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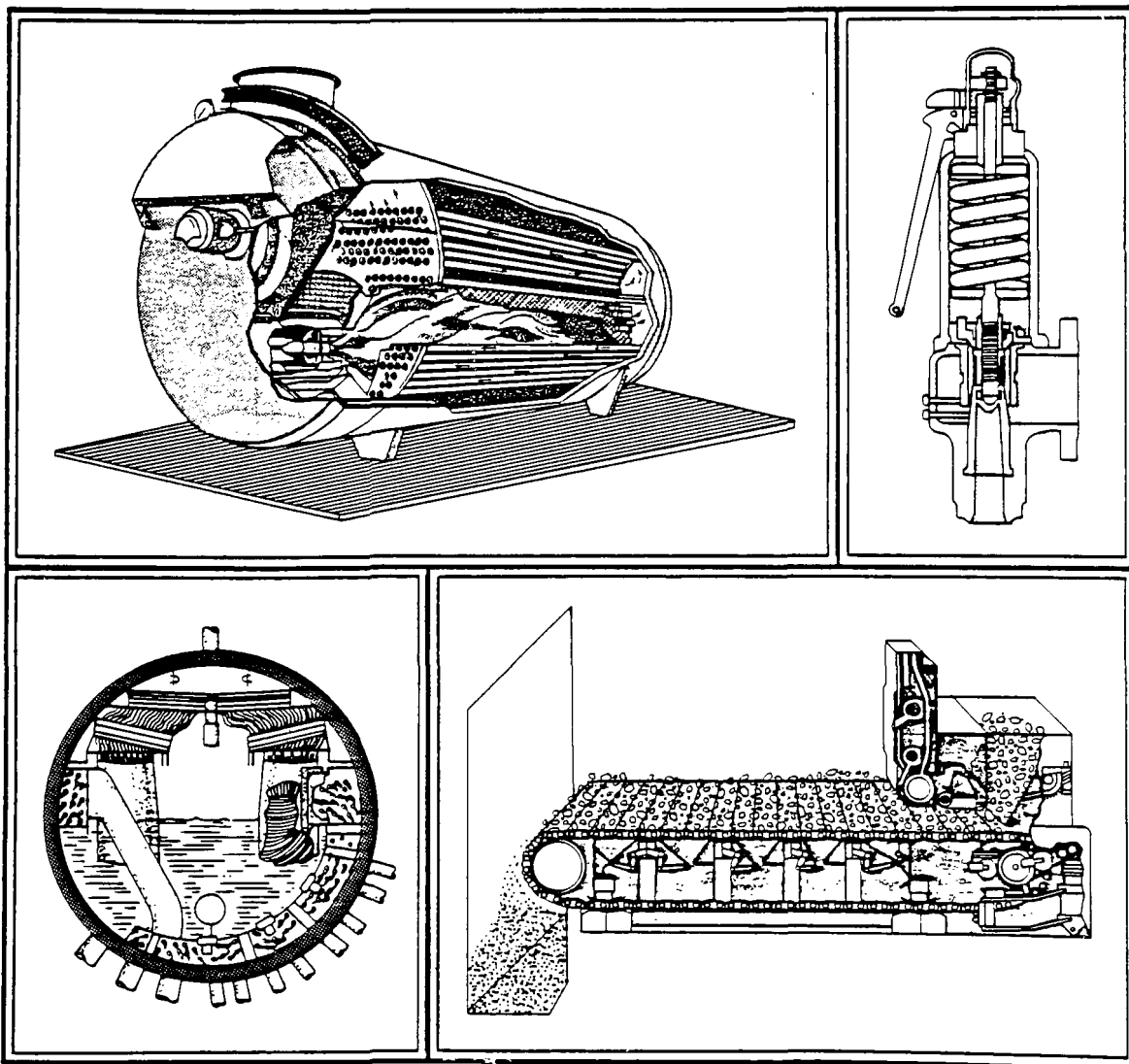


APTI

Course SI:428A

Introduction to Boiler Operation

Self-instructional Guidebook



Air

APTI Course SI:428A Introduction to Boiler Operation

Self-instructional Guidebook

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This document is dedicated to Benjamin Linsky, former professor of the West Virginia University.

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Course Introduction

Description

Designed for engineers and other technical persons responsible for inspecting boilers, this course is an introduction to their operation. The course focuses on the major components of boilers and how boilers operate to produce steam, heat, or electricity. Major topics related to boilers include the following:

- Fire-tube and water-tube designs
- Combustion efficiency
- Supplying air and fuel
- Operation and maintenance
- Steam turbines, condensers, and cooling towers
- Air pollution emissions and control techniques

Course Goal and Objectives

Goal

To familiarize you with boilers—their operation, use of various fuels, common operation and maintenance problems, and components and add-on air pollution control devices which must be inspected.

Objectives

Upon completing this course, you should be able to—

1. briefly describe the overall operation of a boiler,
2. recognize the difference between a fire-tube and a water-tube boiler,
3. calculate boiler efficiency using various figures and tables,
4. briefly describe how air and fuel are introduced into a boiler,
5. recognize various boiler auxiliary equipment and their use, and
6. list three potential air pollution emissions from boilers and at least three control devices used to reduce these emissions.

Prerequisite Skills

- Completion of SI:422 (3rd edition), *Air Pollution Control Orientation*
- Completion of SI:431, *Air Pollution Control Systems for Selected Industries*

It is also recommended that you complete the APTI course series SI:412A, *Baghouse Plan Review*; SI:412B, *Electrostatic Precipitator Plan Review*; and SI:412C, *Wet Scrubber Plan Review*; particularly if you are evaluating plans for the installation of a boiler and associated air pollution control devices.

Requirements for Successful Completion

In order to receive 2.0 Continuing Education Units (CEUs) and a certificate of course completion, you must achieve a final examination grade of at least 70%.

Reading Materials

This text—supplementary reading materials are not required. English units are used in this document to help simplify calculations. Both metric and English units are used in Lesson 6 because the New Source Performance Standards are given in both sets of units. Appendix B contains conversion factors to convert English units into metric units.

Using the Guidebook

This book directs your progress through the course. Each lesson contains a goal and objectives, text, and review exercises. To complete a review exercise, place a piece of paper across the page, covering the questions below the one you are answering. After answering the question, slide the paper down to uncover the next question. The answer for the first question will be given on the right side of the page, separated by a line from the second question, as shown in Figure 1. All answers to review questions will appear below and to the right of their respective questions. The answer will be numbered to match the question. **Please do not write in this book.** Complete each review exercise in the lessons. If you are unsure about a question or answer, review the material preceding the question. Then proceed to the next section.

Review Exercise	
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3. Question ou lor lo nll clllo yllon	2. Answer oh oull

Figure 1. Review exercise format.

Instructions for Completing the Final Examination

Contact the Air Pollution Training Institute if you have any questions about the course or when you are ready to receive a copy of the final examination.

After completing the final exam, return it and the answer sheet to the Air Pollution Training Institute. The final exam grade and course grade will be mailed to you.

Air Pollution Training Institute
Environmental Research Center
MD 20
Research Triangle Park, NC 27711

Lesson 1

Boiler Fundamentals

Lesson Goal and Objectives

Goal

To familiarize you with the fundamental operation of a boiler.

Objectives

Upon completing this lesson, you should be able to—

1. define heat transfer and recognize the difference between three transfer methods,
2. distinguish between a water-tube and a fire-tube boiler,
3. list five tube sections of a boiler and identify their use, and
4. recognize the various ratings and classifications used to identify boilers.

Introduction

A boiler is a closed vessel containing water. Water is changed into steam when heated under controlled conditions. Fuels most commonly used as the heat source for a boiler are natural gas, oil, and coal—referred to as fossil fuels. Other fuels such as wood and solid waste materials are also used. In the boiler, chemical energy contained in the fuel is converted to thermal energy. Thermal energy heats water contained in boiler tubes or the shell to make steam. Steam can then be used for many industrial processes including refining petroleum, manufacturing automobiles, paper, chemicals, and for driving turbines to generate electricity.

Heat Transfer

Every boiler is designed to transfer as much heat as possible (produced from burning fuel) to the water contained in the boiler. Heat is transferred by conduction, radiation, and convection, although the amount of each will vary depending on the boiler design. *Conduction* is heat transfer by direct physical contact between a hot object and a cooler object, or from one part of an object to another part of the same object. Heat flows from the hot object to the cold object until there is no longer a temperature difference between the two objects in contact. The rate at which the heat is transferred will depend on the temperature difference between the two

objects (or parts of the same object) and the heat carrying abilities of the material—called conductivity. Metals are very efficient conductors of heat. Fiborous materials such as fiberglass insulation are inefficient conductors of heat. In a boiler, heat is conducted through the metal in the shell and tubes.

Radiation is the transfer of heat through space from a hot object to a cooler one. Radiation does not require any physical contact between the two objects because radiated heat travels by electromagnetic vibrations. For example, heat is radiated from the hot coals in a camp fire to people sitting around the fire even though the air between the two remains relatively cool. The amount of heat absorbed by radiation depends on the temperature difference and the distance between the two objects, and the nature of the objects. The amount of heat absorbed increases as the temperature difference and distance between two objects decreases or as the temperature difference increases. In the boiler heat is radiated by the flames in the combustion zone, called the firebox. Heat is absorbed by the boiler tubes located in the firebox, and nearby areas of the furnace.

Convection is the transfer of heat by heated fluid. In the case of a boiler, the fluid is the hot gases produced by burning fuel. Heat is transferred from the hot gases to the cold boiler tubes containing water. Convection can be either natural or forced. Natural convection occurs as the heated fluid expands and rises. Cooler portions of the fluid move into the space vacated by the hotter fluid. This mixes the fluid, moving heat from one part of the fluid to another. In forced convection the heated fluid is moved by devices such as a fan or pump.

Boiler Designs

Boilers are either fire-tube or water-tube designs. In fire-tube boilers, hot combustion products pass through the inside of heat exchanger tubes while water, and eventually steam, are contained outside the tubes by an outer shell. In water-tube boilers, hot combustion products pass over tube sections containing water. Water in the tubes is boiled to make steam.

