



Introduction to Central Boiler Plants

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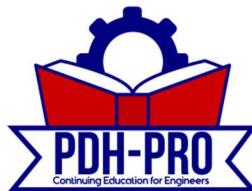
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CENTRAL BOILER PLANTS

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CHAPTER 1

GENERAL CONSIDERATIONS

SECTION I. INTRODUCTION

1-1. PURPOSE

The purpose of this manual is to provide information and guidance on the installation, operation, and maintenance of U.S. Army Central Boiler Plant equipment. Efficient plant operation becomes more important with each increase in the cost of fuel and equipment. The Central Plant operator has an important job in achieving and maintaining maximum efficiency of plant operation. The information and guidance in this manual should be reviewed as a first step toward achieving efficient plant operation.

1-2. CENTRAL BOILER PLANTS

The primary purpose of a Central Boiler Plant is to economically produce energy for distribution. This energy may be in the form of steam, hot water, or occasionally, compressed air or electric power. A distribution system is necessary to carry this energy to buildings, hospitals, kitchens, and laundries where it is used for heating, cooling, process, sterilization, and production of domestic hot water. Condensate or hot water is returned to the Central Boiler Plant where it is reheated in a boiler and returned to the distribution system for recycle.

a. Types of Central Boiler Plants. Energy for heating or process use is generally produced in one of five forms:

Low Temperature Water	LTW (up to 250° F, less than 160 psig)
Medium Temperature Water	MTW (251° F to 350° F)
High Temperature Water	HTW (351° F to 450° F)
Low Pressure Steam	LPS (up to 15 psig)
High Pressure Steam	HPS (above 15 psig)

The type of Central Boiler Plant built depends upon the requirements of the specific installation. For applications involving only space heating and domestic water, a low temperature water plant is generally sufficient. If steam is required for large process loads or electric generation, a steam plant must be constructed. For most other installations, an economic evaluation must be performed to compare the costs of a high temperature water system to those of a steam system. Such an evaluation usually shows the high temperature water plant to be more economical. The following paragraphs provide a brief comparison of the major types of central heating plant systems.

b. Comparison of High Temperature Water and Steam.

The major advantages of high and medium temperature water systems result from the closed-loop distribution system. The closed loop system recycles the unused energy in the water and results in very small system water losses. By comparison, steam distribution systems include condensate return systems with potentially significant energy and water losses due to steam flashing, defective traps, defective pressure reducing valves, pipe leaks, and unreturned process steam. The advantages of high and medium temperature water systems are further discussed in the following paragraphs.

(1) Energy Losses from a Steam System. Figures 1-1 and 1-2 illustrate the heat balance at a heat exchanger for 100 psig and 15 psig steam/condensate system, respectively. When 100 psig steam is supplied to a heat exchanger, the condensed water is at a temperature of 338° F and contains 26 percent of the energy originally supplied in the steam. When the condensate discharges from the trap, 13 percent of the water flashes to steam and the remaining condensate is at a temperature of 212° F. When 15 psig steam is supplied, the condensed water contains 19 percent of the original energy at a temperature of 250° F. When the condensate discharges from the trap, 4 percent of the water flashes to steam. The energy losses and makeup water requirements of the low pressure system are thus lower, making the low pressure system preferable if a steam system is used.

(2) Pressure Reducing Valves and Vent Condensers. The pressure reducing valve supplies the heat exchanger with low pressure steam, thus minimizing flash-losses. If a vent condenser is not supplied, the flash-off steam is lost. If a portion of the condensate is not returned to the central boiler plant for any reason, the portion of the energy remaining in the condensate is lost. For example, if a 100 psig system has 20 percent condensate loss, 5.2 percent ($.20 \times .26 = .052$) of the total energy produced is wasted. In addition, 20 percent treated make-up water is needed to keep the system operating. Procedures for monitoring and controlling condensate losses are further discussed in paragraph 3-2.

(3) Heat Balance for an HTW System. Figure 1-3 illustrates a heat balance for a high temperature water system at a heat exchanger. It is informative to compare the high temperature water system with 100 psig steam system. In both cases, 1125 lbs of water is heated from 50° F to 140° F by the heat exchanger. The high temperature

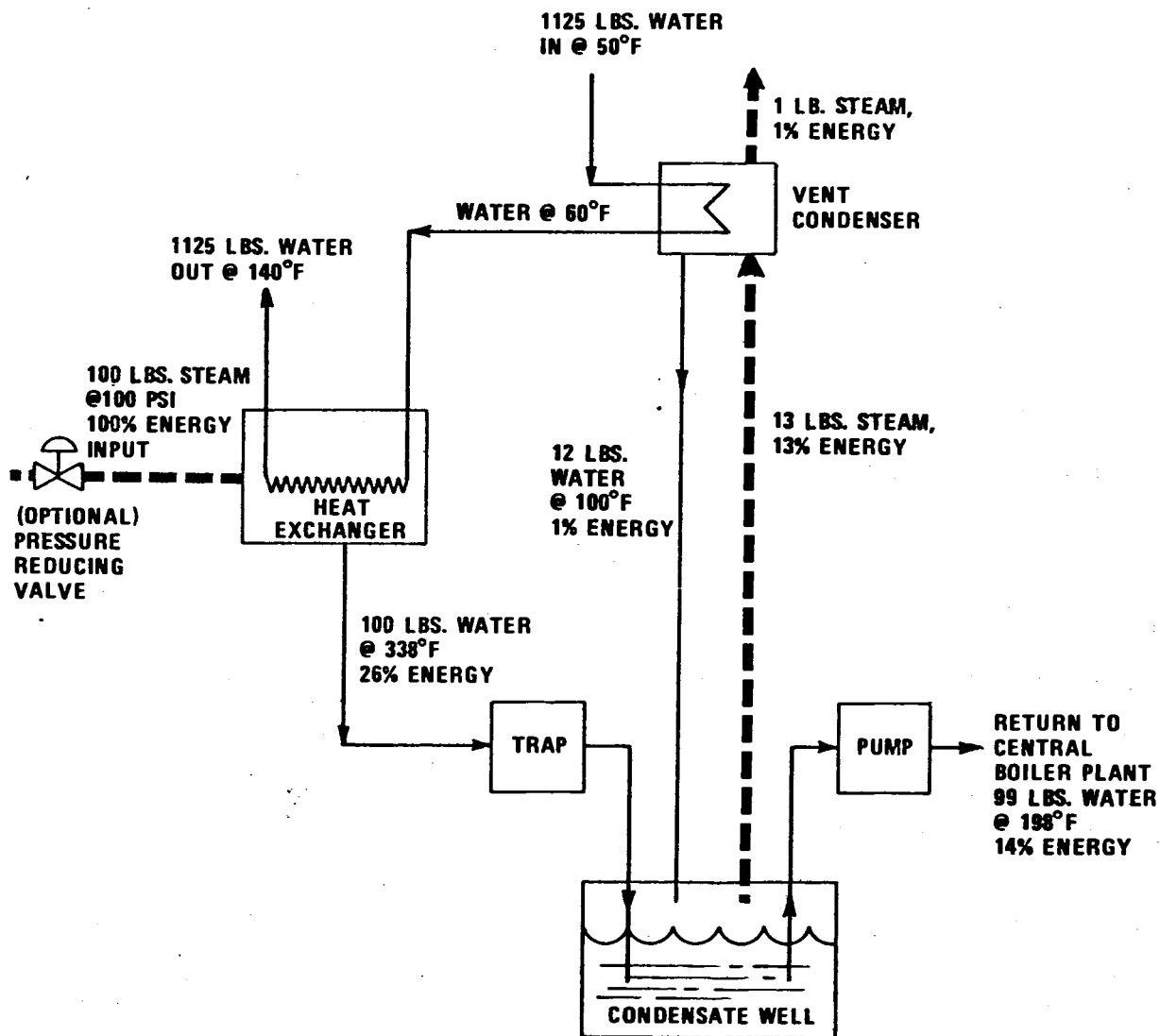


FIGURE 1-1. 100 PSI STEAM HEAT BALANCE

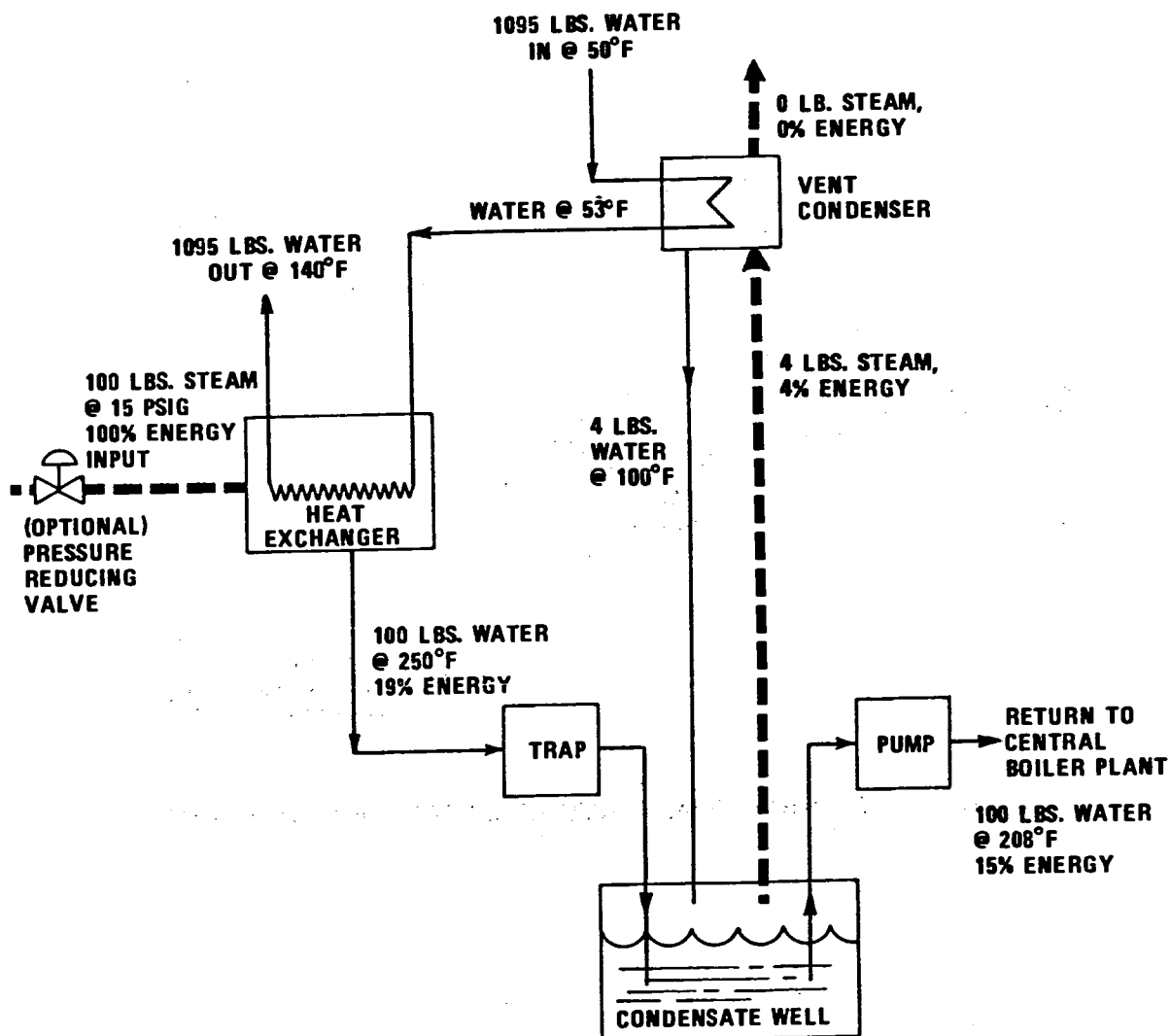


FIGURE 1-2. 15 PSI STEAM HEAT BALANCE

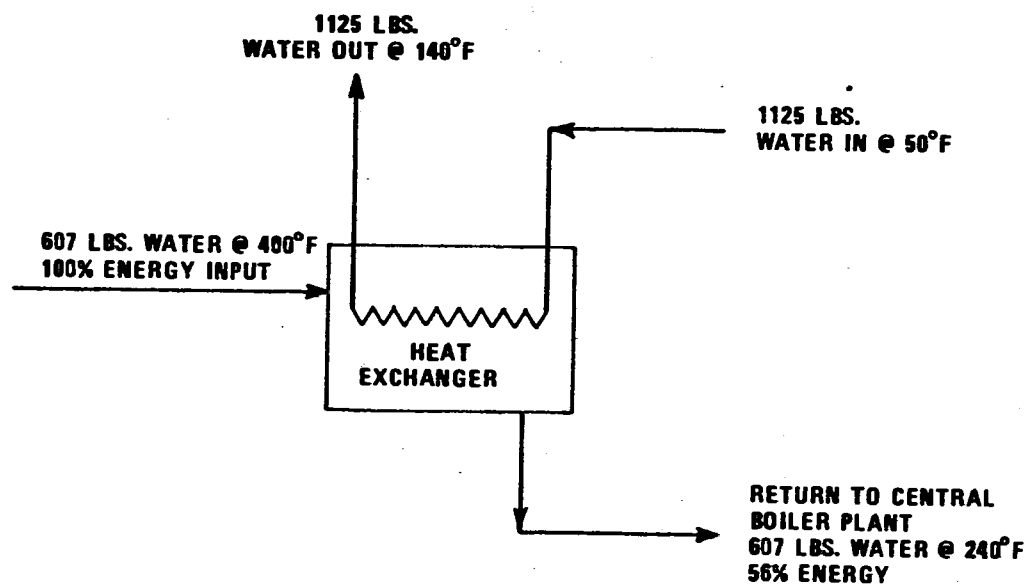


FIGURE 1-3. HIGH TEMPERATURE WATER HEAT BALANCE

water system returns 56 percent of the energy input to the heat exchanger while the steam system returns 14 percent. The high temperature water system does not have steam flashing losses or condensate losses. The HTW system is clearly a more efficient means of distributing energy from a central boiler plant, if the process requirements of the system are such that it is applicable. Appendix C provides Heat Balance Calculations explaining these numbers.

