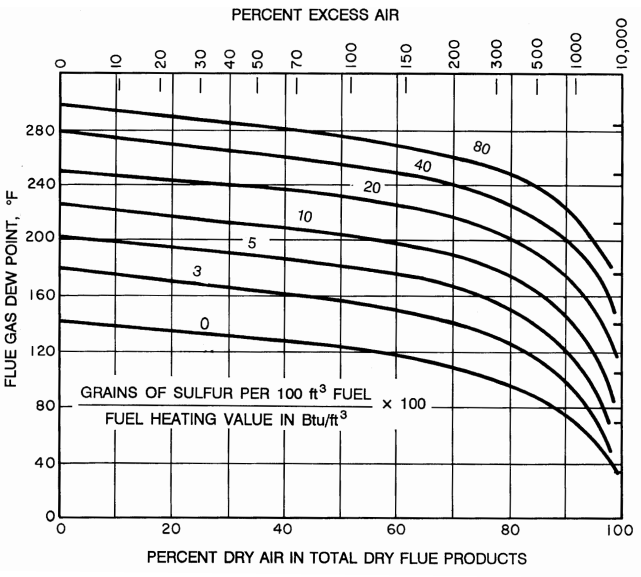


Fig. 4 Influence of Sulfur Oxides on Flue Gas Dew Point
(Stone 1969)

$$\text{Excess air} = \frac{(11.74 - 10.0)90}{10} = 15.7\%$$

Example 2. For the same analysis as in Example 1, find, per cubic foot of fuel gas, the volume of dry air required for combustion, the volume of each constituent in the flue gases, and the total volume of dry and wet flue gases.

Solution: From Equation (7), the volume of dry air required for combustion is:

$$\begin{aligned} 9.57\mathrm{CH_4} + 16.75\mathrm{C_2H_6} &= (9.57 \times 0.90) + (16.75 \times 0.05) \\ &= 9.45\ \mathrm{ft^3}\ \text{per}\ \mathrm{ft^3}\ \text{of fuel gas} \end{aligned}$$

(The volume of dry air may also be calculated using Table 10.)

From Table 1, the cubic feet of flue gas constituents per cubic foot of fuel gas are as follows:

Nitrogen, N_2		
From methane	$(0.9\mathrm{CH_4})(9.57 - 2.0)$	= 6.81
From ethane	$(0.05\mathrm{C_2H_6})(16.75 - 3.5)$	= 0.66
Nitrogen in fuel		= 0.05
Nitrogen in excess air	$0.791 \times 0.157 \times 9.45$	= 1.17
	Total nitrogen	= 8.69 $\mathrm{ft^3}$
Oxygen, O_2		
In excess air	$0.209 \times 0.157 \times 9.45$	= 0.31 $\mathrm{ft^3}$
Carbon dioxide, CO_2		
From methane	$(0.9\mathrm{CH_4})(1.0)$	= 0.90
From ethane	$(0.05\mathrm{C_2H_6})(2.0)$	= 0.10
	Total carbon dioxide	= 1.00 $\mathrm{ft^3}$
Water vapor, H_2O (does not appear in some flue gas analyses)		
From methane	$(0.9\mathrm{CH_4})(2.0)$	= 1.8
From ethane	$(0.05\mathrm{C_2H_6})(3.0)$	= 0.15
	Total water vapor	= 1.95 $\mathrm{ft^3}$

Total volume of dry gas per cubic foot of fuel gas

$$8.69 + 0.31 + 1.00 = 10.0\ \mathrm{ft^3}$$

Total volume of wet gases per cubic foot of fuel gas (neglecting water vapor in combustion air)

$$10.0 + 1.95 = 11.95\ \mathrm{ft^3}$$

The cubic feet of dry flue gas per cubic foot of fuel gas can also be computed from Equation (14):

$$(1.00)(100)/10.0 = 10.0\ \mathrm{ft^3}$$

EFFICIENCY CALCULATIONS

In analyzing heating appliance efficiency, an energy balance is made that accounts (as much as possible) for disposition of all thermal energy released by combustion of the fuel quantity consumed. The various components of this balance are generally expressed in terms of Btu/lb of fuel burned or as a percentage of its higher heating value. The following are major components of an energy balance and their calculation methods:

1. Useful heat, or heat transferred to the heated medium; for convection heating equipment, this value q_1 is computed as the product of the mass rate of flow and enthalpy change.
2. Heat loss as sensible heat in the dry flue gases

$$q_2 = m_g c_{pg}(t_g - t_a) \tag{17}$$

   where m_g is calculated as in Equation (13).
3. Heat loss in water vapor in products formed by combustion of hydrogen

$$q_3 = (9\mathrm{H_2}/100)[(h)_{tg} - (h_f)_{ta}] \tag{18}$$

4. Heat loss in water vapor in the combustion air

$$q_4 = Mm_a[(h)_{tg} - (h_g)_{ta}] \tag{19}$$

   where m_a is calculated as in Equations (5) and (6).
5. Heat loss from incomplete combustion of carbon

$$q_5 = 10{,}143\ \mathrm{C}\left(\frac{\mathrm{CO}}{\mathrm{CO_2} + \mathrm{CO}}\right) \tag{20}$$

6. Heat loss from unburned carbon in the ash or refuse

$$q_6 = 14{,}600[(C_u/100) - \mathrm{C}] \tag{21}$$

7. Unaccounted-for heat losses, q_7

The following symbols are used in Equations (17) through (21):

q_1 = useful heat, Btu/lb of fuel
q_2 = heat loss in dry flue gases, Btu/lb of fuel
q_3 = heat loss in water vapor from combustion of hydrogen, Btu/lb of fuel
q_4 = heat loss in water vapor in combustion air, Btu/lb of fuel
q_5 = heat loss from incomplete combustion of carbon, Btu/lb of fuel
q_6 = heat loss from unburned carbon in ash, Btu/lb of fuel
q_7 = unaccounted-for heat losses, Btu/lb of fuel
c_{pg} = mean specific heat of flue gases at constant pressure (c_{pg} ranges from 0.242 to 0.254 Btu/lb·°F for flue gas temperatures from 300 to 1000°F), Btu/lb·°F
$(h)_{tg}$ = enthalpy of superheated steam at flue gas temperature and 14.7 psia, Btu/lb
$(h_f)_{ta}$ = enthalpy of saturated water vapor at air temperature, Btu/lb
$(h_g)_{ta}$ = enthalpy of saturated steam at combustion air temperature, Btu/lb
m_a = mass of combustion air per mass of fuel used, lb/lb of fuel
m_g = mass of dry flue gas per mass of fuel, lb/lb of fuel
t_a = temperature of combustion air, °F
t_g = temperature of flue gases at exit of heating device, °F
H_2 = hydrogen in fuel, % by mass (from ultimate analysis of fuel)
M = humidity ratio of combustion air, mass of water vapor per mass of dry air
CO, CO_2 = carbon monoxide and carbon dioxide in flue gases, % by volume
C = mass of carbon burned per unit of mass of fuel, corrected for carbon in ash, lb/lb of fuel

$$C = \frac{WC_u - W_a C_a}{100W} \tag{22}$$

where

C_u = percentage of carbon in fuel by mass from ultimate analysis
W_a = mass of ash and refuse
C_a = percent of combustible in ash by mass (combustible in ash is usually considered to be carbon)
W = mass of fuel used

Useful heat (item 1) is generally measured for a particular piece of combustion equipment.

Flue gas loss is the sum of items 2 through 6. However, for clean-burning gas- and oil-fired equipment, items 5 and 6 are usually negligible and flue gas loss is the sum of items 2, 3, and 4.

Flue gas losses (the sum of items 2, 3, and 4) can be determined with sufficient precision for most purposes from the curves in Figure 5, if O_2 content and flue gas temperature are known. Values of the losses were computed from typical ultimate analyses, assuming 1% water vapor (by mass) in the combustion air. Curves for medium-volatile bituminous coal can be used for high-volatile bituminous coal with no appreciable error.

Generally, item 5 is negligible for modern combustion equipment in good operating condition.

Item 6 is generally negligible for gas and oil firing, but should be determined for coal-firing applications.

Item 7 consists primarily of radiation and convection losses from combustion equipment surfaces and losses caused by incomplete combustion not included in items 5 and 6. Heat loss from incomplete combustion is determined by subtracting the sum of items 1 through 6 from the fuel heating value.

Radiation and convection losses are not usually determined by direct measurement. But if the heating appliance is located within the heated space, radiation and convection losses can be considered useful heat rather than lost heat and can be omitted from heat loss calculations or added to item 1.

If CO is present in flue gases, small amounts of unburned hydrogen and hydrocarbons may also be present. The small losses caused by incomplete combustion of these gases would be included in item 7, if item 7 was determined by subtracting items 1 through 6 from the fuel heating value.