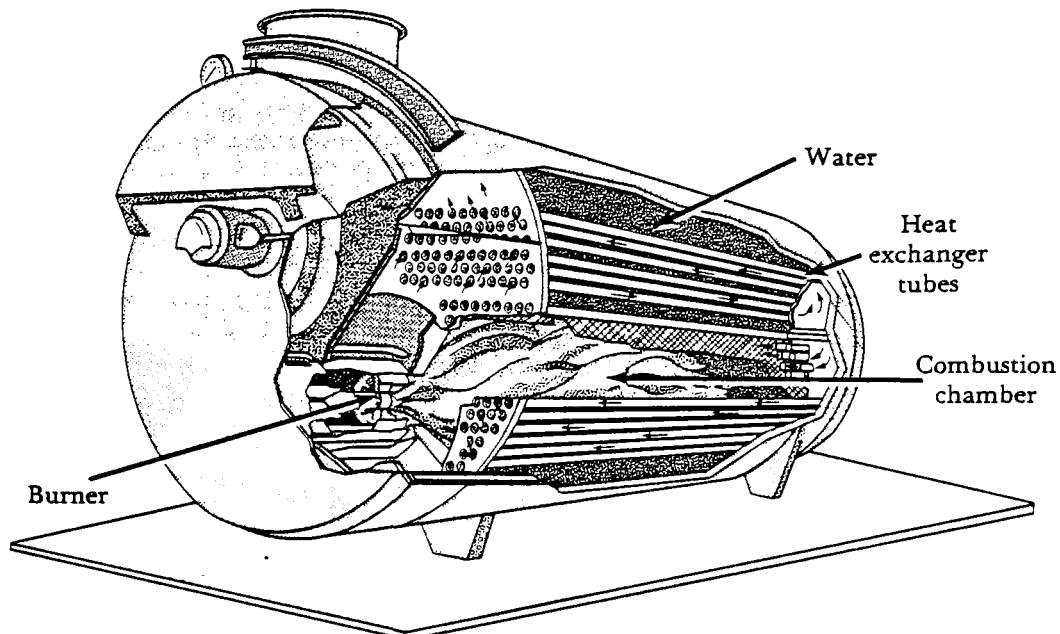
Fire-Tube Boilers

Many small- and medium-sized units are fire-tube boilers. They are usually packaged and sold with burners, blowers, and other equipment all mounted in the same framework. These units generally produce low-pressure steam or heat for small industries, commercial businesses, schools, hospitals, and other institutions.

Fire tubes are straight and connected at their ends by tube sheets. A large body of water, surrounding these tubes and contained in a large shell, boils into steam. The pressures of the steam produced are usually limited to 250 psig because large diameter shells cannot withstand very high pressures.

One common fire-tube boiler is the *horizontal return tubular* (HRT). Figure 1-1 shows a four pass HRT boiler. These boilers are usually designed to burn either natural gas or oil. The first pass occurs as the hot gases generated during combustion pass through the long furnace tube, or combustion chamber. The gases then

move into the tubes at the bottom of the boiler for the second pass. In the third pass, the gases pass through the tube bank directly above the combustion chamber. Finally they reverse direction and pass through the bank of tubes in the top of the furnace and out the stack. HRT boilers vary in size; 4 to 15 ft in diameter and lengths of 6 to 40 ft.



Source: Cleaver Brooks brochure.

Figure 1-1. Typical four pass horizontal return tube boiler.

Another boiler, the *Scotch marine*, has one or more cylindrical furnaces. The furnace is usually a large-diameter tube made of corrugated metal. Some are fired from both ends and called double-ended Scotch boilers. Figure 1-2 shows a conventional Scotch marine boiler with the furnace and tubes contained within the shell. Combustion gases pass through the furnace into the tubes where they heat the surrounding water. Scotch marine boilers are similar to HRT boilers, except that they usually don't have as many tube passes. These units can be designed to burn either gas, oil, or coal. Scotch marine boilers have overall diameters from 3 to 8 ft and lengths of approximately 4 to 20 ft.

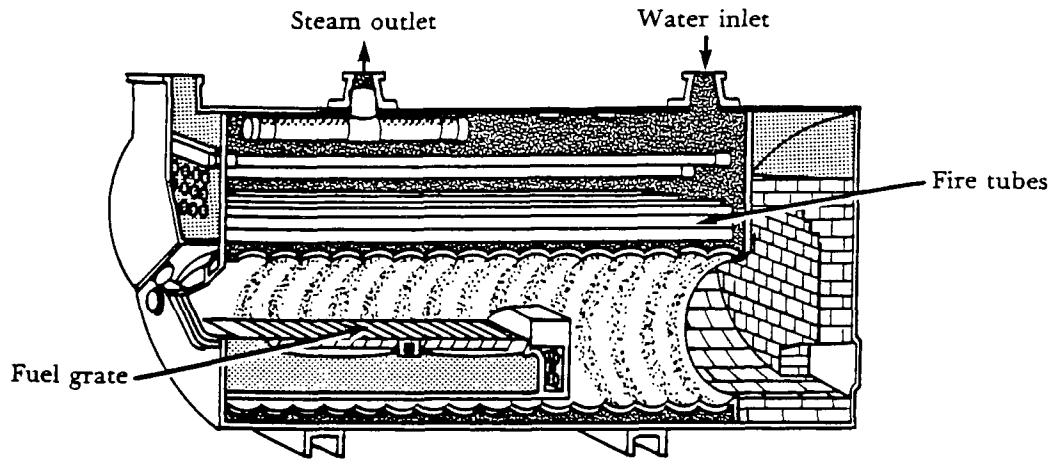


Figure 1-2. Typical Scotch marine boiler.

A variation of a horizontal return tube boiler has a *refractory lined firebox*. In this unit, hot combustion gases pass through tubes located in the upper portion of the furnace. Water contained in the outer shell is heated as the hot gases pass through the tubes (Figure 1-3). These boilers occasionally burn coal but can also burn gas or oil. The sizes of these units are similar to Scotch marine boilers.

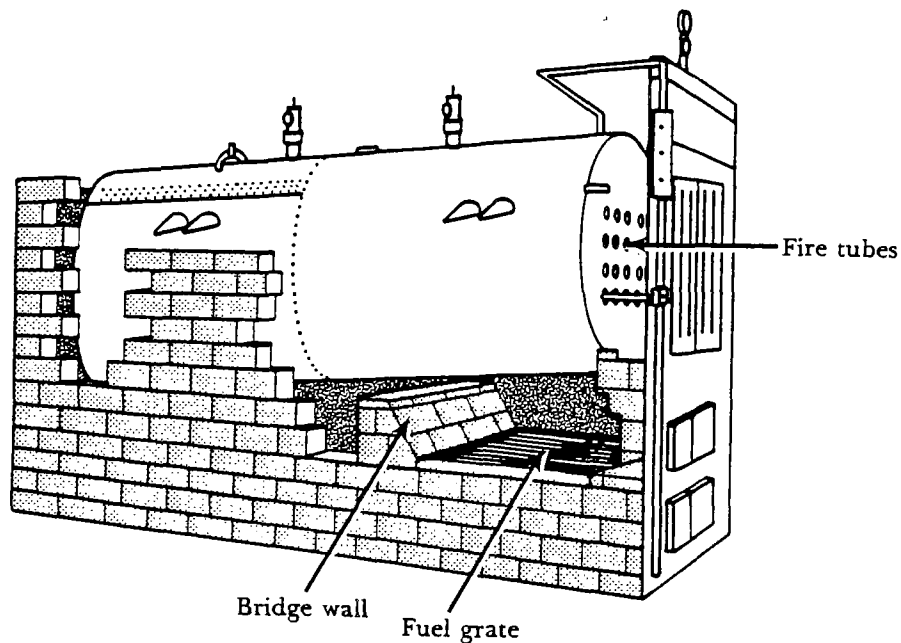


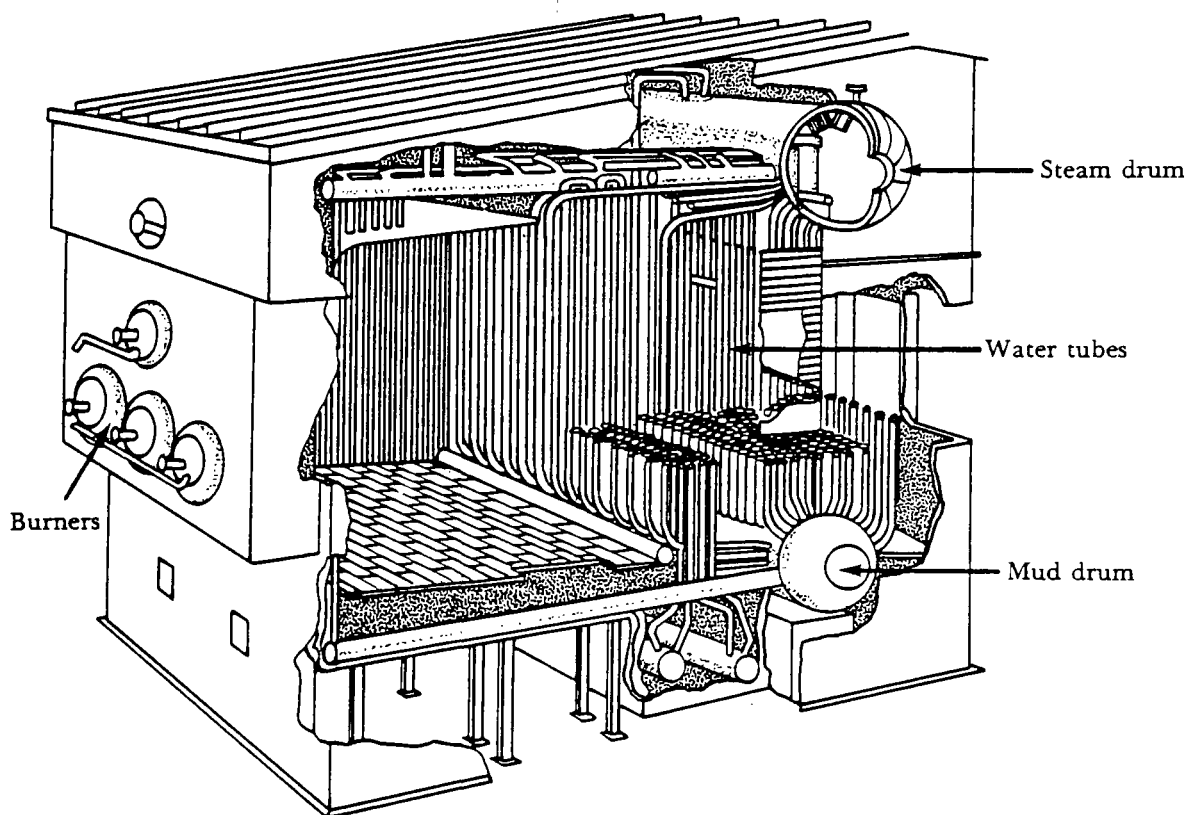
Figure 1-3. Typical fire-tube boiler with a refractory-lined firebox.