(4) **Corrosion.** A major advantage of the high temperature water closed-loop distribution system is an inherent reduction in distribution system corrosion as compared to steam/condensate distribution systems. Maintenance, pipe replacement, and energy costs associated with line leaks are thereby reduced, resulting in a significant savings.

(5) **Stored Thermal Energy.** The large amount of stored thermal energy in an HTW and MTW distribution system allows for more effective response to short-duration peak load requirements. Boiler load swings are reduced, and more accurate combustion control is possible. HTW and MTW plants are generally sized for peak loads 10 to 20 percent less than steam plants because of the stored thermal capacity in the system.

(6) **Safety.** High and medium temperature water systems are safer than steam. In the event of a line rupture, the stored thermal energy in the water is dissipated by accelerating the water to higher velocities and flashing it to steam. A fine spray of 180° F water occurs, ending one to two feet from the rupture. The amount of energy exiting a ruptured high temperature water line is only 5 to 10 percent of the energy exiting a ruptured steam line of the same size.

(7) **Water Treatment.** Due to the low makeup water requirements, the capacity of a water treatment system for an HTW and MTW plant is a small fraction of that required for a steam plant. This provides a cost savings in equipment, maintenance, and chemical use requirements. Steam plants require more complex water treatment systems including a deaerator (not required in HTW or MTW plants) to provide oxygen-free water. If not carefully controlled, the deaerator can vent steam, resulting in energy losses. Steam boilers also require blowdown to maintain acceptable water quality, which contributes to makeup water requirements and plant energy losses. Blowdown is less or not required at all in a hot water boiler.

(8) **Loss of Steam Pressure and Quality.** If the distribution lines are long, significant reductions in steam pressure and quality (100% quality = 100% steam, 90% quality = 90% steam and 10% liquid water, etc.) can occur due to line friction and heat losses.

c. **Low Temperature Water.** Low temperature water plants have all the basic advantages of HTW and MTW

plants relative to steam plants. In addition, the lower system pressure associated with LTW provides a cost advantage due to the lower pressure ratings required for boilers, accessories, and piping. However, LTW plants cannot provide energy at temperatures required for many process, hospital, and laundry applications, thus eliminating them from consideration for many installations.

1-3. EQUIPMENT

A Central Boiler Plant is comprised of ten major categories of equipment, as described below.

a. **Heat-Absorbing Equipment.** Heat (energy) from the combustion of fuel is transferred to the boiler water to generate steam or hot water in the furnace and generating sections of the boiler. Economizers are sometimes provided to recover heat from the boiler flue gases (products of combustion) and transfer it to the feedwater. Heat from the flue gases can also be absorbed by air heaters for transfer to the combustion air before it enters the furnace through the burner or stoker grate. Plant efficiency is closely related to the ability of the boiler, economizer, or air heater to absorb heat from the products of combustion.

b. **Fuel-Handling Equipment.** Coal-burning plants require facilities for storage of coal, and equipment for moving the coal to storage and reclaiming and transferring it at the boiler. Provisions are usually made to move the coal directly from the delivery point to the boiler. Mechanical, pneumatic, or hydraulic ash removal systems are necessary in coal-burning plants to dispose of ash from the boiler, stoker, and dust collector hoppers. Oil-burning plants require one or more oil-storage tanks with associated transfer pumps, tank heaters, connecting piping, tank level meters, flow meters, and day tanks. Pumping equipment and piping to the burners will be required and oil heaters may be required depending upon the oil used. Ash removal equipment may be required in some cases. Gas-burning plants will have a gas pressure reducing station (shut-off valve, strainer, pressure reducing valve, safety-relief valve, and gas meter) to reduce the incoming line pressure required in the distribution piping and burners.

c. **Combustion Equipment.** Combustion equipment for oil and gas firing consists of safety shut-off valves, safety devices or interlocks, control valves, and burner(s). The function of the burner is to ignite and burn the fuel by efficiently and completely mixing it with combustion air in the furnace. Coal may be fired manually on grates or automatically by stokers, or burned in suspension in a pulverized furnace or fluidized bed.

d. **Air-Handling Equipment.** In order to achieve efficient combustion of fuel, the amount of air delivered to the burner or stoker must be properly matched to the amount of fuel. Forced draft fans with associated control dampers

are used to provide combustion air. Overfire air and reinjection fans for stokers and primary air fans for pulverizers may also be required. Induced draft fans are used to pull the flue gas from the furnace through the boiler bank and any ductwork, economizer, air heater, or dust collector provided.

e. Controls and Instrumentation. Since operator safety and protection of the boiler are of great importance, boiler feedwater controls and burner safety controls are required to guard against failures due to low boiler water or explosion. Combustion controls regulate the fuel and air flow to maintain efficient combustion. The high price of boiler fuel which justifies improved combustion controls also justifies the use of recorders and meters to monitor combustion and ensure optimum plant operation.

f. Pollution Control Equipment. The combustion of fuel may generate a variety of pollutants in excess of limits set by regulatory agencies. The major pollutant emissions of present concern are particulate, oxides of sulfur (SO_x), and oxides of nitrogen (NO_x). The use of a fuel lower in ash or sulfur content and modifications to the combustion process can be effective in reducing these emissions. If these fuels are too expensive or combustion modifications only partially effective, pollution control systems can also be used to bring emissions within acceptable limits. Typical pollution control systems are mechanical collectors, fabric filters, electrostatic precipitators, wet scrubbers, and tall stacks.

g. Water Treatment Systems. Proper water treatment prevents scale formation on the internal surfaces of the boiler and reduces boiler and distribution system corrosion.

Water treatment often involves a combination of external and internal techniques. External water treatment includes removal of suspended matter with clarifiers and filters; reduction of water hardness with lime or zeolite softeners or demineralizers; and reduction of corrosive gases with deaerators. Internal water treatment involves injection of chemicals directly into the boiler to control any impurities remaining after external treatment. Chemicals include caustic to aid precipitation, phosphate for hardness removal, and dispersants to aid precipitate removal by blowdown. Specific equipment is also required for boiler blowdown systems and testing purposes to monitor and maintain a functional water treatment system.

h. Water Supply Equipment. Feedwater is supplied to steam boilers by means of centrifugal or reciprocating pumps. Centrifugal pumps are also typically used to circulate water through high temperature water boilers and their associated distribution systems.

i. Distribution Systems. The energy produced in the central boiler plant, whether in the form of steam or hot water, must be transferred to other buildings through a distribution system. The distribution system also returns unused energy in the form of hot water or condensate to the central plant for recycle. The distribution system consists of insulated, weatherproof pipelines, valve pumps, regulators, and heat exchangers. Steam systems also include traps and condensate handling of equipment.

j. Miscellaneous. Each central boiler plant has its own unique set of maintenance tools and spare parts inventory. Also unique to a given plant is its electric power distribution system, air compressors, and emergency generator sets.

SECTION II. ELEMENTARY COMBUSTION PRINCIPLES

1-4. FOSSIL FUELS

Fossil fuels are derived from the remains of plant and animal organisms. These organisms used carbon dioxide (CO₂), minerals, water, and energy from sunlight to grow. Over millions of years this material accumulated and the original carbohydrates and other organic materials were buried and converted to the hydrocarbon or fossil fuels we use today. These fossil fuels are found in solid, liquid, and gaseous form.

a. Coal. Coal is a solid fossil fuel. Coal's characteristics are directly affected by its age, since the plant matter from which it was formed first changes to peat, then with sufficient heat, pressure, and time to brown coal or lignite, subbituminous coal, bituminous coal, and finally anthracite — the oldest of coals. If anthracite were submitted to additional pressure and heat, graphite and eventually diamonds would be produced. Considering the

cost of coal today, it is worth thinking of coal as young diamonds.

(1) In the United States, lignite is found primarily in North Dakota, Montana, and Texas, with proven reserves of 447 billion tons. Subbituminous coal is found in Montana, Wyoming, Washington, and Alaska with proven reserves of 437 billion tons. Bituminous coal is found in at least twenty-eight states with proven reserves of over 800 billion tons. Anthracite is found in Pennsylvania, Alaska, Arkansas, and Virginia with proven reserves of 25 billion tons. Because of its widespread availability and subsequently lower transportation costs, bituminous coal is most frequently used. Table 1-1 outlines the classification of coals as given by ASTM D 388. This standard establishes ranges for fixed carbon, volatile matter, and heating value for each class and group of coals.

(2) Coal is a highly complex fuel. Most of its heating value exists in the form of carbon, which is present

Table 1-1. Classification of Coal

Class	Group	Fixed Carbon Limits Percent (Dry, Mineral- Matter-Free Basis)			Volatile Matter Limits, Percent (Dry, Mineral- Matter-Free Basis)			Calorific Value Limits Btu Per Pound (Moist, Mineral- Matter-Free Basis)		
		Equal or Greater Than	Less Than		Greater Than	Equal or Less Than		Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	--		--	2		--	--	
	2. Anthracite	92	98		2	8		--	--	
	3. Semianthracite	86	92		8	14		--	--	
II. Bituminous	1. Low volatile bituminous coal	78	86		14	22		--	--	
	2. Medium volatile bituminous coal	69	78		22	31		--	--	
	3. High volatile A bituminous coal	--	69		31	--	14 000	14 000	14 000	
	4. High volatile B bituminous coal	--	--		--	--	13 000	13 000	13 000	
	5. High volatile C bituminous coal	--	--		--	--	11 500	11 500	11 500	
III. Subbituminous	1. Subbituminous A coal	--	--		--	--	10 500	10 500	11 500	
	2. Subbituminous B coal	--	--		--	--	9 500	9 500	10 500	
	3. Subbituminous C coal	--	--		--	--	8 300	8 300	9 500	
IV. Lignite	1. Lignite A	--	--		--	--	6 300	6 300	8 300	
	2. Lignite B	--	--		--	--	--	--	6 300	

in two forms, fixed carbon and volatile matter. Volatile matter consists of easily gasified carbohydrates and hydrocarbons. The relationship between these two forms of carbon is one of primary factors in determining how readily a particular coal burns. Coal analyses may be provided in one of two forms, proximate and ultimate. A proximate analysis includes moisture, volatile matter, fixed carbon, ash, and sulfur on a percent by weight basis. An ultimate analysis includes moisture, carbon, hydrogen, sulfur, nitrogen, oxygen, and ash. These analyses may be given on either an as-received or dry basis, or occasionally on a moisture and ash free basis. Coal is also analyzed for heating value, in Btu/lb, and sometimes for ash chemical analysis and fusion temperatures. Ash-fusion temperatures are important because they are related to slag and ash deposits which can cause operational problems within the boiler or furnace.