The overall thermal efficiency of combustion equipment is defined as

$$\text{Thermal efficiency, \%} = 100\,\frac{\text{Useful heat}}{\text{Heating value of fuel}} \tag{23}$$

The following equation can be used to estimate efficiency for equipment where item 7 is small or radiation and convection are useful heat:

Thermal efficiency, % =

$$100\,\frac{\text{Heating value of fuel} - (q_2 + q_3 + q_4 + q_5 + q_6)}{\text{Heating value of fuel}} \tag{24}$$

Using heating values based on gas volume, the thermal efficiency of a gas appliance can be computed with sufficient precision by the following equation:

$$\eta = \frac{100(Q_h - Q_{fl})}{Q_h} \tag{25}$$

where

η = thermal efficiency, %
Q_h = higher heating value of fuel gas per unit volume
Q_{fl} = flue gas losses per unit volume of fuel gas

To produce heat efficiently by burning any common fuel, flue gas losses must be minimized by (1) providing adequate heat-absorbing surface in the appliance, (2) maintaining clean heat transfer surfaces on both fire and water or air sides, and (3) reducing excess air to the minimum level consistent with complete combustion and discharge of combustion products.

Seasonal Efficiency

The method just presented is useful for calculating the steady-state efficiency of a heating system or device. Unfortunately, the seasonal efficiency of a combustion heating system can be significantly different from the steady-state efficiency. The primary factor affecting the seasonal efficiency is flue loss during the burner-off period. The warm stack that exists at the end of the firing period can cause airflow in the stack while the burner is off. This airflow can remove heat from furnace and heat exchanger components, from the structure itself, and from pilot flames. Also, if combustion air is drawn from the heated space within the structure, the heated air lost must be at least partly replaced with cold infiltrated air. For further discussion of seasonal efficiency, see Chapter 9 of the *ASHRAE Handbook—Systems and Equipment*.

COMBUSTION CONSIDERATIONS

Air Pollution

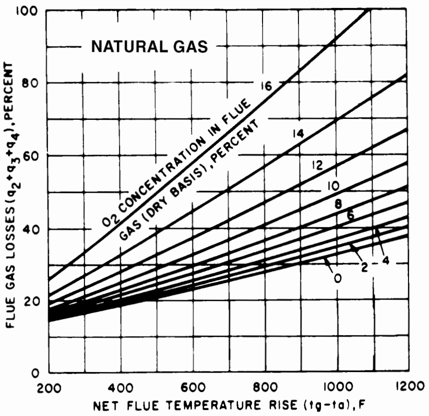
Combustion processes constitute the largest single source of air pollution. Pollutants can be grouped into four categories:

1. Products of incomplete fuel combustion
    - Combustible aerosols (solid and liquid), including smoke, soot, and organics, but excluding ash
    - Carbon monoxide, CO
    - Gaseous hydrocarbons
2. Oxides of nitrogen (generally grouped and referred to as NO_x)
    - Nitric oxide, NO
    - Nitrogen dioxide, NO_2
3. Emissions resulting from fuel contaminants
    - Sulfur oxides, primarily sulfur dioxide, SO_2, and small quantities of sulfur trioxide, SO_3
    - Ash
    - Trace metals
4. Emissions resulting from additives
    - Combustion-controlling additives
    - Other additives

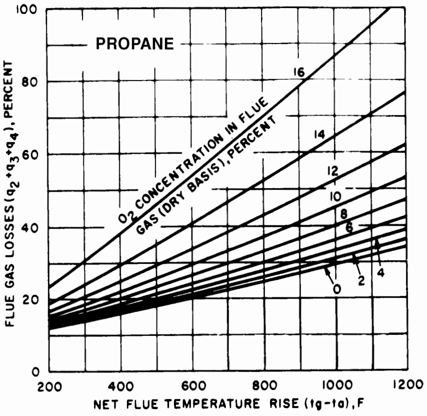
Emission levels of nitrogen oxides and products of incomplete combustion are directly related to the combustion process and can be controlled, to some extent, by process modification. Emissions due to fuel contaminants are related to fuel selection and are slightly affected by the combustion process. Emissions due to additives must be considered in the overall evaluation of the merits of using additives.