Water-Tube Boilers

Water-tube boilers are constructed in a wide range of sizes. All large steam generators are water-tube boilers. Hot combustion products pass over tube sections containing water. Water is boiled to make steam that is collected in *steam drums* in the furnace. These boilers are used when large amounts of high pressure steam are needed.

The cross-sectional area of each water tube is much smaller than that of the shell used in a fire-tube boiler. Therefore, water tubes can handle higher pressures and temperatures than can fire tubes. Pressure can be as high as 5000 psig and temperatures can be as high as 1000°F.

The layouts of the tubes and drums vary depending on their size and the type of fuel burned. Both bent and straight tubes can be connected to one or more drums. Figure 1-4 shows a water-tube boiler with two drums. The lower drum is usually called the mud drum and contains water. The upper drum, called the steam drum, contains both steam and water (condensed steam). Units such as these are usually assembled in the field.



Source: Babcock and Wilcox, 1978.

Figure 1-4. Typical water-tube boiler.

Figure 1-5 shows a water-tube boiler that has four drums. Water enters the top drum on the right-hand side of the boiler. This drum contains a mixture of steam and water. Water flows vertically through tubes called downcomers to the bottom drum (mud drum). Mud drums are occasionally called water-wall headers. Heated water moves up through tubes called risers to the center drum and then back to the top drum. Here, steam is separated, some of it condensing and falling back into this drum. Separated steam flows through a tube into a steam drum, located in the top left-hand corner of the boiler. Steam in the steam drum is drier because most of the moisture has been removed by steam separators.

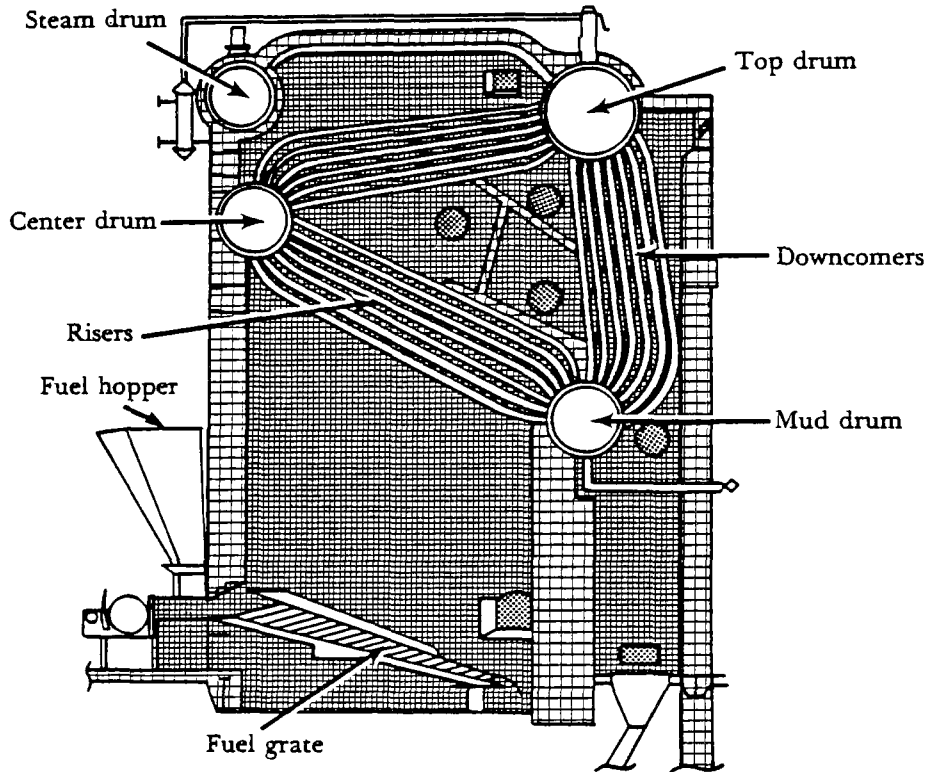
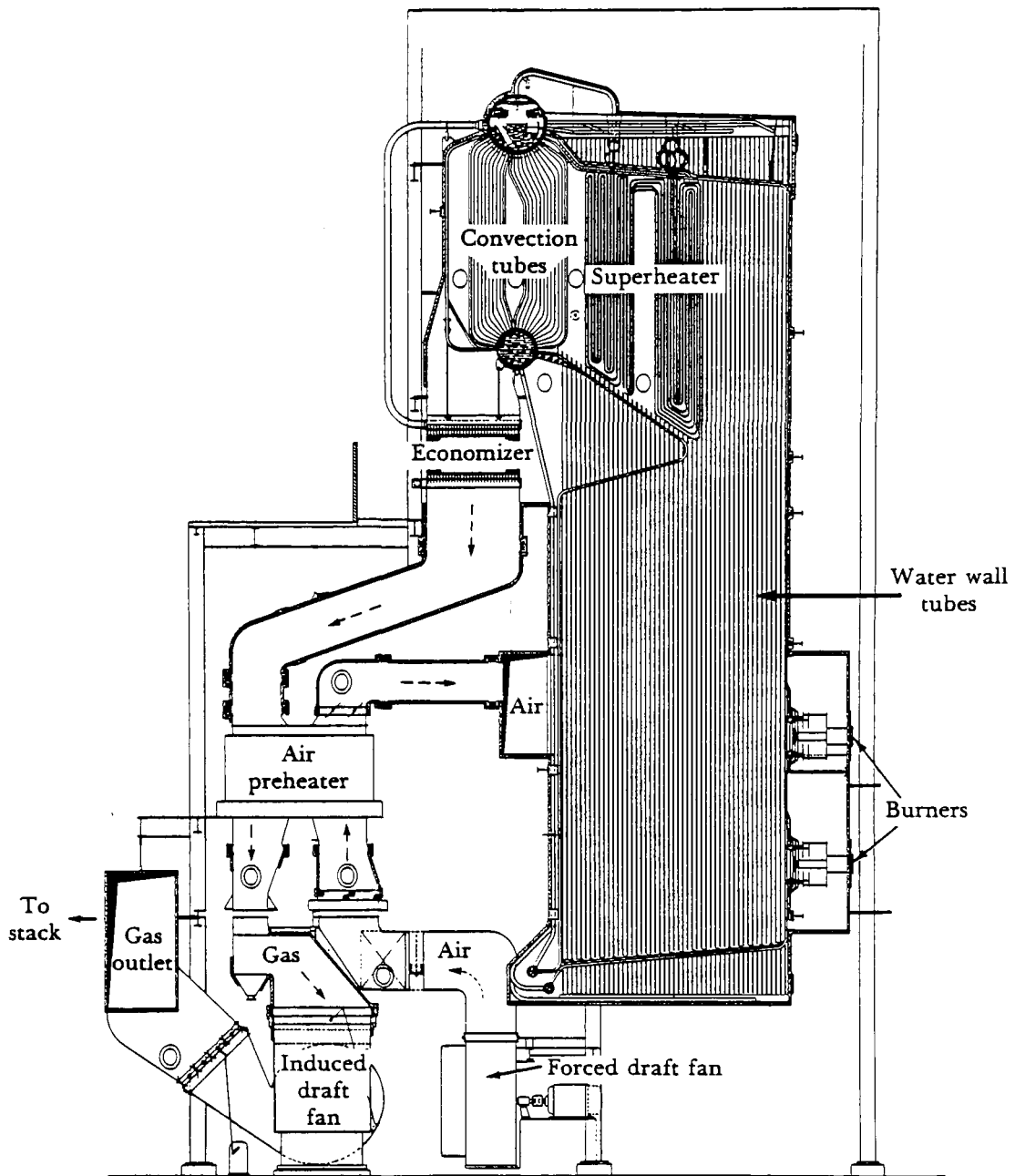


Figure 1-5. Water-tube boiler with four drums.

Large water-tube boilers that make steam for generating electricity are very complicated in design. Figure 1-6 shows the tube sections of a typical large water-tube boiler. Each section is designed to extract as much heat as possible from the flue gas. The five main tube sections of the boiler are the water walls (or fire walls), convection tubes, superheater, economizer, and air preheater.



Source: Babcock and Wilcox, 1978.

Figure 1-6. Water-tube boiler showing the various tube sections.

Water Walls

Most modern large water-tube boilers have tubes that completely surround the firebox or furnace, called *water walls* or *fire walls*. They are exposed to intense radiant heat in the firebox. Because these tubes contain water, they also help cool the walls of the furnace, thus eliminating the need for a thick refractory lining. Some boilers use tubes that are lined with refractory as shown in Figure 1-7. Others use water walls that are metal tubes with bars welded between them (Figure 1-8). Block insulation separates the metal tubes from the outside wall made of metal lagging. These are called membrane walls. Special refractory materials are occasionally used to help protect them from molten slag and resulting erosion. In addition, water walls and burners are carefully designed to prevent flames from impinging on tube surfaces which causes them to overheat and eventually burst.

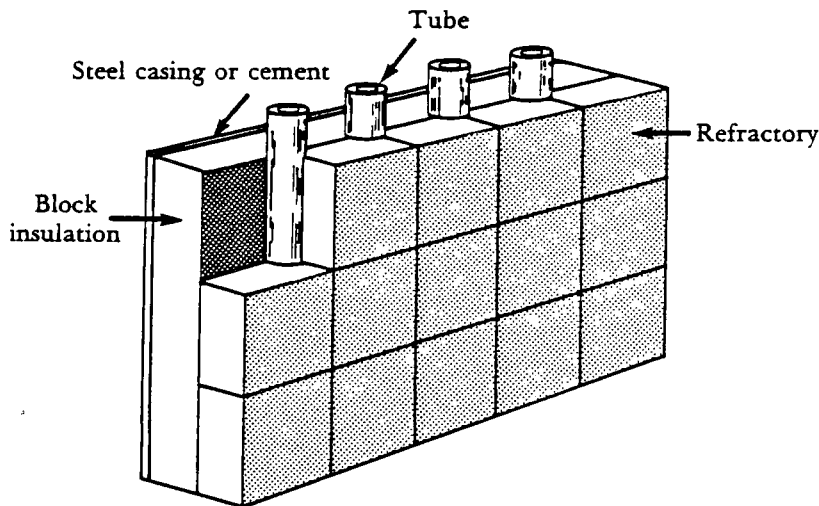
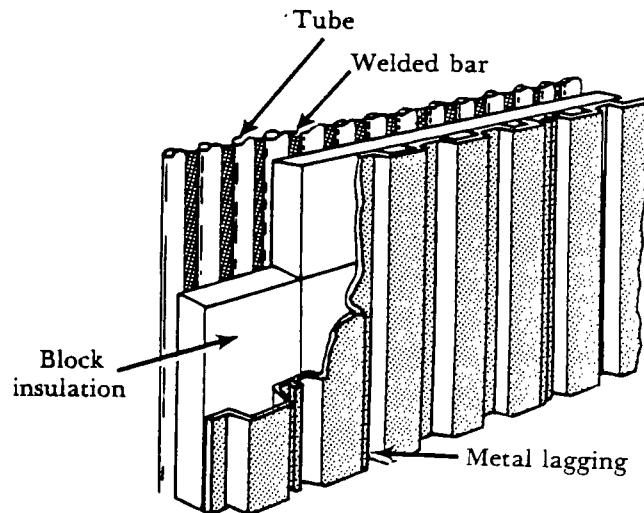


Figure 1-7. Water walls with partial refractory lining.