b. Oil. Oil is a liquid fossil fuel, normally found far underground (to a depth of five miles or more). Oil and natural gas are as old or older than coal and are the products of marine plants and organisms which were buried and transformed by bacteria and chemical action into complex hydrocarbons. The oil and gas thus formed moved through the sedimentary rock in which it was buried until it was trapped in pockets below solid rock. In general, the deeper in the ground the oil and gas are found, the higher their age and quality. The oil we burn today can come from paraffin base, asphalt base, naphthene base or mixed base crude oil. This oil is refined by fractional distillation at low temperatures and pressure to separate the light ends (straight run No. 1 and No. 2 oil) from the heavier residual oil. The residual oil may be further processed by cracking, catalytic reforming or other processes to produce lighter oils such as cracked No. 2 distillate. Cracked oil contains more olefinic and aromatic hydrocarbons and is more difficult to burn than the paraffinic and naphthenic hydrocarbons found in straight run oil. The "Standard Specification for Fuel Oils" is defined in ASTM D 396. Table 1-2 "Detail Requirements for Fuel Oils" establishes limits for many of the key properties of fuel oil for the various standard grades. Table 1-3 relates API gravity to specific gravity, density, and higher heating value of fuel oils. Knowing the grade and specifications of an oil is only a start toward understanding its handling and combustion characteristics. Because sulfur limits are often imposed on fuel oil, refiners and distributors may blend different oils to meet sulfur limits. For example low sulfur No. 4 oil could be a blend of low sulfur No. 2 and high or medium sulfur No. 6 oil. Problems associated with blended oils may include widely varying viscosity, sludge precipitation, and stratification of the different components. Fairly recent problems have been related to No. 4 oil refined from imported paraffin base crude. Paraffin wax from the

oil can plate out and clog strainers, even though the oil is fluid. Heating the oil to 90 to 100° F will usually solve this problem. With oil coming from literally every corner of the world, the possible variations are endless and can change with each new tankful. Some of the more common problems are further discussed in chapter 3.

c. Natural Gas. Natural gas was formed by the same processes which produced oil. Compared with coal and oil, natural gas is a simple fuel consisting primarily of methane (CH_4 , 77% to 90% by volume) and ethane (C_2H_6 , 5% to 15% by volume). Propane and other more complex hydrocarbons are present in small quantities, and inert components such as carbon dioxide and nitrogen may range from 1% to 9% by volume. Typical natural gas has a higher heating value of 1,000 Btu per cubic foot and a specific gravity of 0.6 relative to air. Care is required in handling of natural gas in the vapor state. If leaks in the piping exist, the gas will escape and can be explosive if allowed to collect. Commercial pipeline natural gas has a distinctive "sweet" smell which helps to identify any leakage.

d. Alternate Fuels. Due to rising fuel costs and occasional shortages, it is becoming common to utilize wood, wood waste, municipal waste, agricultural by-products and other wastes to supplement our fossil resources. These alternate fuels may be mixed with more conventional fuels or burned by themselves to reduce the consumption of coal, oil, or gas. This trend will undoubtedly continue and accelerate.

1-5. COMBUSTION

Combustion can be defined as the rapid oxidation of fuel. It is a chemical reaction in which energy is released, in the form of heat and light, when fuel and oxygen combine. Rapid oxidation will not occur without heat to start the reaction. FUEL, OXYGEN, HEAT, and a chemical reaction are necessary for combustion to take place. If any one of these elements is removed, combustion stops. During combustion in a boiler it is important to control the fuel, oxygen, and heat so that the fuel is completely burned and the maximum use is made of its energy. To achieve controlled and efficient combustion three factors must be considered: TIME, TEMPERATURE, and TURBULENCE. Although the oxidation is rapid, several seconds may be required to start and complete the combustion process. Temperature varies during the combustion process with minimum temperatures occurring at the beginning and end. Turbulence is necessary to allow the fuel to be intimately mixed with the oxygen.

a. Chemical Reactions. The following general chemical reactions occur as the combustible carbon (C-molecular weight (MW) = 12), hydrogen (H_2 - MW = 2), and sulfur (S-MW = 32) combine with oxygen (O_2 -MW = 32) to form carbon dioxide (CO_2 -MW = 44), water (H_2O -MW

Table 1-2. Standard Specification for Fuel Oils

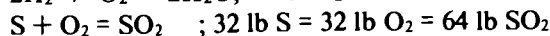
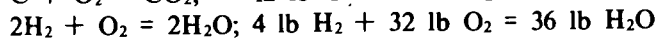
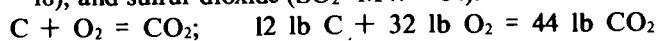
Grade of Fuel	Flash Point °C (°F)		Pour Point °C (°F)		Water and Sediment Vol %		Carbon Residue on 10% Bottoms, Weight %		Distillation Temperatures, °C (°F)			Saybolt Viscosity, 5 Universal Fuel			Specific Gravity 60/60°F (Degree API)		Copper Strip Corrosion		Sulfur %
	Min	Max	Min	Max	Min	Max	Min	Max	10% Point	90% Point	Max	Min	Max	Min	Max	Max	Max	Max	Max
No. 1 Distillate	38 (100)	-18 (0)			0.05		0.15		215 (420)	--	288 (550)	--	--	--	--	0.8499 (35 min)	No. 3		0.5
No. 2 Distillate	38 (100)	-6 (20)			0.05		0.35		--	282 (540)	338 (640)	32.6	37.9	--	--	0.8762 (30 min)	No. 3		0.5
No. 4 Light Residual	55 (130)	-6 (20)			0.50		--	0.10	--	--	--	45	125	--	--	--	--	--	--
No. 5 Light Residual	55 (130)	--			1.00		--	0.10	--	--	--	125	300	--	--	--	--	--	--
No. 5 Heavy Residual	55 (130)	--			1.00		--	0.10	--	--	--	300	900	23	40	--	--	--	--
No. 6 Heavy Residual	60 (140)	--			2.00		--	--	--	--	--	900	9000	45	300	--	--	--	--

Table 1-3. Fuel Oil Characteristics

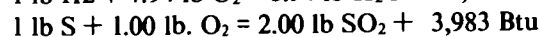
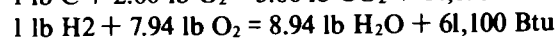
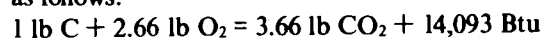
API Gravity	Specific Gravity	Density lb/gal	Higher Heating Value	
			Btu/lb	Btu/gal
5	1.037	8.633	17,980	155,470
10	1.000	8.328	18,260	152,280
15	0.966	8.044	18,500	149,030
20	0.934	7.778	18,740	145,880
25	0.904	7.529	18,940	142,820
30	0.876	7.273	19,130	139,660
35	0.850	7.076	19,300	136,720
40	0.825	6.870	19,450	133,760
45	0.802	6.675	19,590	130,910

API Gravity ranges for the fuel oil grades are: No. 1 Oil-46 to 41, No. 2 Oil-39 to 30, No. 4 Oil-28 to 24, No. 5 Oil-22 to 18, No. 6 Oil-17 to 9.

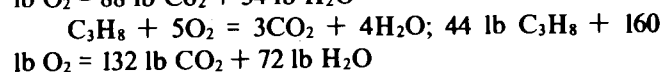
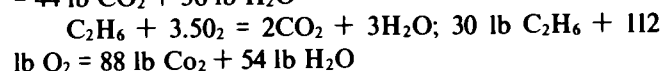
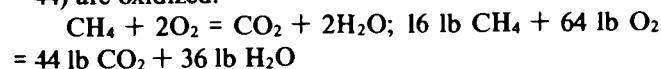
= 18), and sulfur dioxide (SO_2 - MW = 64):



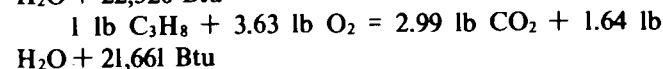
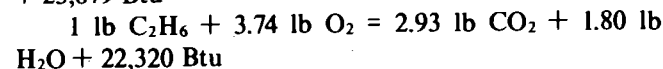
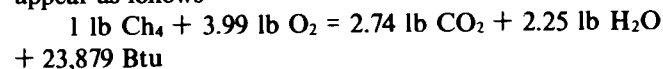
These equations may also be written on a weight basis as follows:



(1) The following general chemical reactions occur when the simplest hydrocarbon gases, methane (CH_4 -MW = 16), ethane (C_2H_6 -MW = 30), and propane (C_3H_8 -MW = 44) are oxidized:



On the basis of weight per pound of fuel, these equations appear as follows



(2) In some cases, the oxygen only partially oxidizes to form carbon monoxide (CO) which can then oxidize to form carbon dioxide. A large number of intermediate compounds of carbon, hydrogen and oxygen may also be formed between the start of the combustion process and the final products of combustion listed above. These intermediates are of little practical interest to the boiler operator. The heat of combustion listed above for each reaction is in British Thermal Units (Btu) and is called **HIGHER HEATING VALUE (HHV)**. Some of the heat of combustion (970 Btu per 1 lb H_2O produced) is used to form water and keep it in the vapor state. If this amount of heat is subtracted from the heating values shown above, a quantity called **LOWER HEATING VALUE (LHV)** is obtained. The common practice in the U.S. is to use higher heating value in combustion calculations, while lower heating value is typically used in Europe. General chemical reactions are a good way to calculate fuel and air requirements. They begin to explain combustion and boiler efficiency.

b. Air Requirements. The air we breathe is 76.7% nitrogen and 23.3% oxygen by weight or 79% nitrogen and 21% oxygen by volume. We use air to obtain oxygen for the combustion process. Each pound of air contains .233 pounds of oxygen. To obtain one pound of oxygen requires 4.29 pounds of air. This is calculated as follows:

$$4.29 \text{ lb air} \times \frac{0.233 \text{ lb oxygen}}{1.0 \text{ lb air}} = 1.0 \text{ lb oxygen}$$

Each 4.29 pounds of air contains 1 pound of oxygen and 3.29 pounds of nitrogen. The nitrogen is not chemically active in the combustion process; however, it lowers the flame temperature by absorbing heat and carrying it away from the boiler in the flue gas. The combustion equation given in the previous paragraph can be used to calculate the exact quantity of oxygen, and hence air, required to completely react with a given amount of fuel. This quantity of air is called **THEORETICAL AIR**. Unfortunately, the use and control of the combustion process in a boiler is not perfect and an additional quantity of air called **EXCESS AIR** is needed to achieve complete combustion.

c. Excess Air Example. Combustion of one pound of No. 2 oil with an analysis of 87 percent carbon, 12 percent hydrogen, 0.5 percent sulfur, and 0.5 percent nitrogen requires theoretical air as determined below:

$$.87 \text{ lb C} \times 2.66 \text{ lb O}_2 / \text{lb C} = 2.31 \text{ lb O}_2$$

$$.12 \text{ lb H}_2 \times 7.94 \text{ lb O}_2 / \text{lb H}_2 = 0.95 \text{ lb O}_2$$

$$.005 \text{ lb S} \times 1.00 \text{ lb O}_2 / \text{lb S} = 0.01 \text{ lb O}_2$$

$$\text{Theoretical Oxygen} = 3.27 \text{ lb O}_2$$

In a moderately well-controlled burner approximately 20 percent excess air is typically required to ensure complete combustion.

Theoretical air = $3.27 \text{ lb O}_2 \times 4.29 \text{ lb air} / \text{lb O}_2 = 14.0 \text{ lb air}$. The total combustion air per pound of fuel required thus becomes:

$$14.0 \text{ lb air} + (14.0 \text{ lb air} \times .20) = 16.8 \text{ lb air.}$$

If the combustion process is not well controlled, 50 percent excess air may enter the furnace through the burner. The total combustion air per pound of fuel then becomes:

$$14.0 \text{ lb. air} + 1(14.0 \text{ lb air} \times .50) = 21.0 \text{ lb. air.}$$

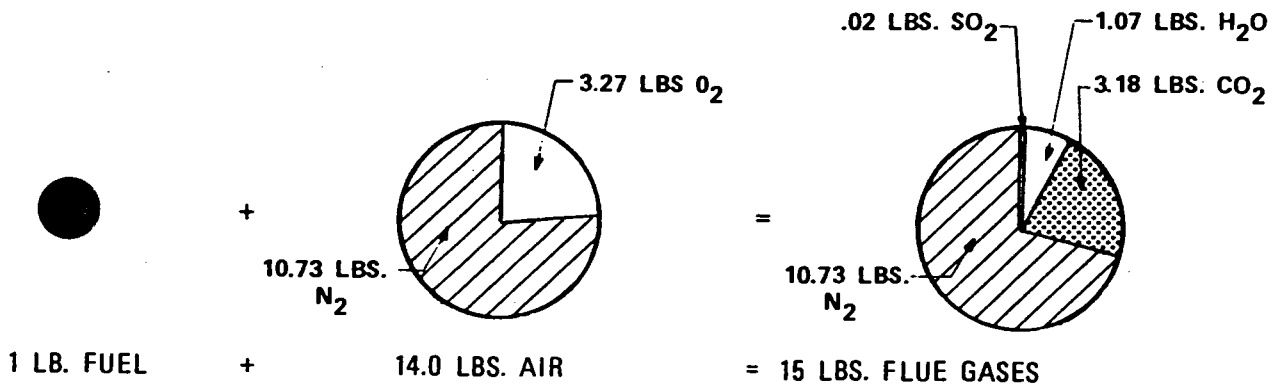
Figure 1.4 illustrates these relationships and the combustion products.

d. Higher Heating Values. Higher heating values of fuels are best determined by calorimeter test. If the ultimate analysis of an oil or coal is known, Dulong's formula may be used to determine HHV of a liquid or solid fuel. Dulong's formula is given below and may be considered accurate to within 2 or 3 percent.