Nitrogen oxides are produced during the combustion process, either (1) by thermal fixation (reaction of nitrogen and oxygen at high combustion temperatures), or (2) from fuel nitrogen (oxidation of organic nitrogen in fuel molecules). Unfortunately, high excess air and high flame temperature techniques, which ensure complete fuel combustion, tend to promote NO_x formation.

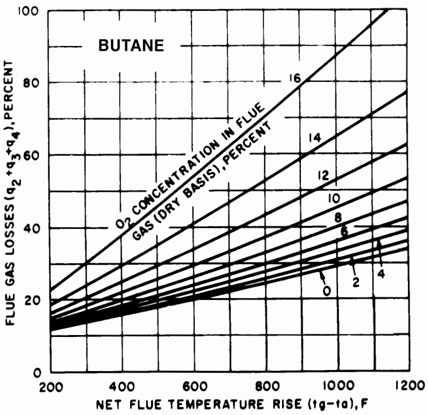
Table 12 lists NO_x emission factors for uncontrolled fuel-burning equipment (i.e., equipment that does not have exhaust gas recirculation, low-NO_x burners, or other emission controls). Differences in the NO_x emissions of fuels are caused by the flame temperature and different levels of fuel nitrogen. The data in Table 12 are adapted from EPA (1993), Compilation of Air Pollutant Emission Factors, which lists emission factors of a wide variety of equipment, as well as emission reduction options. Carbon monoxide emissions are less dependent on fuel type and typically range