Source: Babcock and Wilcox, 1978.

Figure 1-8. Membrane water walls.

Water in the water walls forms steam bubbles which rise through tubes, called risers, and are collected in a steam drum located in the top part of the boiler. Some steam condenses out and drains back down to the bottom of the boiler through downcomer tubes. These tubes are usually not directly exposed to the fire in the firebox and are, therefore, relatively cool. The downcomers connect to water-wall headers located in the base of the furnace.

Figure 1-9 shows a simplified representation of a single circuit. The flow of water and steam in this arrangement occurs because of the difference in densities of water and steam. Water is denser and will flow down through the downcomers while steam bubbles up through the risers. The steam and water loops are made by using a number of drums, many riser tubes, and a few large downcomer tubes, depending on the boiler design. In large boilers, tube layout becomes quite complex. Downcomers are exposed to some heat and the force available for natural water circulation becomes smaller. Boilers producing high pressure steam generally use pumps to circulate the water from the downcomers into the water-wall headers.

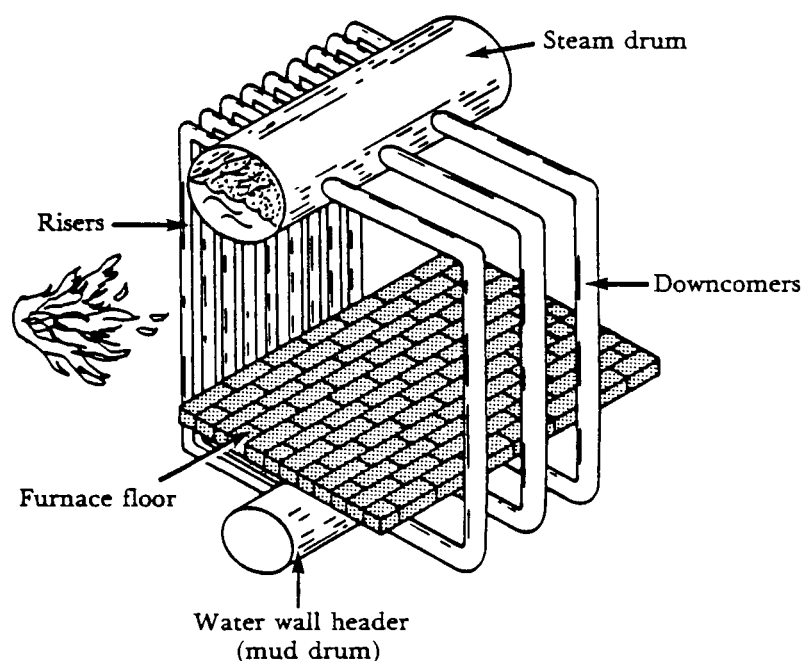


Figure 1-9. Simplified representation of a single circuit.

Convection Tubes, Steam Drums, and Superheaters

Hot flue gas is pulled through the boiler by an induced draft fan. Hot flue gas passes over tubes located in the upper portion of the boiler. Because heat is transferred by convection, these are called convection tubes. Water in the water wall tubes turns into steam and is collected in the steam drum or drums located in the convection section (Figure 1-10). Steam and water that may have condensed when reaching the steam drum are heated as hot flue gas moves over and around the convection tubes.

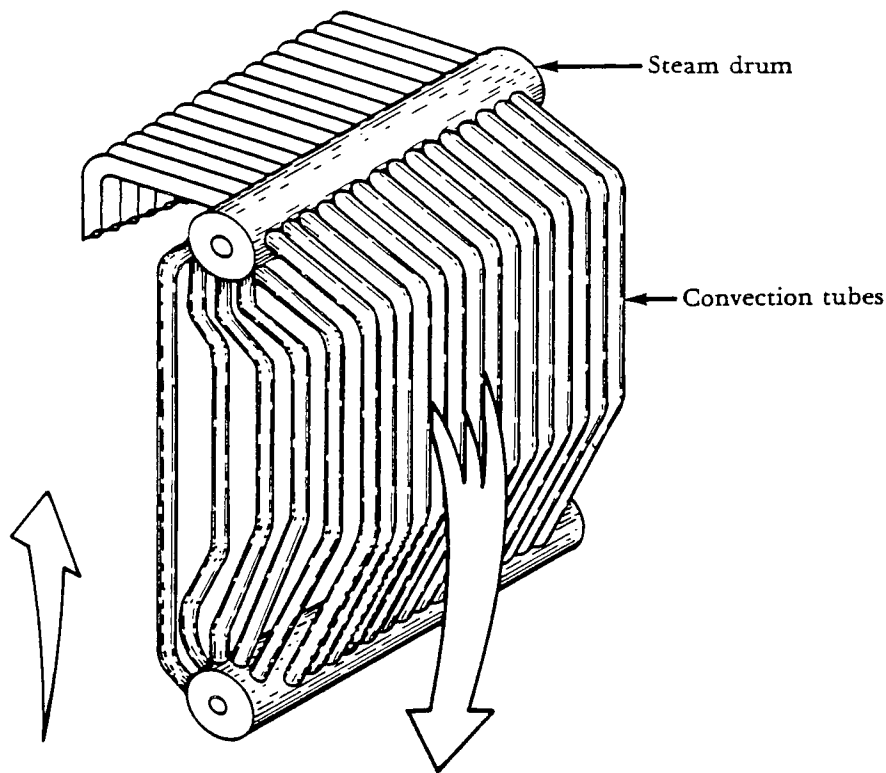
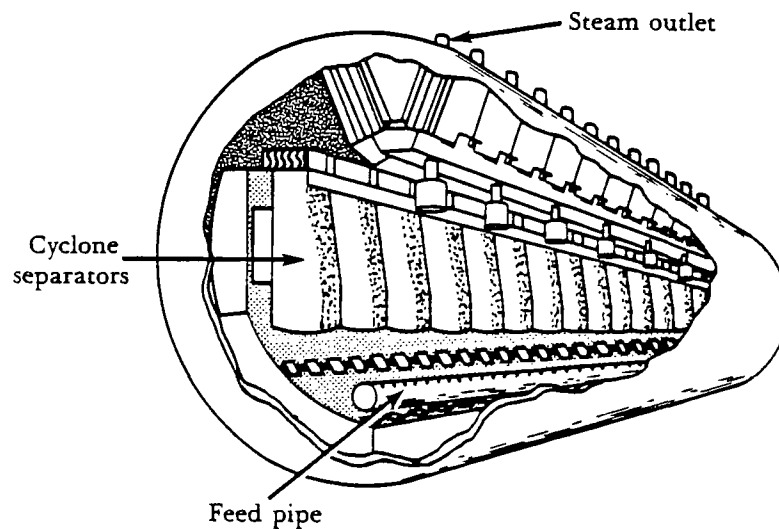


Figure 1-10. Convection section.

Steam drums used to collect and separate steam, are long and cylindrical. They contain approximately 50% steam and 50% water. Some of the water in the drum is condensed steam, the other is makeup water that is needed when steam is withdrawn for uses in the plant. A typical steam drum is shown in Figure 1-11.



Source: Babcock and Wilcox, 1978.

Figure 1-11. Typical steam drum.

Heated feedwater enters the steam drum through internal feed pipes located along the entire length of the drum bottom. Perforated holes in the feed pipes allow water to flow into the steam drums. Figure 1-12 shows components of a steam drum in more detail. Steam and water are usually separated by *cyclone separators*, open at the top and bottom. Steam and water from the water-wall tubes enter the base of each cyclone separator. Water is thrown to the side of the cyclone by centrifugal force and drains to the bottom of the drum. Steam first passes through baffles or chevron blades at the top of the cyclone, then through drying screens or chevron blades at the top of the drum. As the steam touches the screens or chevron blades, additional moisture will cling to the surfaces and be removed. Steam is now drier before it enters the superheater.

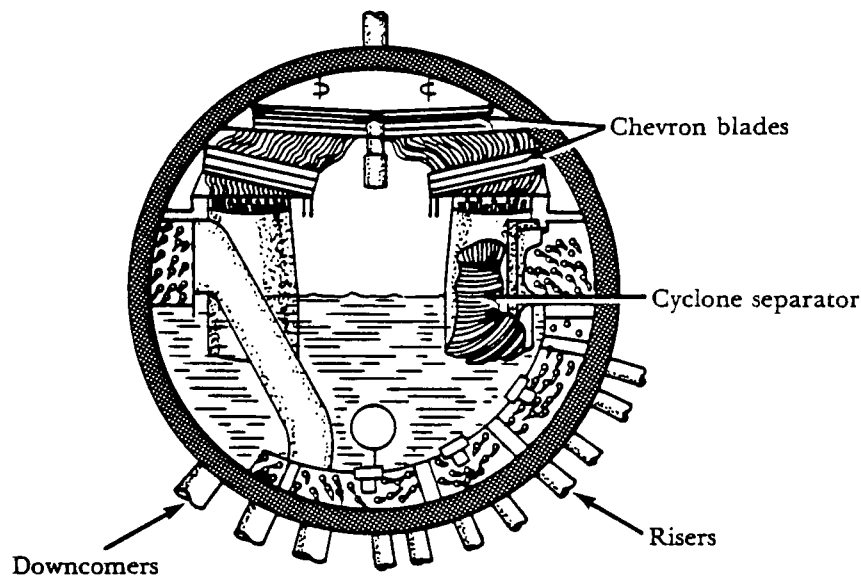


Figure 1-12. Detail of steam drum.