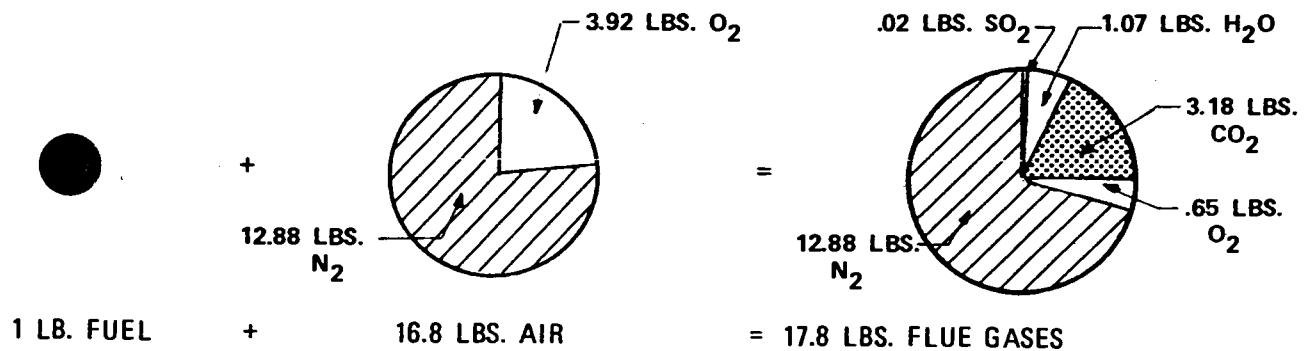
$$\text{HHV} = 14,544\text{C} + 62,028 (\text{H}_2 - \text{O}_2/8) + 4050 \text{ S}$$

The carbon, hydrogen, oxygen, and sulfur come from the ultimate analysis and are expressed in percent by weight. The coefficients represent the approximate heating values of the constituents in Btu/lb and the result obtained is also in Btu/lb. The $\text{O}_2/8$ is a correction applied to the hydrogen in the fuel to account for the fact that some of the hydrogen is already combined with oxygen to form water. The Dulong formula is not suitable for gaseous fuels because the heat of formation of constituents like methane and ethane is not considered. For gaseous fuels the HHV

COMBUSTION WITH THEORETICAL AIR



COMBUSTION WITH THEORETICAL AIR + 20% EXCESS AIR



COMBUSTION WITH THEORETICAL AIR + 50 % EXCESS AIR

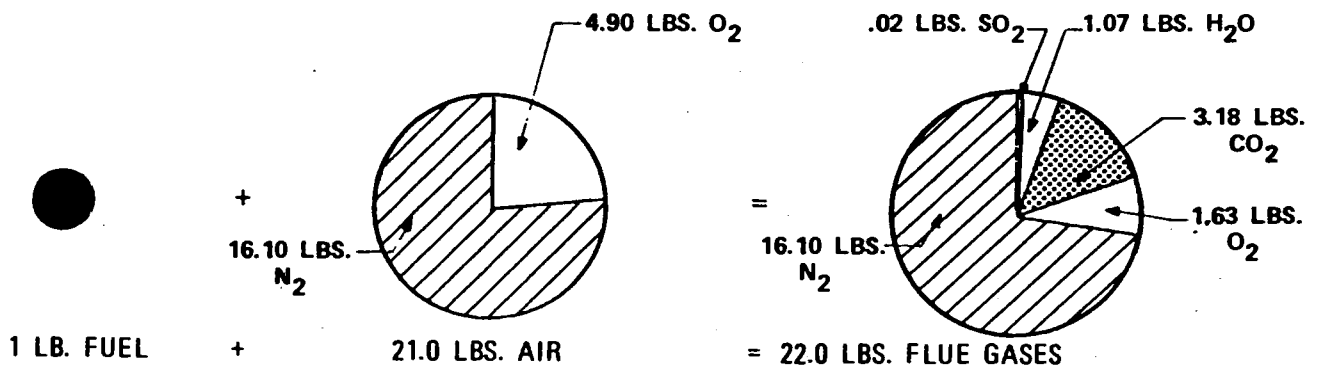


FIGURE 1-4. COMBUSTION OF OIL

may be determined by taking a weight average of heating values for each gaseous constituent. Care must be taken in evaluating the heating value of fuel oils. A No. 6 fuel oil may have a lower heating value than a No. 2 oil when measured on a Btu/lb basis, but since it is more dense, the No. 6 oil could well have more Btu/gallon. This is significant since oil is normally purchased by the gallon rather than by the pound. Table 1-3 provides a comparison of the API gravity, specific gravity, Btu/lb, and Btu/gallon for ranges of fuel oils.

1-6. COMBUSTION OF COAL

The fundamentals of coal combustion are illustrated in figure 1-5 which represents hand-fired grate burning. A uniform fuel bed eight inches thick is maintained on the grate. About 50 percent of the air required for combustion enters from below the grate and passes through a layer of ash. The oxygen in this air is consumed while passing through the first few inches of burning fixed carbon. This is called the oxidizing zone. Heat from burning the fixed carbon rises and drives moisture and volatile matter from the raw coal in the oxygen-deficient reducing zone at the top of the bed. The remaining fixed carbon from the top of the bed later burns in the bottom of the bed as additional raw coal is added to the top. Volatile matter in the vapor form and carbon monoxide just above the bed must be fully mixed with overfire air to complete the combustion process. At low firing rates it is important to minimize the amount of overfire air to prevent cooling of the volatile matter resulting in incomplete combustion and soot formation. At intermediate and high firing rates the ability to fully mix volatile matter, carbon monoxide, and overfire air determines the practical excess air levels that can be maintained and completeness of combustion. The rate of combustion is controlled by the underfire combustion air. The efficiency of combustion is determined by the effective turbulent use of overfire combustion air. Stokers may use fans, ducts, air compartments, modulating air dampers, cinder reinjection systems, coal feeders, and moving or vibrating grates to provide better control of the firing rate and efficiency of the coal combustion. In some stokers, a portion of the coal may be burned in suspension before it falls onto the grate. In underfeed stokers, the raw coal is delivered from below the burning coal. Pulverized coal firing systems utilize pulverizers to grind coal to a fine dust. This dust is conveyed by primary combustion air to a burner which serves to ignite the coal and mix additional secondary combustion air with the stream of primary air and coal. The pulverized coal is completely burned in suspension. The principles of coal combustion remain the same for any of these variations. Moisture and volatile matter must be driven off before the fixed carbon

can be burned and combustion air must be effectively mixed with the volatile vapors to efficiently complete combustion.

1-7. COMBUSTION OF OIL

The combustion of fuel oil occurs after the liquid oil is vaporized. The time required for combustion is initially dependent upon the ability of the burner to atomize the oil into fine droplets and provide heat to vaporize the oil. The vapor is then ignited and turbulently mixed with combustion air to stabilize ignition in an ignition zone. The heavy hydrocarbons crack, as described in paragraph 1-9, to give the oil flame its yellow color. The burner must supply additional air to mix with the remaining fuel with adequate time, temperature and turbulence for complete combustion. Careful control and adjustment of the flow of air, oil, and atomizing steam/air are needed to achieve maximum efficiency at all boiler loads.

1-8. COMBUSTION OF NATURAL GAS

Natural gas consists mainly of the simple hydrocarbons methane and ethane and is the easiest fuel to burn, although it can also be the most dangerous. Given the proper time, temperature, turbulence and excess air, gas can sometimes burn without a visible flame or with a blue flame. If some of the hydrocarbons crack as described in paragraph 1-9, a yellow flame will be present. One danger of natural gas combustion is that carbon monoxide, which is poisonous in very low concentrations, may be produced if there is insufficient air or insufficient mixing. For safety and efficiency reasons, incomplete combustion should be avoided by proper control of fuel and air. There is a range of air-gas mixtures which burn violently and explosively. This range varies between 8 and 13 percent gas by volume, depending upon the particular hydrocarbon. Leaner mixtures, 0 to 7 percent, do not explode or burn, while richer mixtures typical of the ignition zone in the combustion process, burn more slowly and do not explode. If a rich concentration of vapor exists, however, it will gradually diffuse into the air and will at some time be within the explosive range. If this mixture comes in contact with a spark or open flame an explosion can occur. In order to prevent buildup of such concentrations, safety shut-off valves are installed on natural gas and oil combustion systems and are very important. Purging of the boiler setting both before and after combustion of any fuel is also extremely important in the prevention of explosions.

1-9. SOOT AND SMOKE

Understanding the causes of soot and smoke is the first step in their prevention.

- a. **Soot.** Soot is unburned carbon from the fuel. The

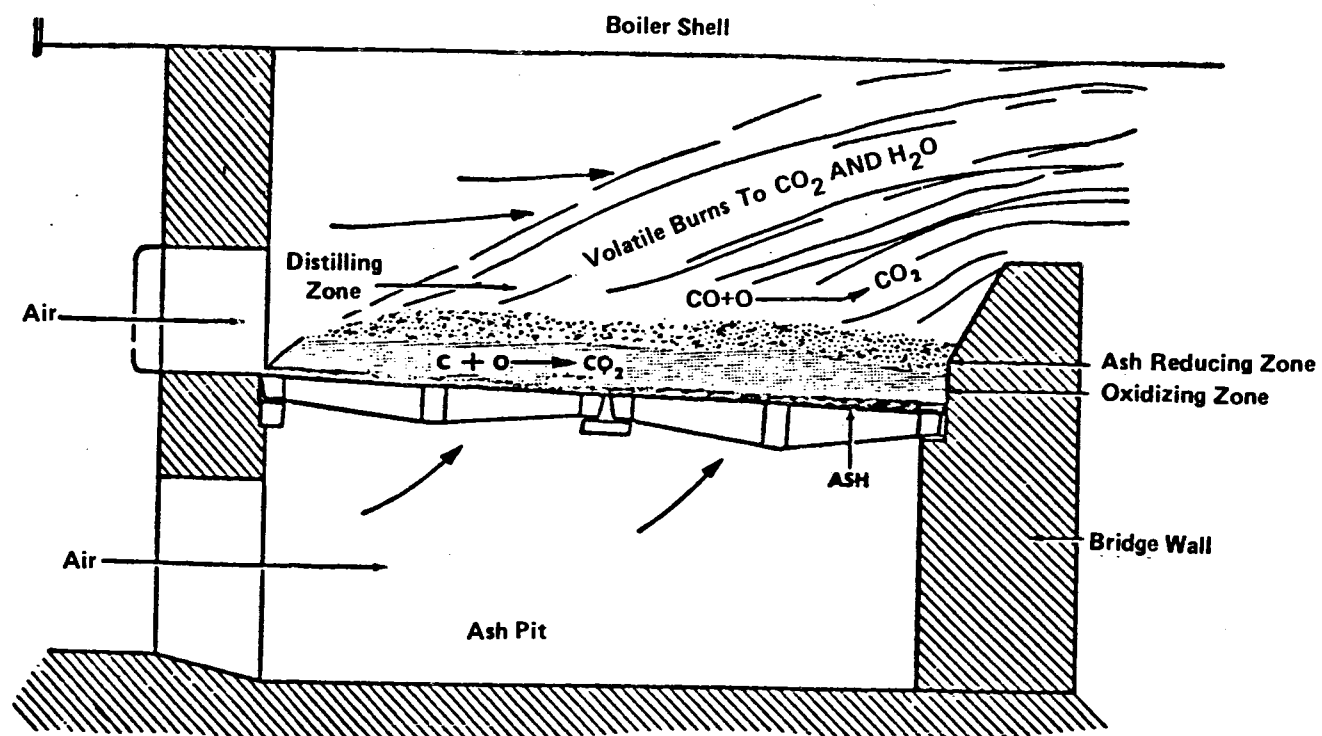


FIGURE 1-5. COMBUSTION OF COAL

finely divided soot particles give flue gases a black color when present. In the refining oil, heavy hydrocarbons are cracked into simpler hydrocarbons, carbon, and hydrogen. This cracking (thermal decomposition) process is also one of the reactions which occur when a fuel is burned. For example, if methane gas is slowly heated and mixed with air, the gas burns with no visible flame or a blue flame. The methane is oxidized without cracking and several intermediate carbon/hydrogen/oxygen compounds are formed. However, if the methane is heated quickly, the gas is cracked into hydrogen and carbon. The carbon particles glow when burnt, giving off a yellow color. If this yellow flame comes in contact with a boiler tube, the carbon in the flame can be cooled and deposited on the tube as soot. If a flame containing elemental carbon is not given enough time and proper temperature for combustion, soot will form as the carbon cools. For example, when a boiler is fired beyond its rated capacity, it is required to burn more fuel in the same furnace. When this happens, the time available for combustion is shortened, and may become so short that complete combustion is not possible. Another potential time for soot to form is during the start-up of a cold boiler or while operating at low-fire. Under these conditions, enough heat may be transferred from the flame to cool it below its ignition temperature and cause the formation of soot.