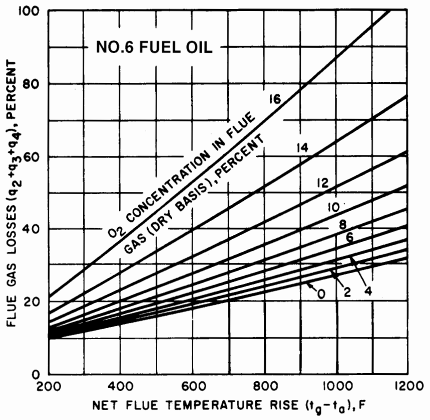
FUEL: NATURAL GAS
HEATING VALUE: 22,345 BTU/LB COMBUSTIBLES
H/C RATIO: 3.8



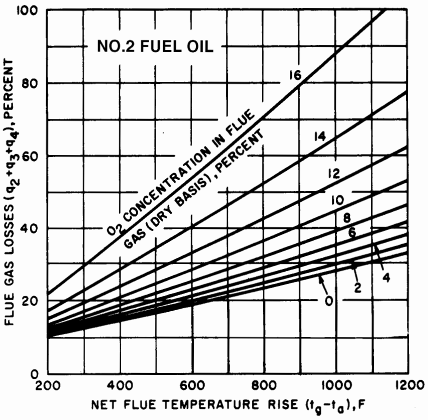
FUEL: PROPANE
HEATING VALUE: 21,646 BTU/LB COMBUSTIBLES
H/C RATIO: 2.667



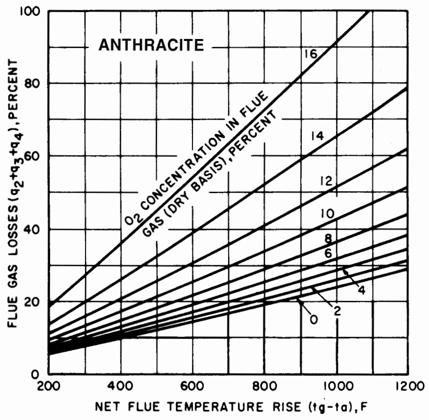
FUEL: BUTANE
HEATING VALUE: 21,180 BTU/LB COMBUSTIBLES
H/C RATIO: 2.5



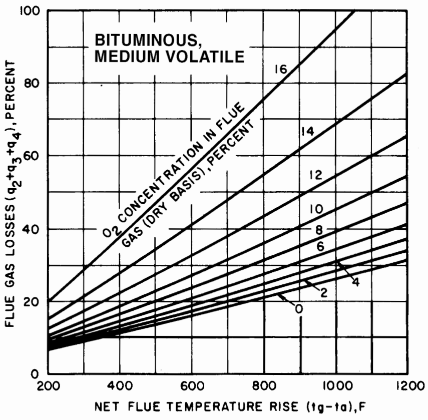
FUEL: NO. 6 FUEL OIL
HEATING VALUE: 19,000 BTU/LB COMBUSTIBLES
H/C RATIO: 1.5



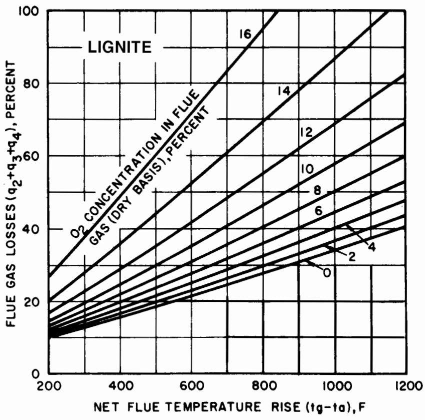
FUEL: NO.2 FUEL OIL
HEATING VALUE: 19,500 BTU/LB COMBUSTIBLES
H/C RATIO: 1.8



FUEL: ANTHRACITE
HEATING VALUE: 14,980 BTU/LB COMBUSTIBLES
H/C RATIO: 0.28



FUEL: BITUMINOUS, MEDIUM VOLATILE
HEATING VALUE: 15,500 BTU/LB COMBUSTIBLES
H/C RATIO: 0.68



FUEL: LIGNITE
HEATING VALUE: 12,560 BTU/LB COMBUSTIBLES
H/C RATIO: 0.79

Fig. 5 Flue Gas Losses with Various Fuels
(Flue gas temperature rise shown. Loss is based on 65°F room temperature.)

Table 12 NO_x Emission Factors for Combustion Sources Without Emission Controls

Source	NO_x Emission Factor, lb/10^6 Btu of Heat Input
Gas-Fired Equipment	
Small industrial boilers	0.14
Commercial boilers	0.10
Residential furnaces	0.09
Distillate-oil-fired small industrial boilers, commercial boilers, and residential furnaces	0.14
Residual oil-fired small industrial boilers and commercial boilers	0.37

from 0.03 to 0.04 lb/10^6 Btu of heat input. For gas-fired commercial and industrial boilers, particulate emissions range from 0.005 to 0.006 lb/10^6 Btu. For distillate-oil-fired commercial and industrial boilers, particulates are typically 0.014 lb/10^6 Btu. For residential oil-fired equipment, particulate emission factors are 0.003 lb/10^6 Btu. For residual-oil-fired equipment, particulate emissions depend on the sulfur content. For a sulfur content of 1%, the particulate emission rate is typically 0.083 lb/10^6 Btu.

Emission levels of products of incomplete fuel combustion can be reduced by reducing burner cycling, ensuring adequate excess air, improving the mixing of air and fuel (by increasing turbulence, improving distribution, and improving liquid fuel atomization), increasing residence time in the hot combustion zone (possibly by decreasing the firing rate), increasing combustion zone temperatures (to speed reactions), and avoiding quenching the flame before reactions are completed.

The relative contribution of each of these mechanisms to the total NO_x emissions depends on the amount of organic nitrogen in the fuel. Natural gas contains very little nitrogen. Virtually all NO_x emissions with gas firing are due to the thermal mechanism. The nitrogen content of distillate oil varies, but an average of 20 ppm of fuel NO_x is produced (about 20 to 30% of the total NO_x). The fuel nitrogen in residual oil can be significantly higher, with fuel NO_x contributing heavily to the total emissions.

Thermal fixation is strongly dependent on flame maximum temperature. For example, increasing the flame temperature from 2600 to 2800°F increases thermal NO_x tenfold. Therefore, methods to control thermal NO_x are based on methods to reduce the maximum flame temperature. Flue gas recirculation is perhaps the most effective method of reducing thermal NO_x in commercial and industrial boilers. In gas-fired boilers, NO_x reductions of 70% can be realized with 15-20% recirculation of flue gas into the flame. The NO_x reduction decreases with increasing fuel nitrogen content. With distillate-oil firing, reductions of 60-70% can be achieved. In residual-oil-fired boilers, flue gas recirculation can reduce NO_x emissions by 15 to 30%. The maximum rate of flue gas recirculation is limited by combustion instability and CO production.

Two-stage firing is the only technique that reduces NO_x produced both by thermal fixation and fuel nitrogen in industrial and utility applications. The fuel-rich or air-deficient primary combustion zone retards NO_x formation early in the combustion process (when NO_x forms most readily from fuel nitrogen), and avoids peak temperatures, reducing thermal NO_x. Retrofit low-NO_x burners that control air distribution and fuel air mixing in the flame zone can be used to achieve staged combustion. With oil firing, NO_x reductions of 20 to 50% can be obtained with low-NO_x burners. The application of flue gas recirculation and other control methods to residential, oil-fired warm air furnaces was reviewed by Butcher et al. (1994).