Steam leaves the steam drum at approximately 650°F. In some cases, the steam would be ready to be used in an industrial process. However, in boilers used in power plants and many industrial processes, steam is heated to higher temperatures in tube sections called *superheaters* (Figure 1-13). Steam leaving superheaters can have temperatures as high as 1000°F. Many boilers have a number of superheaters. Each is named for its location in the boiler. For example, steam from the steam drum usually passes into a primary superheater, or convection superheater. This superheater is heated by convection heat—thus its name—convection superheater. Steam then goes to a radiant superheater that receives radiant heat directly from the fire in the furnace—thus its name. Steam can then go into pendant superheaters that hang from the roof of the boiler. These are also called reheaters because steam that has made one pass through the turbine is reheated in this tube section. Superheated steam has several advantages over ordinary steam. It is hotter; therefore, boiler efficiency is increased. Also, since superheated steam is drier, it does not easily condense into droplets that can corrode and erode turbine parts.

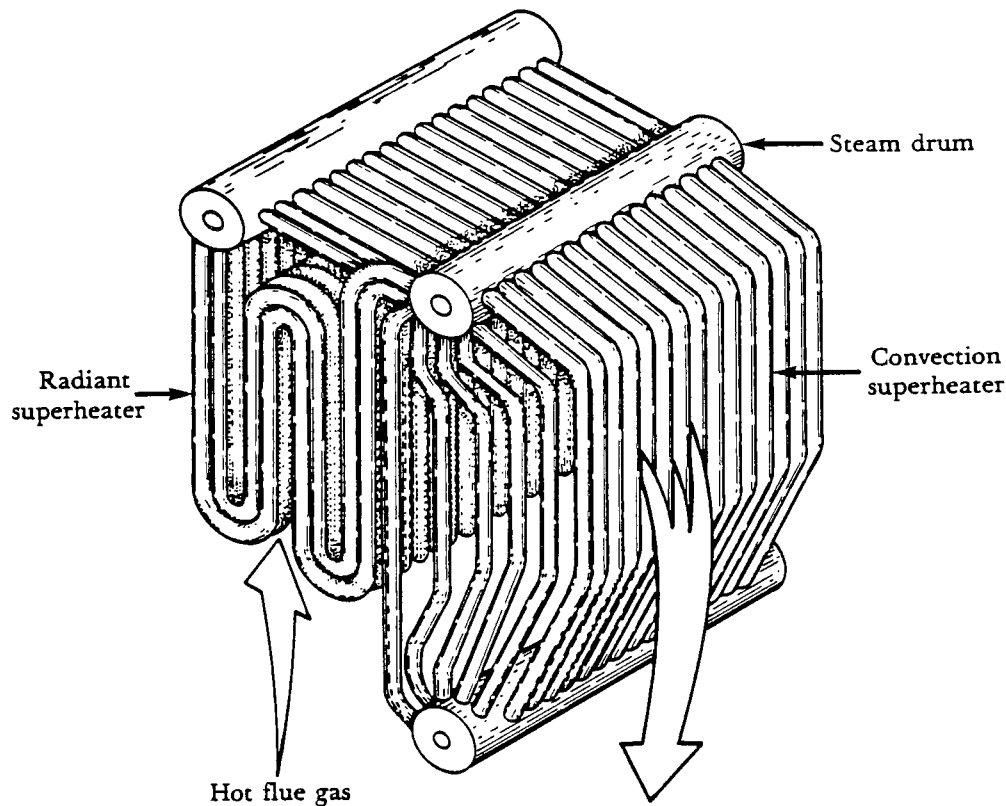


Figure 1-13. Superheaters.

Economizer

Boiler feedwater, or makeup water, is heated in a tube section called an economizer before it is delivered to the steam drum. As we said earlier, steam is drawn from the steam drums to the turbine as the demand for electricity increases, or to the plant as the demand for process steam increases. To replace this, an equivalent amount of water, called makeup water, or feedwater, is pumped through economizer tubes where it is heated before it enters the steam drum (Figure 1-14). Water leaving an economizer reaches a temperature of at least 212°F. In boilers used in power plants, the feedwater coming into the economizer is preheated by feedwater heaters to get it to very high temperatures. Water temperature leaving an economizer/feedwater heater system can be as high as 600°F.

Economizer tubes usually have fins that help promote heat transfer from the hot flue gas to the water flowing through the economizer. Heated water from the economizer is collected in the outlet header. A header is a long pipe or tube with holes in its sides to allow water (or steam in the case of a steam header) to be evenly collected or distributed. From the outlet header, feedwater flows into the steam drum.

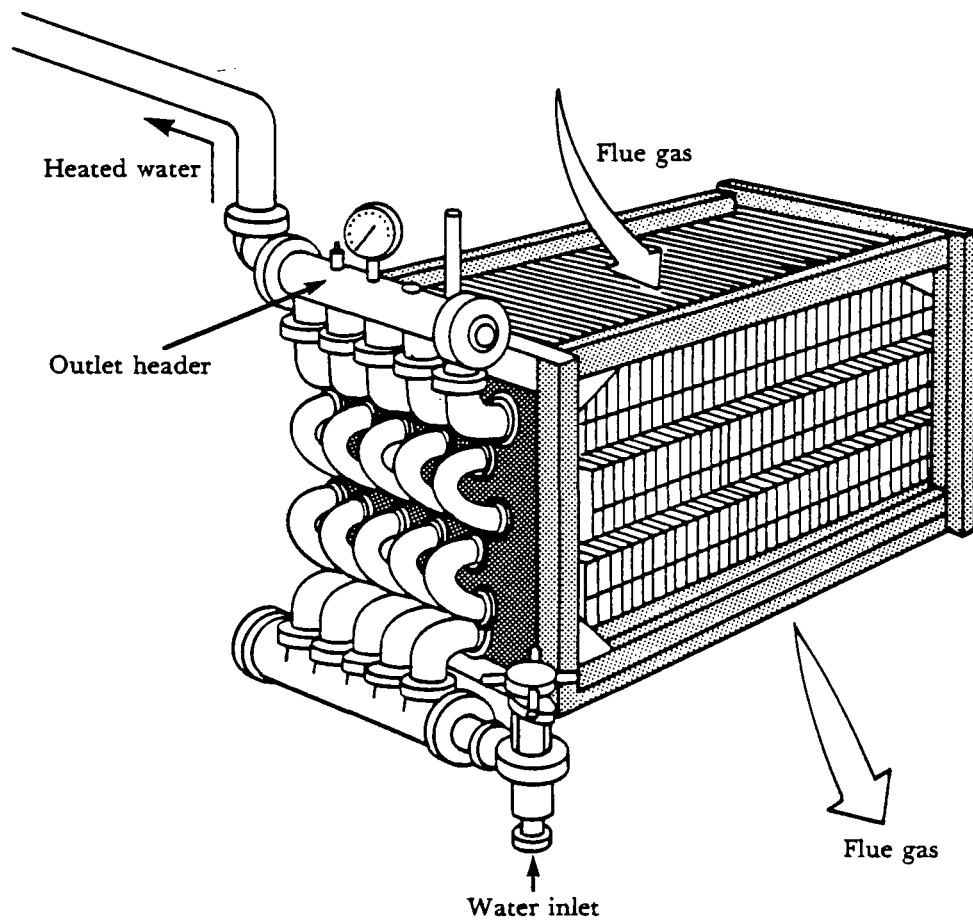


Figure 1-14. Economizer.

Air Preheater

An air preheater is a tube section that preheats the air used for burning the fuel in the furnace. It is usually placed after the economizer and before or after the air pollution control equipment in a boiler system. The most widely used are *tubular*, *rotary*, and *Rothemuhle* air preheaters.

A tubular air preheater has a number of small tubes, 1 to 2 in. in diameter, through which the flue gas flows. Cool air is forced over and around the tubes by a small forced draft fan (Figure 1-15). The hot flue gas passing through the tubes transfers heat to the "cool" air. Warmed air leaving the air preheater is sent to burners where it is used to burn fuel.

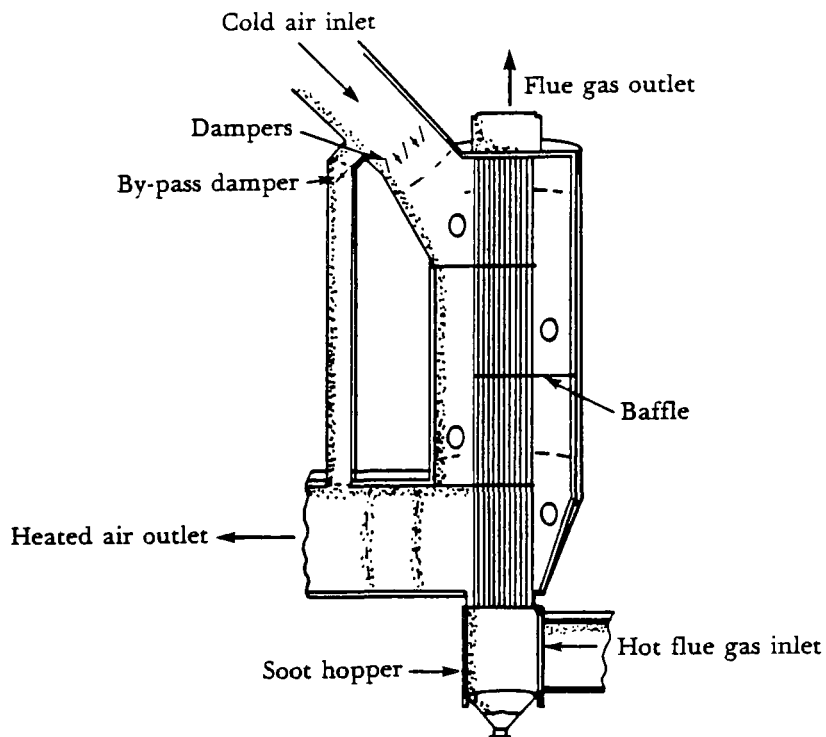


Figure 1-15. Tubular air preheater.

Many modern large water tube boilers use rotary, or regenerative, air preheaters. Regenerative air preheaters are large heat exchanger wheels that contain heat absorbing materials (Figure 1-16). In these devices, hot flue gas flows through one portion of the wheel while cool, clean combustion air passes through the remaining portion. Heat is stored in the absorbing material through which the hot flue gas flows. As the wheel revolves, the cold combustion air passes through these hot surfaces and becomes heated. This preheated air is sent to the burners and is burned with fuel in the firebox. The absorbing material of the wheel is constructed of corrugated sheet metal plates. The plates, arranged in a honeycomb matrix, provide both maximum heat transfer and air flow between the plates. These devices are more efficient than shell-and-tube heat exchangers.