b. Smoke. Smoke seen in boiler flue gas results from the presence of soot and ash from the combustion process. It is difficult to make natural gas fire smoke, but oil and coal, if not properly controlled, will smoke readily due to the more rapid cracking of their complex hydrocarbons. While the heat loss from unburned carbon may not be significant (tenths of a percent of efficiency), smoke formation indicates a waste of fuel and a possible soot buildup in the furnace and convection passes. Such buildups can result in large efficiency losses associated with reduced heat transfer and higher boiler exit gas temperatures. Smoke of colors other than black is less noticeable but can be just as wasteful. Blue smoke from an oil-fired boiler indicates that a portion of the oil is not being cracked while white smoke generally indicates high excess air levels. In either case, a major burner problem is indicated. It is common practice when adjusting the combustion process to start with high excess air and white smoke. At some lower range of excess air no smoke will be visible and finally, at still lower excess air levels, black smoke will occur. Coal-fired often generate white smoke related to the ash in the coal.

c. Stack Opacity. Operating with a minimum practical level of smoke as measured by stack opacity indicates a generally well run boiler plant. Stack opacity is measured on a 0 percent (clear) to 100 percent (completely opaque) scale. A practical level of smoke would be less than local

opacity limits (typically 10 to 20 percent) and based upon obtaining optimum boiler efficiency. A slight decrease in opacity may not be acceptable if it must be obtained with a large increase in excess air. When burning coal, the amount of carbon in the stoker and collection hoppers should be considered when reviewing excess air and opacity levels.

1-10. FLUE GAS ANALYSIS AND TEMPERATURE

The performance of a burner and boiler can largely be determined by analysis and temperature of the flue gas. The flue gas temperature at the boiler, economizer, or air heater outlet provides information on boiler cleanliness, firing rate, and efficiency. Flue gas analysis establishes the amount of oxygen, carbon dioxide, and carbon monoxide in the flue gas. This analysis is generally on a dry basis by volume since the water vapor is condensed before analysis. Given the type of fuel being burned and the oxygen or carbon dioxide level, tables 1-4 through 1-8 can be used to determine the percent of excess air in the flue gas for natural gas, No. 2 oil, No. 6 oil, and coal. Gas absorption analyzers like the Orsat and "FYRITE" CO₂ bottle are occasionally used to monitor system efficiency. These two analyzers are adequate for monitoring steady boiler loads if care is used in obtaining samples and maintaining the analyzer. Continuous analyzers are also available using either a fuel cell or zirconium oxide element to monitor oxygen levels. The technology of these analyzers is advancing rapidly and many of the current models are accurate, easy to maintain, and will provide a continuous record of the flue gas analysis. By using a continuous monitor an operator can immediately observe the results of firing rate changes and can see how the oxygen level changes at different points in the flue. Monitoring different points in a flue can help to determine if the boiler setting is leaking. Figure 1-6 illustrates an efficiency monitor which includes an oxygen analyzer, carbon monoxide analyzer, smoke tester, thermocouple, and digital readouts for the various measurements. Combustibles analyzers are also available and are particularly valuable for natural gas fired boilers. Smoke density or opacity monitors are commonly used for tuning and monitoring boiler operation.

1-11. COMBUSTION EFFICIENCY

Boiler combustion efficiency can be determined if proper information is available on fuel analysis, flue gas analysis, combustion air temperature, and stack temperature. The loss of heat in the flue gas, on a percentage basis, is subtracted from 100 percent to provide the percentage combustion efficiency. The heat lost with the flue gas is

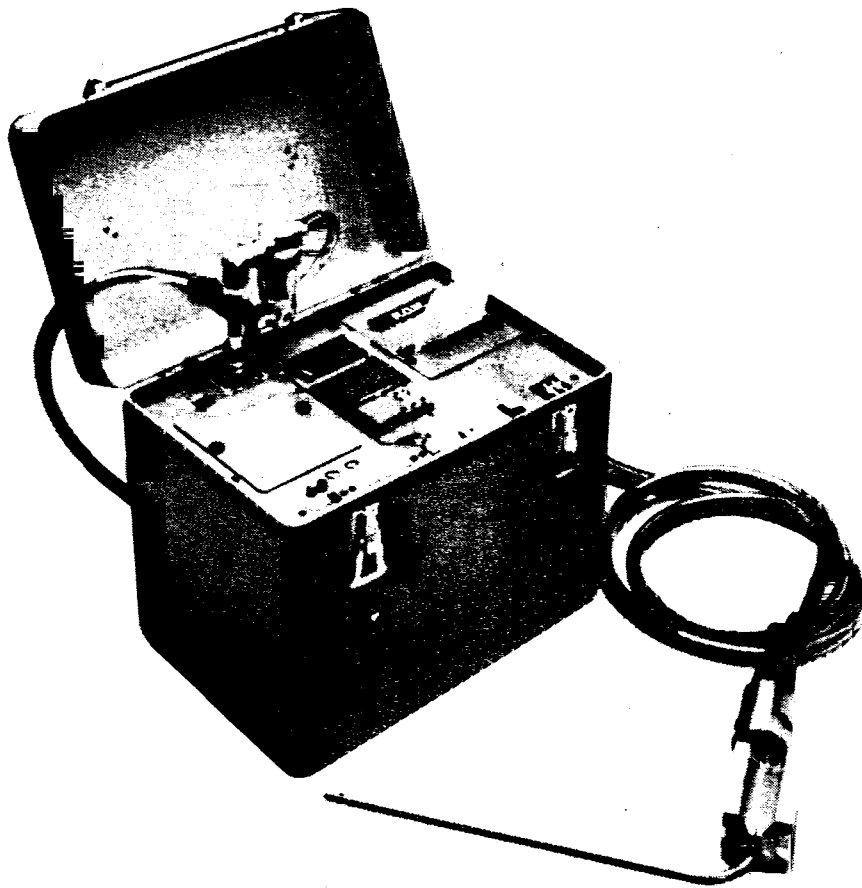


FIGURE 1-6. COMBUSTION EFFICIENCY MONITOR

determined by its temperature and chemical analysis. The amounts of excess air and water vapor are most important in determining their loss. Water is contained in the flue gas in its vapor state. Each pound of water vapor requires 970 Btu of the energy supplied to the boiler to maintain it in its vapor state. In addition to this 970 Btu/lb, water vapor also contains 80% more energy per pound than the other flue gas constituents. The effect of this water vapor on boiler efficiency can be illustrated by comparing a natural gas fired boiler to one fired by oil. For identical levels of excess air, combustion air temperature and stack temperature, the natural gas fired boiler will have a lower combustion efficiency than the oil fired boiler. This happens because natural gas contains more hydrogen than oil and thus has more water in the flue gas. Using table 1-4 and 1-6, at 15% excess air, 70°F combustion air temperature, and 530°F stack temperature, the combustion efficiency of a natural gas fired boiler is 78.9° as compared with 83.4° for a No. 6 oil-fired boiler. Tables 1-4 through 1-8 are Combustion Efficiency Tables for natural gas, No. 2 oil, No. 6 oil, coal with 3.5° moisture, and coal with 9.0° moisture respectively. The combustion efficiency for No. 4 oil may be considered the average of the combustion efficiencies for No. 2 oil and No. 6 oil. Expanded versions of the tables presented here may be found in the Boiler Efficiency Institute book entitled "Boiler Efficiency Improvement."

1-12. BOILER EFFICIENCY

Boiler efficiency is simply defined as the amount of energy in the steam or hot water leaving the boiler (E_{out} , Btu/lb x lb/hr = Btu/hr) minus the energy in the feedwater (E_{fw} , Btu/lb x lb/hr) divided by the amount of energy in the fuel used (E_{fuel} , Btu/lb x lb/hr).

$$\text{Boiler Efficiency} = \frac{(E_{out} - E_{fw})}{E_{fuel}}$$

Boiler efficiency must always be less than combustion efficiency. Typical boiler efficiencies range from 75 to 85 percent. The main boiler loss is the heat lost in the flue gas as discussed in the previous paragraph. Other energy losses are associated with heat radiated from the boiler casing, heat carried away by the blowdown water, and heat lost because of incomplete combustion. To achieve maximum boiler efficiency the operator must:

- Minimize excess air to reduce stack losses.
- Clean the gas side and water side of the boiler tubes to ensure maximum absorption of heat and reduced stack temperatures.
- Minimize blowdown to reduce blowdown losses.
- Perform maintenance on burners and controls to minimize unburned fuel.

A more detailed discussion of boiler efficiency is provided

in chapter 3.

1-13. CENTRAL BOILER PLANT EFFICIENCY

The amount of energy in the steam or hot water leaving the plant (E_{out} of plant, Btu/lb x lb/hr) minus the amount of energy in the condensate or hot water return (E_{return} , Btu/lb x lb/hr), divided by the amount of energy in the fuel (E_{fuel} , Btu/lb x lb/hr) used to produce that steam or hot water is the Central Boiler Plant efficiency.

$$\text{Plant Efficiency} = \frac{(E_{out \text{ of plant}} - E_{return})}{E_{fuel}}$$

Boiler selection, deaerator control, steam trap maintenance, use of steam driven auxiliaries, and plant building energy conservation are all important contributing elements to boiler plant efficiency. Energy losses and use should be controlled to keep plant efficiency as close as possible to boiler efficiency. The use of steam driven auxiliaries reduces the amount of energy sent out of the central plant and steam losses can result if the exhaust steam cannot be used in the deaerator or building heating system. Distribution system losses should also be monitored and reported from the Central Boiler Plant. While strictly speaking they are not a part of central plant efficiency, distribution system losses greatly affect the efficiency of the system. Any makeup water required to replace distribution losses must be heated to the feedwater temperature. This requires additional steam to be generated by the boilers, thus using additional fuel and lowering plant efficiency. More information is provided in chapter 3.