The following are some methods of reducing NO_x emissions from gas-fired appliances (Murphy and Putnam 1985):

- Burner adjustment
- Flame inserts (radiation screens or rods)
- Staged combustion and delayed mixing
- Secondary air baffling
- Catalytic and radiant burners
- Total premix
- Pulse

Radiation screens or rods (flame inserts) surrounding or inserted into the flame absorb radiation to reduce flame temperature and retard NO_x formation. Proprietary appliance burners with no flame inserts have been developed and produced to comply with the very strict NO_x emission limitations of California's Air Quality Management Districts.

The U.S. EPA sets limits on air pollutant emissions (Source Performance Standards) from boilers larger than 10 million Btu/h of heat input. In addition, states set emission regulations that are at least as strict at the federal limits and may apply to smaller equipment.

The EPA's automobile emission standard is 1.0 g of NO_2 per mile, which is equivalent to 750 ng/J of NO_x emission. California's maximum is 0.4 g/mile, equivalent to 300 ng/J. California's Air Quality Management Districts for the South Coast (Los Angeles) and the San Francisco Bay Area limit NO_x emission to 40 ng/J of useful heat for some natural gas-fired residential heating appliances.

For further discussion of air pollution aspects of fuel combustion, see EPA (1971a and 1971b).

Condensation and Corrosion

Fuel-burning systems that cycle on and off to meet demand cool down during the off-cycle. When the appliance starts again, condensate forms briefly on surfaces until they are heated above the dew-point temperature. Low-temperature corrosion occurs in system components (heat exchangers, flues, vents, chimneys) when their surfaces remain below the dew-point temperature of flue gas constituents (water vapor, sulfides, chlorides, fluorides, etc.) long enough to cause condensation. Corrosion increases as condensate dwell time increases.

Acids in the flue gas condensate are the principle substances responsible for low-temperature corrosion in fuel-fired systems. Sulfuric, hydrochloric, and other acids are formed when acidic compounds in fuel and air combustion products combine with condensed moisture in appliance heat exchangers, flues, or vents. Corrosion can be avoided by maintaining these surfaces above the flue gas dew point.

In high-efficiency, condensing-type appliances and economizers, flue gas temperatures are intentionally reduced below the flue gas dew-point temperatures to achieve efficiencies approaching 100%. In these systems, the surfaces subjected to condensate must be made of corrosion-resistant materials. The most corrosive conditions exist at the leading edge of the condensing region, especially those areas that experience evaporation during each cycle (Strickland et al. 1987). Drainage of condensate retards the concentration of acids on system surfaces. Regions from which condensate partially or completely drains away before evaporation are less severely attacked than regions from which condensate does not drain before evaporation.

The metals most resistant to condensate corrosion are stainless-steel alloys with high chromium and molybdenum content, and nickel-chromium alloys with high molybdenum content (Stickford et al. 1988). Aluminum experiences general corrosion rather than pitting when exposed to flue gas condensate. If applied in sufficiently thick cross section to allow for metal loss, aluminum can be used in condensing regions. Most ceramic and high-temperature polymer materials resist the corrosive effects of flue gas condensate. These materials may have application in the condensing regions, if they can meet the structural and temperature requirements of a particular application.

In coal-fired power plants, the rate of corrosion for carbon steel condensing surfaces by the mixed acids (primarily sulfuric and hydrochloric) is reported to be maximum at about 122 ± 18°F (Davis 1987). Mitigation techniques include (1) acid neutralization with a base such as NH_3 or $Ca(OH)_2$; (2) use of protective linings of glass-filled polyester or coal-tar epoxy; and (3) replacement of steel with molybdenum-bearing stainless steels, nickel alloys, polymers, or other corrosion-resistant materials. Other elements in residual fuel oils and coals that contribute to high-temperature corrosion include sodium, potassium, and vanadium. Each fuel-burning system component should be evaluated during installation, or when modified, to determine the potential for corrosion and the means to retard corrosion (Paul et al. 1988).

Soot

Soot deposits on flue surfaces of a boiler or heater act as an insulating layer over the surface, reducing heat transfer to the water or air. Soot can also clog flues, reduce draft and available air, and prevent proper combustion. Proper burner adjustment can minimize soot accumulation. The use of off-specification fuel can contribute to the generation of soot.

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