The Rothemuhle regenerative air preheater consists of a stationary heating element and two rotating air hoods. Hot flue gas enters a large duct surrounding the air preheater. The flue gas flows over a portion of the heating surface not blocked by the hoods, thus heating it. The air hoods rotate slowly around the stationary heating surface causing the cool air to become heated (Figure 1-17).

Air preheaters can improve the overall boiler efficiency from 2 to 10%. Preheated air accelerates combustion by producing rapid ignition of fuels. It also allows using a low amount of excess air (see Lesson 2), thereby increasing boiler efficiency.

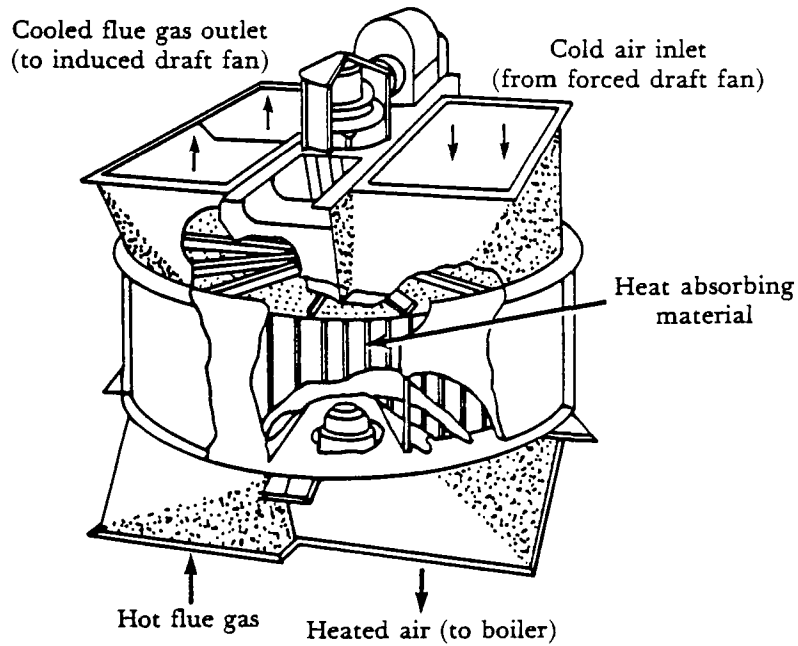
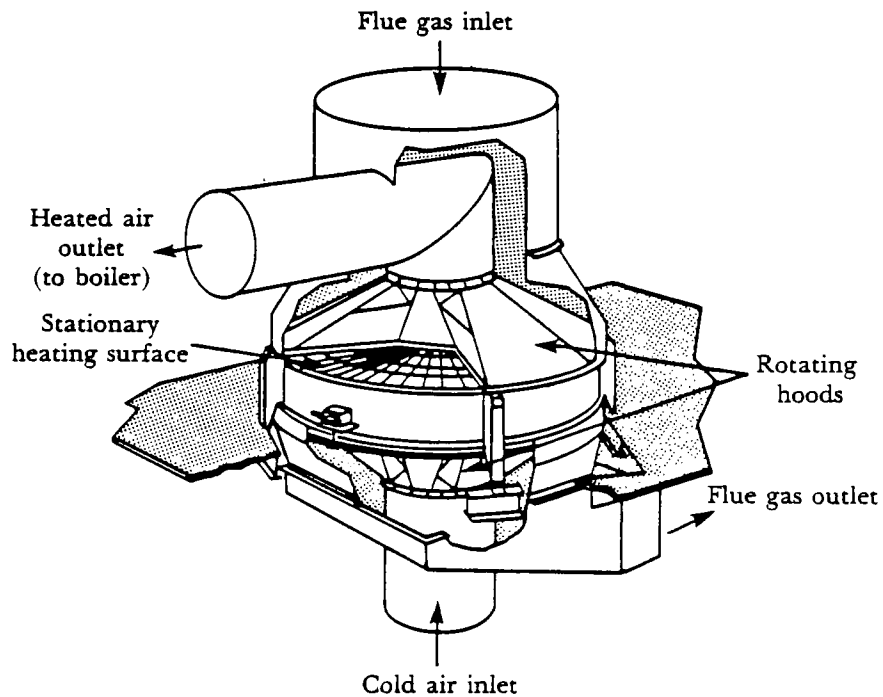


Figure 1-16. Rotary air preheater.



Source: Babcock and Wilcox, 1978.

Figure 1-17. Rothemuhle regenerative air preheater.

Boiler Sizes and Ratings

Boilers are usually grouped by capacity on another classification such as the pressure at which it operates. Capacity refers to the heat or steam output of a boiler. The terms used to express capacity depend on the size of the boiler. Boiler manufacturers designate the capacity of medium and large boilers in terms of pounds of steam generated per hour at a specific temperature and pressure. Small boilers are usually designated by the total square feet of heating surface, horsepower (hp), or percentage of rating (TPC Training Systems, 1975).

The total heating surface refers to all heat exchanger surfaces exposed to the hot flue gas on one side and the water or steam on the other side. Boilers are also rated by boiler horsepower—one boiler hp is equal to a heat output of 33,475 Btu per hour. The rated hp of a boiler depends on the boiler design and its amount of heating surface. Occasionally boilers are designated by the percentage of rating—the actual capacity divided by the rated capacity. This designation is used when a boiler produces more steam than the rated capacity. Thus, if a boiler produces two times the amount of its rated capacity, it operates at 200% of rating.

Boilers are also classified by the pressure at which they operate. The five common groupings are: below 900 psi, 900 to 1000 psi, 1200 to 1500 psi, 1800 to 2500 psi, and 3500 to 5000 psi. Fire-tube boilers usually operate between 50 and 250 psi. Water-tube boilers operate at higher pressures. Large power plant boilers can operate with pressures as high as 5000 psi.

Boilers are also rated by their heat input capacity. The heat input capacity is the amount of heat, in units of British Thermal Units per hour (Btu/hr), Joules per hour (J/h), that is generated by burning fuel in the furnace. Boilers are also rated in terms of Megawatts (MW) of thermal energy produced. A boiler rated at 73 MW has a heat input of approximately 250×10^6 Btu/hr. Many air pollution control agencies adopt regulations to limit the air pollution emissions in units of ng/J or lb/ 10^6 Btu.

Comparing Fire-tube and Water-tube Boilers

Fire-tube boilers are usually smaller, occupy a minimum of floor space, have a lower initial cost, and require very little installation time than do water-tube boilers. However, they do have some disadvantages. The water volume is very large and circulation is poor, making them slow to respond to changes in steam demand. The drums, or shells, containing the water are very large and cannot be economically built to withstand higher operating pressures. Pressures are usually less than 250 psi. Drums and joints are exposed to the furnace, increasing the likelihood of explosion. The pressure, temperature, and the amount of steam that can be produced are not as high as with water-tube boilers.

Both fire-tube and water-tube boilers are constructed as packaged boilers. Packaged boilers are shop assembled with burners, tubes, fans, and controls built into the boiler as one unit. These units can be placed into service very quickly. The packaged units have automatic controls, thus reducing labor costs. Because these units are compact, they can be difficult to get inside of for maintenance. However, because

they are more compact, they may be used in locations where field erected units will not fit. Packaged units generally must burn liquid or gaseous fuels.

Water-tube boilers are available in various sizes to produce high-pressure, high-temperature steam. Because these units use small diameter tubes, they can produce high-pressure steam without a great risk of explosion. They can also respond rapidly to changes in steam demand. Water-tube boilers usually have more elaborate settings and controls, and the cost per pound of steam is usually higher than for a similar-sized fire-tube boiler. Large water-tube boilers are usually field erected, making the installation more difficult and time consuming. Water-tube boilers can be designed to burn solid, liquid, or gaseous fuels. Table 1-1 lists the general ratings of fire-tube and water-tube boilers and their various applications.

Table 1-1. General ratings of boilers.

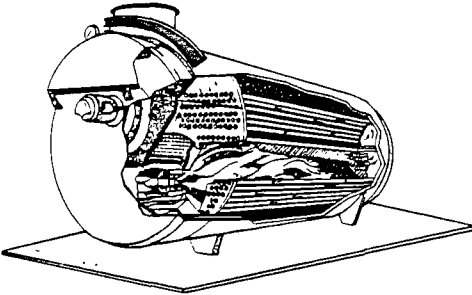
Application	Boiler design	Rating (psi)
Residential and small commercial	fire-tube	50- 250
	water-tube	50- 900
Commercial and small industrial	fire-tube	50- 250
	water-tube	50-1800
Industrial	water-tube	900-2500
Utility	water-tube	2500-5000

Summary

Selecting a boiler involves evaluating many factors including availability, initial costs, operating and maintenance costs, labor, space, and the pressure and temperature of steam needed for the process. One of the most important factors is the fuel to be burned—its type and cost. During the life of the boiler, the fuel costs can be two to six times the initial cost of the boiler. It is very important to operate the boiler as it was designed to help keep the fuel costs low and improve overall boiler efficiency. These topics will be discussed in the following lessons.