Table 1-4. Combustion Efficiency for Natural Gas

% Excess Air	% O ₂	% CO ₂	Percent Combustion Efficiency											
			Flue Gas Temperature Minus Combustion Air Temperature, Deg F						Percent Combustion Efficiency					
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	11.8	86.1	85.3	84.5	83.6	82.8	81.9	81.0	80.1	79.3	78.4	77.5	76.6
4.5	1.0	11.2	86.0	85.1	84.2	83.4	82.5	81.6	80.7	79.8	78.9	77.9	77.0	76.1
9.5	2.0	10.7	85.8	84.9	84.0	83.1	82.2	81.2	80.3	79.4	78.4	77.5	76.5	75.5
12.1	2.5	10.4	85.7	84.8	83.9	83.0	82.0	81.1	80.1	79.1	78.2	77.2	76.2	75.2
15.0	3.0	10.1	85.7	84.7	83.8	82.8	81.8	80.9	79.9	78.9	77.9	76.9	75.9	74.9
18.0	3.5	9.8	85.6	84.6	83.6	82.6	81.7	80.7	79.7	78.7	77.6	76.6	75.6	74.6
21.1	4.0	9.6	85.5	84.5	83.5	82.5	81.5	80.5	79.4	78.4	77.4	76.3	75.3	74.2
24.5	4.5	9.3	85.4	84.3	83.3	82.3	81.3	80.2	79.2	78.1	77.1	76.0	74.9	73.8
28.1	5.0	9.0	85.2	84.2	83.2	82.1	81.1	80.0	78.9	77.8	76.7	75.6	74.5	73.4
31.9	5.5	8.7	85.1	84.1	83.0	81.9	80.8	79.7	78.6	77.5	76.4	75.3	74.1	73.0
35.9	6.0	8.4	85.0	83.9	82.8	81.7	80.6	79.5	78.3	77.2	76.0	74.9	73.7	72.5
40.3	6.5	8.2	84.9	83.7	82.6	81.5	80.3	79.2	78.0	76.8	75.6	74.5	73.3	72.0
44.9	7.0	7.9	84.7	83.5	82.4	81.2	80.0	78.8	77.6	76.4	75.2	74.0	72.8	71.5
49.9	7.5	7.6	84.5	83.4	82.2	80.9	79.7	78.5	77.3	76.0	74.8	73.5	72.2	71.0
55.3	8.0	7.3	84.4	83.1	81.9	80.7	79.4	78.1	76.9	75.6	74.3	73.0	71.7	70.4
67.3	9.0	6.7	84.0	82.7	81.4	80.0	78.7	77.3	76.0	74.6	73.2	71.8	70.4	69.0
81.6	10.0	6.2	83.5	82.1	80.7	79.3	77.8	76.4	74.9	73.4	71.9	70.4	68.9	67.4
98.7	11.0	5.6	83.0	81.5	79.9	78.3	76.8	75.2	73.6	72.0	70.4	68.8	67.1	65.5
119.7	12.0	5.1	82.3	80.6	78.9	77.2	75.5	73.8	72.0	70.3	68.5	66.7	64.9	63.1
145.8	13.0	4.5	81.5	79.6	77.7	75.8	73.9	72.0	70.1	68.1	66.2	64.2	62.2	60.2
179.5	14.0	3.9	80.4	78.3	76.2	74.0	71.9	69.7	67.5	65.3	63.1	60.9	58.7	56.4
224.3	15.0	3.4	79.0	76.6	74.1	71.7	69.2	66.7	64.2	61.7	59.1	56.5	54.0	51.4

This table is based on the following fuel analysis (% by weight): carbon-70.8%, hydrogen-23.4%, nitrogen-3.8%, oxygen-1.2%, carbon dioxide-.8%. The higher heating value is 21,700 Btu/lb.

Table 1-5. Combustion Efficiency for Number 2 Oil

% Excess Air	% O ₂	% CO ₂	Percent Combustion Efficiency											
			Flue Gas Temperature						Minus Combustion Air Temperature, Deg F					
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	15.6	90.4	89.6	88.8	88.0	87.1	86.3	85.5	84.7	83.8	83.0	82.1	81.3
4.7	1.0	14.9	90.2	89.4	88.6	87.7	86.9	86.0	85.2	84.3	83.4	82.5	81.6	80.7
9.9	2.0	14.1	90.1	89.2	88.3	87.4	86.6	85.7	84.8	83.9	82.9	82.0	81.1	80.2
12.6	2.5	13.8	90.0	89.1	88.2	87.3	86.4	85.5	84.6	83.6	82.7	81.8	80.8	79.9
15.6	3.0	13.4	89.9	89.0	88.1	87.1	86.2	85.3	84.3	83.4	82.4	81.5	80.5	79.5
18.7	3.5	13.0	89.8	88.9	87.9	87.0	86.0	85.1	84.1	83.1	82.2	81.2	80.2	79.2
22.0	4.0	12.6	89.7	88.7	87.8	86.8	85.8	84.9	83.9	82.9	81.9	80.9	79.8	78.8
25.5	4.5	12.3	89.6	88.6	87.6	86.6	85.6	84.6	83.6	82.6	81.6	80.5	79.5	78.4
29.2	5.0	11.9	89.5	88.5	87.4	86.4	85.4	84.4	83.3	82.3	81.2	80.2	79.1	78.0
33.2	5.5	11.5	89.3	88.3	87.3	86.2	85.2	84.1	83.0	82.0	80.9	79.8	78.7	77.6
37.4	6.0	11.2	89.2	88.1	87.1	86.0	84.9	83.8	82.7	81.6	80.5	79.4	78.3	77.1
41.9	6.5	10.8	89.1	88.0	86.9	85.8	84.6	83.5	82.4	81.3	80.1	79.0	77.8	76.6
46.8	7.0	10.4	88.9	87.8	86.6	85.5	84.4	83.2	82.0	80.9	79.7	78.5	77.3	76.1
52.0	7.5	10.0	88.7	87.6	86.4	85.2	84.1	82.9	81.7	80.4	79.2	78.0	76.7	75.5
57.6	8.0	9.7	88.6	87.4	86.2	84.9	83.7	82.5	81.2	80.0	78.7	77.5	76.2	74.9
70.2	9.0	8.9	88.2	86.9	85.6	84.3	83.0	81.6	80.3	79.0	77.6	76.2	74.9	73.5
85.0	10.0	8.2	87.7	86.3	84.9	83.5	82.1	80.6	79.2	77.8	76.3	74.8	73.3	71.8
102.9	11.0	7.4	87.1	85.6	84.1	82.6	81.0	79.5	77.9	76.3	74.7	73.1	71.5	69.9
124.7	12.0	6.7	86.5	84.8	83.1	81.4	79.7	78.0	76.3	74.5	72.8	71.0	69.2	67.4
152.0	13.0	6.0	85.6	83.7	81.9	80.0	78.1	76.2	74.3	72.3	70.4	68.4	66.4	64.4
187.0	14.0	5.2	84.5	82.4	80.3	78.2	76.0	73.8	71.7	69.5	67.3	65.0	62.8	60.5
233.7	15.0	4.5	83.0	80.6	78.2	75.7	73.2	70.7	68.2	65.7	63.1	60.6	58.0	55.4

This table is based on the following fuel analysis (% by weight): carbon-86.7%, hydrogen-12.4%, nitrogen-.1%, sulfur-.8%.
The higher heating value is 19,500 Btu/lb.

Table 1-6. Combustion Efficiency for Number 6 Oil

% Excess Air	% O ₂	% CO ₂	Percent Combustion Efficiency											
			Flue Gas Temperature						Minus Combustion Air Temperature, Deg F					
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	16.5	91.2	90.4	89.6	88.8	87.9	87.1	86.3	85.4	84.6	83.7	82.9	82.0
4.7	1.0	15.7	91.0	90.2	89.4	88.5	87.7	86.8	85.9	85.1	84.2	83.3	82.4	81.5
10.0	2.0	14.9	90.9	90.0	89.1	88.2	87.3	86.4	85.5	84.6	83.7	82.8	81.8	80.9
12.8	2.5	14.5	90.8	89.9	89.0	88.1	87.2	86.3	85.3	84.4	83.4	82.5	81.5	80.6
15.8	3.0	14.1	90.7	89.8	88.9	87.9	87.0	86.1	85.1	84.1	83.2	82.2	81.2	80.2
18.9	3.5	13.8	90.6	89.7	88.7	87.8	86.8	85.8	84.9	83.9	82.9	81.9	80.9	79.9
22.3	4.0	13.4	90.5	89.5	88.6	87.6	86.6	85.6	84.6	83.6	82.6	81.6	80.5	79.5
25.8	4.5	13.0	90.4	89.4	88.4	87.4	86.4	85.4	84.3	83.3	82.3	81.2	80.2	79.1
29.6	5.0	12.6	90.3	89.2	88.2	87.2	86.2	85.1	84.1	83.0	81.9	80.9	79.8	78.7
33.6	5.5	12.2	90.1	89.1	88.0	87.0	85.9	84.8	83.8	82.7	81.6	80.5	79.4	78.2
37.9	6.0	11.8	90.0	88.9	87.8	86.8	85.7	84.6	83.4	82.3	81.2	80.0	78.9	77.7
42.4	6.5	11.4	89.8	88.7	87.6	86.5	85.4	84.2	83.1	81.9	80.8	79.6	78.4	77.2
47.3	7.0	11.0	89.7	88.6	87.4	86.3	85.1	83.9	82.7	81.5	80.3	79.1	77.9	76.7
52.6	7.5	10.6	89.5	88.3	87.2	86.0	84.8	83.6	82.3	81.1	79.9	78.6	77.4	76.1
58.2	8.0	10.2	89.3	88.1	86.9	85.7	84.4	83.2	81.9	80.6	79.4	78.1	76.8	75.5
71.0	9.0	9.4	88.9	87.6	86.3	85.0	83.7	82.3	81.0	79.6	78.2	76.8	75.4	74.0
86.0	10.0	8.6	88.5	87.0	85.6	84.2	82.7	81.3	79.8	78.3	76.9	75.4	73.9	72.3
104.1	11.0	7.9	87.9	86.3	84.8	83.2	81.7	80.1	78.5	76.9	75.2	73.6	72.0	70.3
126.1	12.0	7.1	87.2	85.5	83.8	82.1	80.3	78.6	76.8	75.0	73.3	71.5	69.6	67.8
153.7	13.0	6.3	86.3	84.4	82.5	80.6	78.6	76.7	74.7	72.8	70.8	68.8	66.8	64.7
189.1	14.0	5.5	85.2	83.0	80.9	78.7	76.5	74.3	72.1	69.8	67.6	65.3	63.0	60.7
236.4	15.0	4.7	83.7	81.2	78.7	76.2	73.6	71.1	68.5	65.9	63.3	60.7	58.1	55.4

This table is based on the following fuel analysis (% by weight): carbon-88.4%, hydrogen-10.0%, nitrogen-0.9%, sulfur-.7%. The higher heating value is 18,300 Btu/lb.

Table I-7. Combustion Efficiency for Coal, 3.5% Moisture, Bituminous

% Excess Air	% O ₂	% CO ₂	Percent Combustion Efficiency											
			Flue Gas Temperature						Minus Combustion Air Temperature, Deg F					
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	18.4	92.0	91.2	90.3	89.5	88.6	87.7	86.8	85.9	85.0	84.1	83.1	82.2
4.8	1.0	17.6	91.9	91.0	90.1	89.2	88.3	87.3	86.4	85.5	84.5	83.6	82.6	81.6
10.2	2.0	16.7	91.7	90.8	89.8	88.9	87.9	86.9	86.0	85.0	84.0	83.0	82.0	81.0
16.2	3.0	15.8	91.5	90.5	89.5	88.5	87.5	86.5	85.5	84.5	83.4	82.4	81.3	80.3
22.8	4.0	14.9	91.3	90.2	89.2	88.2	87.1	86.0	85.0	83.9	82.8	81.7	80.6	79.5
26.4	4.5	14.5	91.1	90.1	89.0	87.9	86.9	85.8	84.7	83.6	82.4	81.3	80.2	79.0
30.3	5.0	14.0	91.0	89.9	88.8	87.7	86.6	85.5	84.4	83.2	82.1	80.9	79.7	78.6
34.4	5.5	13.6	90.9	89.8	88.6	87.5	86.3	85.2	84.0	82.9	81.7	80.5	79.3	78.1
38.8	6.0	13.2	90.7	89.6	88.4	87.2	86.1	84.9	83.7	82.5	81.3	80.0	78.8	77.6
43.5	6.5	12.7	90.6	89.4	88.2	87.0	85.8	84.5	83.3	82.1	80.8	79.5	78.3	77.0
48.5	7.0	12.3	90.4	89.2	87.9	86.7	85.4	84.2	82.9	81.6	80.3	79.0	77.7	76.4
53.9	7.5	11.9	90.2	88.9	87.7	86.4	85.1	83.8	82.5	81.1	79.8	78.5	77.1	75.7
59.7	8.0	11.4	90.0	88.7	87.4	86.1	84.7	83.4	82.0	80.6	79.2	77.9	76.5	75.0
65.9	8.5	11.0	89.8	88.4	87.1	85.7	84.3	82.9	81.5	80.1	78.6	77.2	75.8	74.3
72.7	9.0	10.5	89.6	88.2	86.7	85.3	83.9	82.4	81.0	79.5	78.0	76.5	75.0	73.5
80.1	9.5	10.1	89.3	87.9	86.4	84.9	83.4	81.9	80.4	78.8	77.3	75.7	74.2	72.6
88.1	10.0	9.7	89.0	87.5	86.0	84.4	82.9	81.3	79.7	78.1	76.5	74.9	73.3	71.6
106.6	11.0	8.8	88.4	86.8	85.1	83.4	81.7	80.0	78.2	76.5	74.7	73.0	71.2	69.4
129.2	12.0	7.9	87.7	85.8	84.0	82.1	80.2	78.3	76.4	74.5	72.6	70.6	68.7	66.7
157.5	13.0	7.0	86.7	84.6	82.6	80.5	78.4	76.3	74.2	72.0	69.9	67.7	65.5	63.3
193.8	14.0	6.1	85.5	83.1	80.8	78.4	76.0	73.6	71.2	68.8	66.4	63.9	61.4	58.9
242.2	15.0	5.3	83.8	81.1	78.4	75.7	72.9	70.1	67.4	64.5	61.7	58.9	56.0	53.1

This table is based on the following fuel analysis (% by weight): ash-5.0%, sulfur-0.92%, hydrogen-5.12%, carbon-77.13%, moisture-3.50%, nitrogen-1.49%, oxygen-6.84%. The proximate analysis is VM-36.14%, FC-55.36%, M-3.5%, ash-5.0%. The higher heating value of this Class II Group 3 bituminous coal is 13,750 Btu/lb.