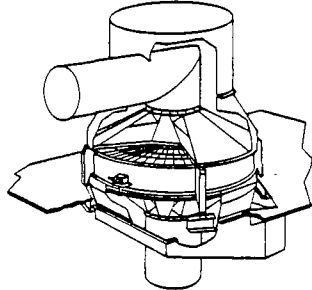
Review Exercise

1. In _____ boilers, combustion products pass through the inside of heat exchanger tubes while water and steam are contained outside the tubes by an outer shell.	
2. In _____ boilers, hot combustion products pass over tube sections that contain water. Water is boiled to make steam that is collected in steam drums.	1. fire-tube
	2. water-tube

<p>3. The _____ is a section of tubes that heats the feed-water before it is delivered to the boiler.</p> <ol style="list-style-type: none"> convection economizer superheater air preheater 	
<p>4. True or False? The temperature of steam in the superheater can be as high as 538°C (1000°F).</p>	<p>3. b. economizer</p>
<p>5. Heat transfer through space from a hot object to a cooler one is called</p> <ol style="list-style-type: none"> conduction. convection. radiation. 	<p>4. True</p>
<p>6. Heat transferred by hot flue gas flowing over and around boiler tubes is called</p> <ol style="list-style-type: none"> conduction. convection. radiation. 	<p>5. c. radiation.</p>
<p>7. The following illustration is of a</p> <ol style="list-style-type: none"> Scotch marine boiler. horizontal return tube boiler. fire-tube boiler with a refractory-lined firebox. packaged water-tube boiler. 	<p>6. b. convection.</p>
<p>8. In water-tube boilers, the tubes surrounding the firebox are called</p> <ol style="list-style-type: none"> superheaters or convection tubes. economizers or air preheaters. water walls or fire walls. 	<p>7. b. horizontal return tube boiler.</p>
	<p>8. c. water walls or fire walls</p>

9. In a water-tube boiler, water forms into steam, moves through tubes called _____, and is collected in a _____. a. risers, steam drum b. downcomers, steam drum c. risers, downcomer	
10. True or False? Boilers producing high-pressure steam generally use pumps to circulate the water from the downcomers into the water-wall headers.	9. a. risers, steam drum
11. Heated feedwater enters the steam drum through internal feed pipes located along the length of the drum a. top. b. bottom. c. back wall.	10. True
12. In a steam drum, steam and water are usually separated by a. packed beds. b. cyclone separators. c. water pools.	11. b. bottom.
13. True or False? Water-tube boilers can have a number of superheaters called convection, pendant, and radiant superheaters.	12. b. cyclone separators.
14. For many water-tube boilers, steam is drawn from the boiler as makeup water is pumped through a(n) _____ where it is heated before it enters a(n) a. preheater, economizer. b. superheater, mud drum. c. economizer, steam drum.	13. True
15. True or False? In a tubular air preheater, cool combustion air is heated by a revolving heat wheel.	14. c. economizer, steam drum
	15. False

16. The following illustration is of a
- rotary air preheater.
 - tubular air preheater.
 - economizer.
 - Rothemuhle regenerative air preheater.



17. Boilers are usually rated by
- boiler horsepower.
 - operating pressure.
 - heat input capacity.
 - all of the above

16. d. Rothemuhle regenerative air preheater.

18. Fire-tube boilers operate at higher/lower pressures than do water tube boilers.

17. d. all of the above

18. lower

References

- Babcock and Wilcox. 1978. *Steam—Its Generation and Use*. New York: The Babcock and Wilcox Company.
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Lesson 2

Combustion Efficiency

Lesson Goal and Objectives

Goal

To familiarize you with combustion principles and with the factors that affect combustion efficiency in boilers.

Objectives

Upon completing this lesson, you should be able to—

1. describe the three conditions that are necessary for complete combustion and their relationship to each other,
2. define *stoichiometric amount of oxygen*,
3. define the terms *lower explosive limit*, *upper explosive limit*, *excess air*, *higher heating value*, and *net heating value*,
4. estimate combustion efficiency using charts, figures, and calculation forms, and
5. list areas of potential heat loss in a boiler.

Combustion Variables

Combustion is a chemical process occurring from the rapid combination of oxygen with combustible materials, or fuel, that produces heat. In a boiler, fuel such as coal oil, gas, or wood is mixed with air at elevated temperatures producing heat and the oxides of many of the elements contained in the fuel.

Most fuels used in boilers are composed of essentially carbon and hydrogen, but can also contain other elements such as nitrogen and sulfur. The products resulting from complete combustion of hydrocarbon, or organic fuels are carbon dioxide and water vapor. However, if the fuel contains oxygen, the resulting flue gas may contain aldehydes and organic acids creating an air pollution problem. The simplified reactions of carbon and hydrogen are given as:



Equations 2-1 and 2-2 show that the final products resulting from complete combustion of organic fuels are carbon dioxide, water, and energy in the form of heat. This is the ideal condition that all boiler operators strive to achieve. However,

incomplete combustion can occur if combustion conditions are not adequate. When combustion is incomplete, smoke, carbon monoxide, and other partially oxidized products will be formed. These are air pollutants or undesired products. In addition, less heat will be produced when combustion is incomplete.

If the fuel should contain elements such as sulfur and nitrogen, the flue gas produced will contain the oxides of these elements **even when** combustion is complete. Sulfur oxides and nitrogen oxides are air pollutants that can be harmful if emitted in significant amounts. Air pollution control techniques will be discussed in Lesson 6.

To achieve complete combustion once the air (oxygen) and fuel have been brought into contact, the following conditions are necessary:

- temperature high enough to ignite the fuel and air mixture
- turbulent mixing of the fuel and air, and
- sufficient residence time for the reaction to occur.

Called the “three T’s of combustion,” turbulence, temperature, and time, these conditions govern the speed and completeness of a reaction. They depend on each other, because changing one affects the other two.

Air Supply

The amount of air needed for combustion in a boiler depends on the fuel, the equipment used, and the operating conditions of the unit. If there is too much air, an excessive amount of hot gases will be discharged from the boiler as well as a correspondingly high heat loss. If there is not enough air, unburned fuel will be discharged from the boiler. Therefore, it is important to design and operate the boiler with the appropriate amount of air to completely combust the fuel fed to the furnace.

Turbulence

Turbulent mixing of the air (oxygen) and fuel is essential for efficient combustion. Each combustible particle must contact oxygen before it will burn. If the air and fuel mixing in the combustion chamber or in the fuel bed is poor, there will be too much combustion air in some places and not enough in others. Inadequate mixing can result in incomplete combustion products and unburned fuel being emitted from the boiler.

Temperature

The rate at which a combustible material is oxidized is greatly affected by the temperature. The higher the temperature, the faster the oxidation reaction will proceed. The chemical reaction of fuel and oxygen can occur even at ambient temperatures. For this reason, a pile of coal can be a fire hazard. Small amounts of heat are given off as the coal slowly oxidizes. This in turn raises the temperature of the coal pile and increases the oxidation rate, liberating more heat. Eventually, a full-fledged fire can break out.

In boilers, when the combustible material reaches its ignition temperature, the rate of oxidation is accelerated to the combustion point. Once the fuel is ignited, the heat released during combustion will be high enough to sustain the continual oxidation of the fuel.

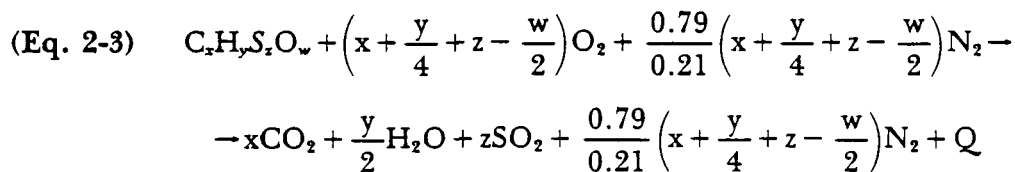
Time

Air supply, turbulence, and temperature determine the rate at which combustion proceeds. However, a sufficient amount of time is required to ensure that the fuel completely burns. If the residence time is not high enough, unburned fuel or partially oxidized compounds will be emitted from the boiler. This causes an appreciable heat loss in the boiler and pollutants to be emitted into the atmosphere. The residence time is directly related to the volume of the furnace chamber. The larger the chamber volume for a set flow rate, the longer the residence time will be.

Combustion Calculations

Stoichiometric Amount of Oxygen

Oxygen is necessary for combustion to occur. To achieve complete combustion of an organic compound, a sufficient supply of oxygen must be present to convert all of the carbon to CO_2 . This quantity of oxygen is referred to as the *stoichiometric* or *theoretical amount*. The stoichiometric amount of oxygen is determined from a balanced chemical equation summarizing the oxidation reactions. Consider a generalized fuel with a chemical formula $\text{C}_x\text{H}_y\text{S}_z\text{O}_w$ where the indices x , y , z , and w represent the relative number of atoms of carbon, hydrogen, sulfur, and oxygen respectively. Balancing the chemical reaction for the complete oxidation (combustion) of this fuel with oxygen from air gives:

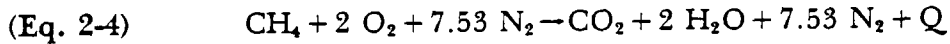


Where: Q = heat of combustion

The above reaction assumes that:

- air consists of 21% by volume of oxygen with the remaining 79% made up of nitrogen and other inert gases;
- combined oxygen in fuel is available for combustion, thus reducing air requirements;
- fuel contains no combined nitrogen, so no "fuel NO_x " is produced;
- "thermal NO_x " via the nitrogen fixation is small, so that it is neglected in stoichiometric air calculations;
- sulfur in fuel is oxidized to SO_2 with negligible SO_3 formation.

For example, to combust methane (CH_4) Equation 2-3 reduces to:



$$\begin{array}{ccc} \text{Moles or relative volumes} & & \\ \underline{1 + 2 + 7.53} & \rightarrow & \underline{1 + 2 + 7.53} \\ \text{Total air required} & & \text{Total flue gases} \end{array}$$

For every mole or standard cubic foot of CH_4 burned, the reaction requires 9.53 moles or standard cubic feet of air for complete combustion. A listing of the theoretical air requirements for a number of fuels are given in Table 2-1.

Excess Air

In boilers, more than the stoichiometric amount of air is used to ensure complete combustion. This extra volume is referred to as *excess air*. If ideal mixing were achievable, no excess air would be necessary. However, most combustion devices are not capable of achieving ideal mixing of the fuel and air streams. The amount of excess air is held to a minimum in order to reduce heat losses. Excess air takes no part in the reaction but does absorb some of the heat produced. To raise the excess air to the combustion temperature, additional fuel must be used to make up for this loss of heat. Operating at a high volume of excess air can be very costly in terms of the added fuel required.

Depending on the amount of excess air, different concentrations of CO_2 and O_2 in the stack gas will result, as shown in Figure 2-1.