Table 1-8. Combustion Efficiency for Coal, 9.0% Moisture, Bituminous

% Excess Air	% O ₂	% CO ₂	Percent Combustion Efficiency											
			Flue Gas Temperature						Minus Combustion Air Temperature, Deg F					
			180	220	260	300	340	380	420	460	500	540	580	620
0.0	0.0	18.4	91.0	90.1	89.2	88.3	87.4	86.5	85.6	84.7	83.7	82.8	81.8	80.9
4.8	1.0	17.6	90.8	89.9	89.0	88.1	87.1	86.2	85.2	84.2	83.2	82.3	81.3	80.3
10.2	2.0	16.7	90.7	89.7	88.7	87.7	86.8	85.8	84.8	83.7	82.7	81.7	80.6	79.6
16.2	3.0	15.8	90.5	89.4	88.4	87.4	86.4	85.3	84.3	83.2	82.1	81.1	80.0	78.9
22.8	4.0	14.9	90.2	89.2	88.1	87.0	85.9	84.8	83.7	82.6	81.5	80.3	79.2	78.1
26.4	4.5	14.5	90.1	89.0	87.9	86.8	85.7	84.6	83.4	82.3	81.1	80.0	78.8	77.6
30.3	5.0	14.0	90.0	88.8	87.7	86.6	85.4	84.3	83.1	81.9	80.7	79.6	78.3	77.1
34.4	5.5	13.6	89.8	88.7	87.5	86.3	85.2	84.0	82.8	81.6	80.3	79.1	77.9	76.6
38.8	6.0	13.2	89.7	88.5	87.3	86.1	84.9	83.6	82.4	81.2	79.9	78.7	77.4	76.1
43.5	6.5	12.7	89.5	88.3	87.1	85.8	84.6	83.3	82.0	80.7	79.5	78.2	76.8	75.5
48.5	7.0	12.3	89.3	88.1	86.8	85.5	84.2	82.9	81.6	80.3	79.0	77.6	76.3	74.9
53.9	7.5	11.9	89.1	87.8	86.5	85.2	83.9	82.5	81.2	79.8	78.4	77.1	75.7	74.3
59.7	8.0	11.4	88.9	87.6	86.2	84.9	83.5	82.1	80.7	79.3	77.9	76.4	75.0	73.5
65.9	8.5	11.0	88.7	87.3	85.9	84.5	83.1	81.6	80.2	78.7	77.3	75.8	74.3	72.8
72.7	9.0	10.5	88.5	87.0	85.6	84.1	82.6	81.1	79.6	78.1	76.6	75.1	73.5	71.9
80.1	9.5	10.1	88.2	86.7	85.2	83.7	82.1	80.6	79.0	77.5	75.9	74.3	72.7	71.0
88.1	10.0	9.7	88.0	86.4	84.8	83.2	81.6	80.0	78.4	76.7	75.1	73.4	71.7	70.1
106.6	11.0	8.8	87.3	85.6	83.9	82.1	80.4	78.6	76.9	75.1	73.3	71.5	69.6	67.8
129.2	12.0	7.9	86.5	84.6	82.7	80.8	78.9	77.0	75.0	73.0	71.1	69.1	67.0	65.0
157.5	13.0	7.0	85.6	83.4	81.3	79.2	77.0	74.9	72.7	70.5	68.3	66.1	63.8	61.6
193.8	14.0	6.1	84.3	81.9	79.5	77.1	74.6	72.2	69.7	67.2	64.7	62.2	59.7	57.1
242.2	15.0	5.3	82.6	79.8	77.1	74.3	71.5	68.6	65.8	62.9	60.0	57.1	54.1	51.2

This table is based on the following fuel analysis (% by weight): ash-8.0%, sulfur-1.91%, hydrogen-4.48%, carbon-67.40%, moisture-9.00%, nitrogen-1.31%, oxygen-7.90%. The proximate analysis is VM-33.86%, FC-49.14%, M-9.0%, Ash-8.0%. The higher heating value of this Class II Group 4 bituminous coal is 12,050 Btu/lb.

SECTION III. PRINCIPLES OF STEAM AND HOT WATER GENERATION

1-14. BASIC PRINCIPLES

The generation of steam occurs as a result of two separate processes: combustion, the release of heat by burning fuel, and heat transfer, the absorption of heat into the water. Combustion was discussed in the previous section. A study of the heat transfer process can be made with an elementary boiler as shown in figure 1-7. The boiler system can be represented as a container equipped with an outlet pipe and valve, a pressure gage, and a thermometer immersed in the water. If a fire is built under the unit and water at 32° F is put into the container with the valve left open, the water temperature will rise steadily as the fire burns until a temperature of approximately 212° F is reached. At this time, the temperature will rise no further, but the water will gradually boil off and, if firing is continued long enough, all the water will be evaporated. If the heat content of the fuel source is accurately measured, it can be demonstrated that to raise the temperature from 32° F to the boiling point, the heat input was 180 Btu for each pound of water. It would also be shown that 970 additional Btu for each pound of water is required to boil off all the water. This additional heat is called the latent heat of vaporization and represents the heat required to convert the small volume of liquid into a large volume of steam. With the valve in a closed position and using another batch of water, repeat the process and allow pressure to build up to 100 psig, then throttle the valve so that pressure is maintained at 100 psig. The temperature in the container will now be approximately 338° F. This is called the saturation temperature for 100 psig pressure. The heat input required to raise one pound of water from 32° F up to this saturation temperature is 309 Btu. The energy expended in boiling one pound of water from 338° F at 100 psig is 880.6 Btu. The temperature required to boil the water increases as the pressure increases. The amount of heat put into the liquid to raise it to this boiling point temperature is greater and the latent heat of vaporization is progressively less as the pressure increases. Table 1-9 provides a summary of saturation temperatures, energy in water, energy in steam, and latent heat of vaporization for pressures from zero to 300 psig.

1-15. HEAT TRANSFER

Heat transfer is accomplished by three methods: radiation, conduction, and convection. All three methods are used within a boiler. The heating surface in the furnace area receives heat primarily by radiation. The remaining heating surface in the boiler receives heat by convection from the hot flue gases. Heat received by the heating surface travels through the metal by conduction. Heat is then transferred

from the metal to the water by convection. Each of these methods is discussed in more detail below.

a. Radiation. Radiation is the most important method of heat transfer in the furnace. The amount of heat transfer depends on the area of the heating surfaces and hot surfaces in the furnace, the difference of the fourth powers of temperatures of the flame and heating surfaces, and the nature of the flame. For the same temperatures a coal flame is more radiant than an oil flame and an oil flame is more radiant than a natural gas flame. The same physical laws governing transmission of light also apply to the transfer of radiant heat:

- Heat is transmitted in straight lines
- Heat can be reflected and refracted
- Heat is radiated in all directions

Radiant heat can be transmitted through a vacuum, most gases, some liquids, and a few solids. The solid boiler tubes absorb the radiant heat from the flame and radiate a small portion of that heat back to the furnace.

b. Conduction. In conduction, heat is transferred through a material in which the individual particles stay in the same position. Heat flowing along an iron bar when one end of the bar is held in a fire is a simple example of this process. Conduction occurs when the material, called a conductor, is in physical contact with both the heat source and the point of delivery. Heat flows from the hot end to the cold end of the conductor. It makes no difference if the conductor is straight, crooked, inclined, horizontal, or vertical. The material of which it is made has a great effect, however. Metals conduct heat readily while liquids and gases conduct heat more slowly. Some materials conduct heat very poorly, and are called insulators. Common examples of insulators are asbestos, fiberglass, wood, and some types of plastics. The amount of heat transmitted also varies with the length of the path, the contact area, and the temperature difference.

c. Convection. Transfer of heat by convection can be compared to a bucket brigade in which each man carries the water from a supply point to a tank. In this example the medium is represented by the men and the heat is represented by the water. In convection, the gas or liquid medium receives heat from the source, expands, and is pushed away by colder, heavier particles of the medium. The fluid which receives heat then transfers the heat to a new location, losing some heat in the process. It may or may not return to its source to repeat the cycle. Heat transfer by convection normally occurs from a lower to a higher elevation. However, transfer in any direction may take place if an external force, such as fans, pumps, or a pressure drop, is applied.

d. Gas Flow Considerations. In most boilers, a large

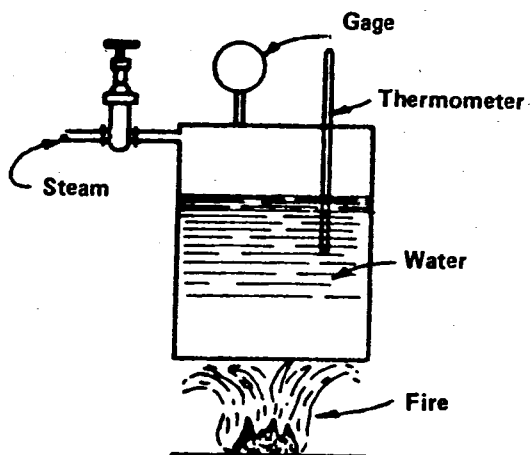


FIGURE 1-7. ELEMENTARY BOILER

Table 1-9. Water/Steam Characteristics

Pressure (psig)	Saturation Temp (°F)	Energy in Water (Btu/lb)	Energy in Steam (Btu/lb)	Latent Heat of Vaporization (Btu/lb)
0	32*	0	-	-
0	60*	28	-	-
0	212	180	1150	970
15	250	218	1164	946
30	274	243	1172	929
40	287	256	1176	920
50	298	267	1179	912
60	307	277	1182	905
70	316	286	1184	898
80	324	294	1186	892
90	331	302	1188	886
100	338	309	1190	881
110	344	316	1191	875
120	350	322	1192	870
130	356	328	1193	865
140	361	333	1195	862
150	366	339	1196	857
200	388	362	1199	837
250	406	382	1202	820
300	422	399	1203	804

* 32°F and 60°F are not saturation temperatures of water at 0 psig.

part of the absorbed heat is given up by hot flue gases which sweep over the heat-absorbing surfaces. Heat transfer takes place by convection. The quantity of heat transferred can be varied by controlling the temperature or quantity of the flue gases. Usually both are controlled. The ability of materials to resist the damaging effects of high temperatures is the limiting factor in the first case, and the force available for causing flow through the boiler is the limiting factor in the second. Boiler draft loss or resistance to flow is the force or pressure drop required for gases to flow through a boiler. Draft loss is commonly called "draft" and may be supplied by a chimney, forced draft fan, or induced draft fan. Draft, which is measured in inches of water, depends primarily on velocity and density of the flowing gases, and cross-sectional area and length of the gas passage. Draft loss increases with the square of the velocity and directly with the length of the passage. Thus, force required to maintain the proper flow increases by a factor of four when velocity is doubled, and by a factor of two when the passage length is doubled. It is important to keep velocity at a minimum, consistent with the requirements of good convective heat transfer, if the maximum output of a boiler installation is to be attained. The cross-sectional area, baffle arrangement, and length of the gas passage are usually fixed. If gas passages are kept free of soot and ash accumulation, gas velocity and draft loss will depend solely on the quantity of gas flow which in turn depends on the quantity of air supplied to burn the fuel. A minimum air supply consistent with good combustion practice therefore minimizes draft loss and helps to maximize heat transfer and boiler output.

e. Water Circulation Considerations. Water circulates in a steam boiler because the density of water is greater than the density of the water/steam mixture. Reference figure 1-8. Within the boiler the more dense water falls while the less dense mixture rises. Table 1-10 illustrates the relationships of water and steam mixtures at 15 psig, 100 psig, and 400 psig. As noted in table 1-10, the volume ratios become smaller as pressures increase. Natural circulating forces are thus reduced as the operating pressure of a boiler increases, and increased as the percent of steam in the mixture increases. Hot water boilers normally use pumps to force the circulation of water through the boiler, because the density difference between cold and hot water is not large enough to cause natural circulation with the velocities necessary for good heat transfer.

f. Heat Transfer to Boiler Tubes and Water by Convection. Heat transfer by convection depends on the temperature and velocity of the gases on one side of the boiler tube and the velocity of the water on the other side. Heat can be transferred to quiet water at the rate of approximately 2.8 Btu per hour per square foot per degree Fahrenheit of temperature difference (2.8 Btu/hr/ft²/°F).

Increasing the velocity of the water aids convection and increases heat transfer to about 1,500 Btu/hr/ft²/°F. This is due to a very thin film of stagnant water which is in contact with the boiler tube. This can be demonstrated by a simple experiment using a Bunsen burner and a metallic vessel containing boiling water as shown in figure 1-8. Place the lighted burner under the vessel and observe it closely. Note that the flame spreads into a sheet about 1/30 to 1/40 inch from the vessel. Because of its high conductivity, the temperature of the tube is only a few degrees hotter than the water while the temperature of the burner flame is much higher. Therefore, there must be a large temperature drop through the thin film between the flame and the vessel. This principle applies to both the water and gas sides of the vessel. The heat in the boiler tube must be conducted through the thin stagnant film of water before the active convection process begins. Heat transfer can be greatly increased if this film is reduced in thickness, or eliminated completely. Usually, this is accomplished by increasing the flow velocity across the surface and scrubbing the film away. Unfortunately, as was mentioned earlier, increasing velocities increases draft losses and power requirements. The thin film does not affect radiant or conductive heat but only convective heat.

g. Optimizing Heat Transfer. Boiler furnace heat is absorbed by a combination of radiation and convection. The absorbed heat is conducted through the boiler tubes. Water in the boiler tubes is heated by convection. Tubes and other heating surfaces close to the fire which do not have a high rate of gas flowing across them receive practically all their heat by radiation. Heating surfaces close to the furnace and across which the gas flow is high receive heat by both radiation and convection. Surfaces distant from the furnace receive all their heat by convection. Heat transfer can be optimized by controlling excess air, keeping boiler tubes clean, and maintaining optimum gas and water velocities.

(1) Excess Air Control. The rate at which radiant heat is transmitted varies as the fourth power of the absolute or Rankine temperature. (Rankine temperature is based on a scale whose zero represents a complete absence of heat; 0° R is approximately minus 460° F. To convert from Fahrenheit to Rankine, add 460° to Fahrenheit temperature.) The amount of heat transmitted by radiation doubles when the absolute temperature of the radiating source is increased by approximately 19 percent. The rate at which heat is transmitted by radiation from a fuel bed at a temperature of 1050° F (1510° R) can be doubled by increasing the temperature of the refractory wall or bed to 1350° F (1810° R). The rate at which heat is transmitted by radiation from an oil flame can increase by 42 percent by increasing the temperature of the visible flame from 1725° F to 1925° F (2185° R to 2385° R).

Table 1-10. Water/Steam Mixtures

Mixture		Specific Volume, (ft ³ /lb)			Volume Ratio = $\frac{\text{volume of mixture}}{\text{volume of water}}$		
%		Pressure(psig)			Pressure(psig)		
Steam	Water	15	100	400	15	100	400
0.0	100.0	.0170	.0179	.0194	1.00	1.00	1.00
0.1	99.9	.0309	.0217	.0205	1.82	1.21	1.06
0.2	99.8	.0448	.0256	.0216	2.64	1.43	1.11
0.5	99.5	.0863	.0370	.0249	5.08	2.08	1.29
1.0	99.0	.1556	.0562	.0305	9.15	3.15	1.57
100.0	0	13.88	3.88	1.12	816	217	57.8

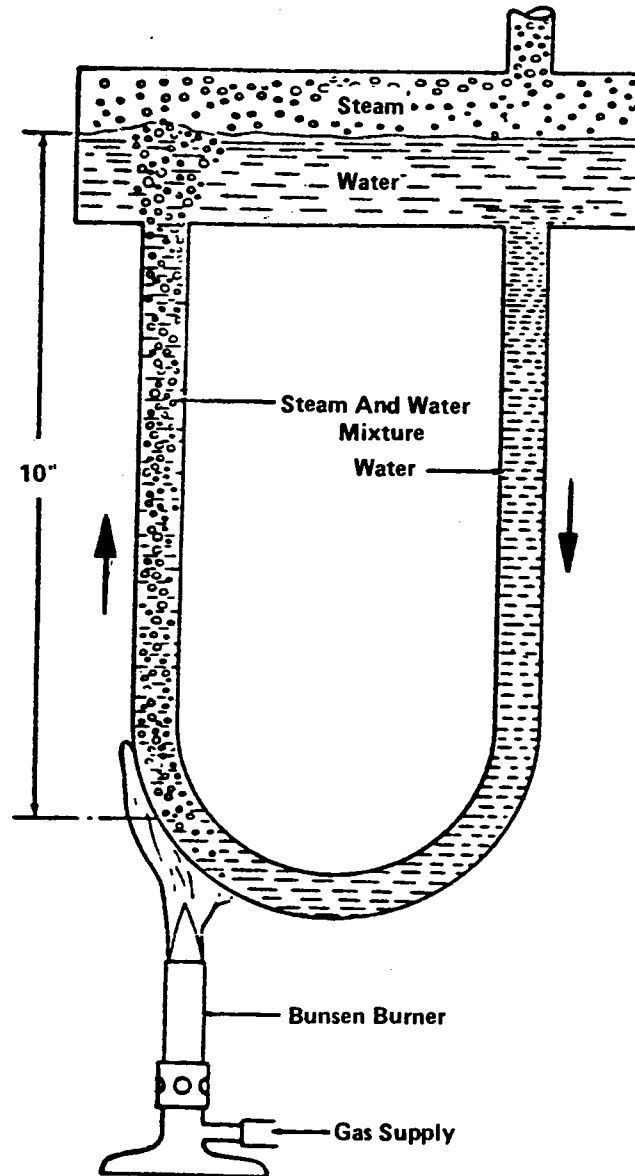


FIGURE 1-8. WATER CIRCULATION

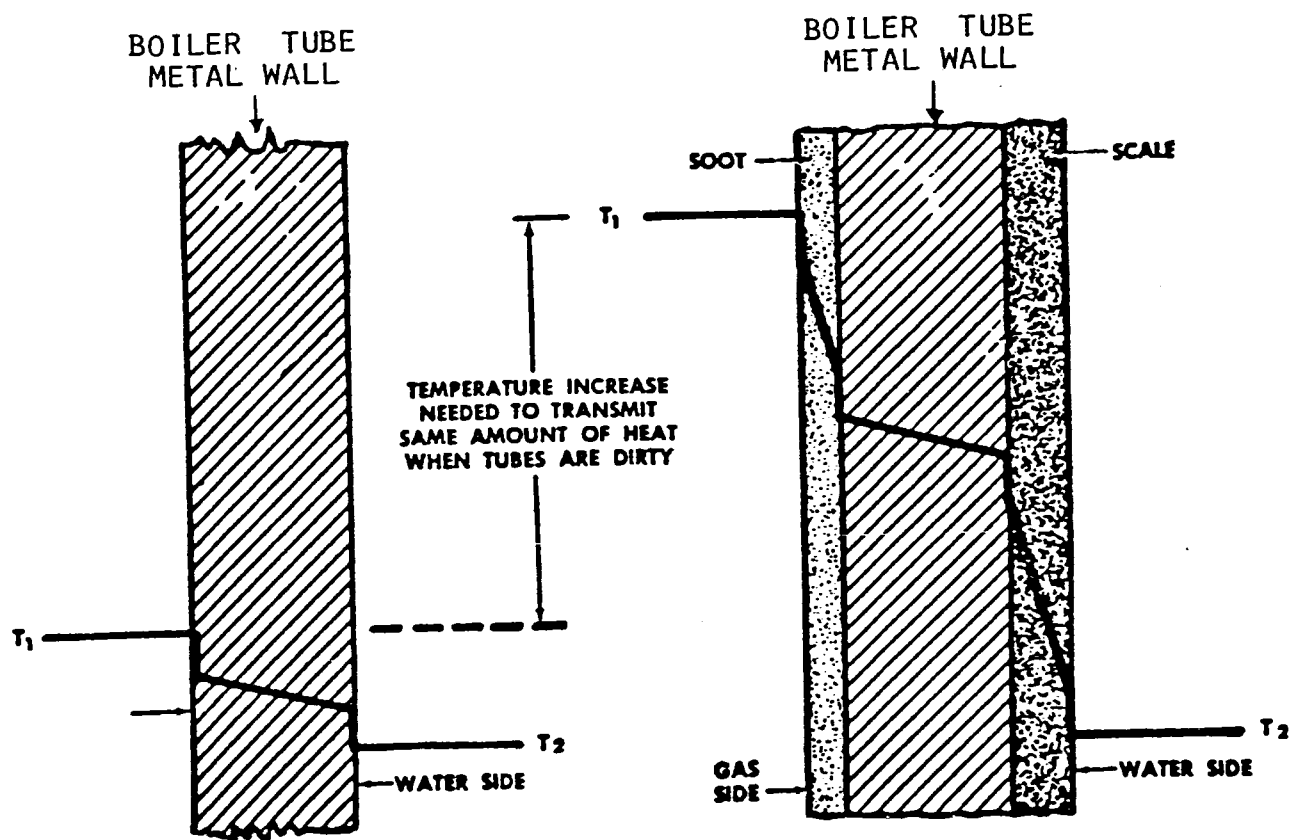


FIGURE 1-9. EFFECT OF SOOT AND SCALE ON HEAT TRANSFER

Reducing the excess air used to combust fuel causes the flame temperature to increase. Maximum flame temperature is normally obtained with approximately 3 to 5 percent excess air. A moderate increase in furnace temperature resulting from an excess air reduction can markedly affect the amount of radiant heat absorbed by the boiler surfaces.

(2) **Maintaining Clean Boiler Tubes.** The amount of heat transferred by conduction depends on the type, thickness, and condition of the conductive material as well as the difference in temperature. Heat is readily conducted through metal, while ash, soot, and scale are poor conductors. Figure 1-9 illustrates the effects of soot and scale. If the heating surfaces become coated with soot, scale, or other material the firing rate of the boiler must be increased to raise gas temperatures and maintain the same amount of heat transfer. Any deposit on either side of the heating surface increases maintenance costs, reduces efficiency, and may cause operator injuries or boiler damage if a tube overheats and ruptures. Reference paragraphs 3-16d and 3-34 for further information.

(3) **Maintaining Gas and Water Passages.** Keeping gas passages free from accumulations of soot and ash and maintaining gas baffles in good repair help to ensure proper gas velocities to all heat transfer surfaces. Keeping water passages free from accumulations of sludge and scale ensures proper water flow and velocity for cooling of the

heat transfer surfaces and generating steam or hot water.

(4) **Maximum Versus Economical Heat Transfer.** Maximum and economical heat transfer are not the same. It is rarely possible to operate a boiler at temperatures high enough to obtain the maximum heat transfer rate because of material limitations, particularly of furnace brickwork. The maximum temperature which can be safely maintained is determined by, among other considerations, the kind of firebrick used, furnace construction (self-supporting, or supported), the quantity and kind of ash in the fuel, furnace size, and the amount and type of cooling of the furnace walls (air cooled or water cooled). It is important to maintain a low gas temperature at the boiler outlet since this results in high boiler efficiency. However, the rate of heat transfer may be relatively low in this area because temperature differences are low. There is a practical limit on the velocity of flue gas based on reasonable fan horsepower requirements and capabilities as discussed in paragraph 1-15d. Water velocity is fixed by boiler design and cleanliness for any particular firing rate. Reduced water velocity at a lower boiler firing rate results in reduced but more economical heat transfer rates. Most of the above factors are determined by the design of the boiler. It is the responsibility of the boiler manufacturer to balance the requirements of maximum heat transfer with economy and produce a cost-effective design.