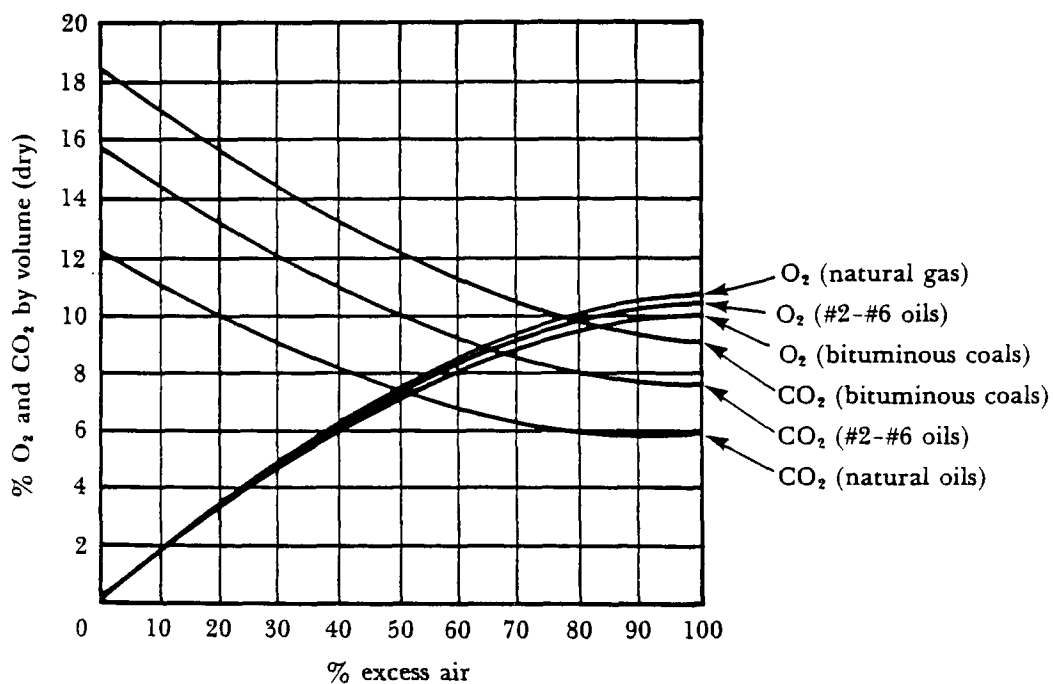


Figure 2-1. Excess air concentrations of CO_2 and O_2 in stack.

**Table 2-1. Combustion constants and approximate limits of flammability
of gases and vapors in air.**

Substance	Lb/ft ³	Ft ³ /lb	Heat of combustion				For 100% total air (mol/mol of combustible) (ft ³ /ft ³ of combustible)						For 100% total air (lb/lb of combustible)						Flammability limits (% by volume)	
			(Btu/ft ³)		(Btu/lb)		Required for combustion			Flue products			Required for combustion			Flue products				
			Gross (high)	Net (low)	Gross (high)	Net (low)	O ₂	N ₂	Air	CO ₂	H ₂ O	N ₂	O ₂	N ₂	Air	CO ₂	H ₂ O	N ₂	LEL	UEL
Carbon, C*	—	—	—	—	14,093	14,093	1.0	3.76	4.76	1.0	—	3.76	2.66	8.86	11.53	3.66	—	8.86	—	—
Hydrogen, H ₂	0.0053	187.723	325	275	61,100	51,623	0.5	1.88	2.38	—	1.0	1.88	7.94	26.41	34.34	—	8.94	26.41	4.00	74.20
Oxygen, O ₂	0.0846	11.819	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Nitrogen (atm), N ₂	0.0744	13.443	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Carbon monoxide, CO	0.0740	13.506	322	322	4,347	4,347	0.5	1.88	2.38	1.0	—	1.88	0.57	1.90	2.47	1.57	—	1.90	12.50	74.20
Carbon dioxide, CO ₂	0.1170	8.548	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Paraffin series																				
Methane, CH ₄	0.0424	23.565	1013	913	23,879	21,520	2.0	7.53	9.53	1.0	2.0	7.53	3.99	13.28	17.27	2.74	2.25	13.28	5.00	15.00
Ethane, C ₂ H ₆	0.0803	12.455	1792	1641	22,320	20,432	3.5	13.18	16.68	2.0	3.0	13.18	3.73	12.39	16.12	2.93	1.80	12.39	3.00	12.50
Propane, C ₃ H ₈	0.1196	8.365	2590	2385	21,661	19,944	5.0	18.82	23.82	3.0	4.0	18.82	3.63	12.07	15.70	2.99	1.68	12.07	2.12	9.35
n-Butane, C ₄ H ₁₀	0.1582	6.321	3370	3113	21,308	19,680	6.5	24.47	30.97	4.0	5.0	24.47	3.58	11.91	15.49	3.03	1.55	11.91	1.86	8.41
Isobutane, C ₄ H ₁₀	0.1582	6.321	3363	3105	21,257	19,629	6.5	24.47	30.97	4.0	5.0	24.47	3.58	11.91	15.49	3.03	1.55	11.91	1.80	8.44
n-Pentane, C ₅ H ₁₂	0.1904	5.252	4016	3709	21,091	19,517	8.0	30.11	38.11	5.0	6.0	30.11	3.55	11.81	15.35	3.05	1.50	11.81	—	—
Isopentane, C ₅ H ₁₂	0.1904	5.252	4008	3716	21,052	19,478	8.0	30.11	38.11	5.0	6.0	30.11	3.55	11.81	15.35	3.05	1.50	11.81	—	—
Neopentane, C ₅ H ₁₂	0.1904	5.252	3993	3693	20,970	19,396	8.0	30.11	38.11	5.0	6.0	30.11	3.55	11.81	15.35	3.05	1.50	11.81	—	—
n-Hexane, C ₆ H ₁₄	0.2274	4.398	4762	4412	20,940	19,403	9.5	35.76	45.26	6.0	7.0	35.76	3.53	11.74	15.27	3.06	1.46	11.74	1.18	7.40
Olefin series																				
Ethylene, C ₂ H ₄	0.0746	13.412	1614	1513	21,644	20,295	3.0	11.29	14.29	2.0	2.0	11.29	3.42	11.39	14.81	3.14	1.29	11.39	2.75	28.60
Propylene, C ₃ H ₆	0.1110	9.007	2336	2186	21,041	19,691	4.5	16.94	21.44	3.0	3.0	16.94	3.42	11.39	14.81	3.14	1.29	11.39	2.00	11.10
n-Butene, C ₄ H ₈	0.1480	6.756	3084	2885	20,840	19,496	6.0	22.59	28.59	4.0	4.0	22.59	3.42	11.39	14.81	3.14	1.29	11.39	1.75	9.70
Isobutene, C ₄ H ₈	0.1480	6.756	3068	2869	20,730	19,382	6.0	22.59	28.59	4.0	4.0	22.59	3.42	11.39	14.81	3.14	1.29	11.39	—	—
n-Pentene, C ₅ H ₁₀	0.1852	5.400	3836	3586	20,712	19,363	7.5	28.23	35.73	5.0	5.0	28.23	3.42	11.39	14.81	3.14	1.29	11.39	—	—
Aromatic series																				
Benzene, C ₆ H ₆	0.2060	4.852	3751	3601	18,210	17,480	7.5	28.23	35.73	6.0	3.0	28.23	3.07	10.22	13.30	3.38	0.69	10.22	1.40	7.10
Toluene, C ₇ H ₈	0.2431	4.113	4484	4284	18,440	17,620	9.0	33.88	42.88	7.0	4.0	33.88	3.13	10.40	13.53	3.34	0.78	10.40	1.27	6.75
Xylene, C ₈ H ₁₀	0.2803	3.567	5230	4980	18,650	17,760	10.5	39.52	50.02	8.0	5.0	39.52	3.17	10.53	13.70	3.32	0.85	10.53	1.00	6.00
Miscellaneous gases																				
Acetylene, C ₂ H ₂	0.0697	14.344	1499	1448	21,500	20,776	2.5	9.41	11.91	2.0	1.0	9.41	3.07	10.22	13.30	3.38	0.69	10.22	—	—
Naphthalene, C ₁₀ H ₈	0.3384	2.955	5854	5654	17,298	16,708	12.0	45.17	57.17	10.0	4.0	45.17	3.00	9.97	12.96	3.43	0.56	9.97	—	—
Methyl alcohol, CH ₃ OH	0.0846	11.820	868	768	10,259	9,078	1.5	5.65	7.15	1.0	2.0	5.65	1.50	4.98	6.48	1.37	1.13	4.98	6.72	36.50
Ethyl alcohol, C ₂ H ₅ OH	0.1216	8.221	1600	1451	13,161	11,929	3.0	11.29	14.29	2.0	3.0	11.29	2.08	6.93	9.02	1.92	1.17	6.93	3.28	18.95
Ammonia, NH ₃	0.0456	21.914	441	365	9,668	8,001	0.75	2.82	3.57	—	1.5	3.32	1.41	4.69	6.10	—	1.59	5.51	15.50	27.00
Sulfur and sulfur compounds																				
Sulfur, S*	0.0911	10.979	—	—	3,983	3,983	1.0	3.76	4.76	1.0	—	3.76	1.00	3.29	4.29	2.00	—	3.29	—	—
Hydrogen sulfide, H ₂ S	0.1733	5.770	647	596	7,100	6,545	1.5	5.65	7.15	1.0	1.0	5.65	1.41	4.69	6.10	1.88	0.53	4.69	4.30	45.50
Sulfur dioxide, SO ₂	0.0476	21.017	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Water vapor, H ₂ O	0.0766	13.063	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Air	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Gasoline	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	1.40	7.60

*Carbon and sulfur are considered as gases for molal calculations only.

Sources: Adapted from *Fuel Flue Gases*, American Gas Association.
Combustion Flame and Explosions of Gases, 1951.

Figure 2-1 shows how the amount of excess air is indicated by the amount of CO₂ or O₂ measured in the flue gas. Flue gas can be analyzed for the percentage of CO₂, O₂, and CO by using an orsat apparatus or continuous monitors. As can be seen from Figure 2-1, when excess air is kept low, the concentration of CO₂ in the flue gas is high, while that of O₂ remains relatively low. The boiler should be operated with a minimal amount of excess air to promote good combustion and to prevent high heat loss.

Excess air can be calculated using Equation 2-5.

$$\text{(Eq. 2-5)} \quad \% \text{ EA} = \frac{\% \text{ O}_2 - 0.5 \% \text{ CO}}{0.264 \% \text{ N}_2 - (\% \text{ O}_2 - 0.5 \% \text{ CO})} \times 100$$

Example 2-1 will illustrate how to calculate excess air when the flue gas concentrations are known.

Example 2-1

Assume the flue gas from a boiler was analyzed with an orsat apparatus and found to contain the following concentrations:

Gas	Percent
CO ₂	17.0
O ₂	3.5
CO	0.02
N ₂	79.0

Using Equation 2-5, the percent excess air is:

$$\begin{aligned} \% \text{ EA} &= \frac{3.5 - 0.5 (0.02)}{0.264(79.0) - [3.5 - 0.05(0.02)]} \times 100 \\ &= \frac{3.5 - 0.01}{20.86 - 3.49} \times 100 \\ &= 0.201 \times 100 \\ &= 20.1\% \end{aligned}$$

Combustion Limits

Not all mixtures of fuel and air are able to support combustion. The flammable, or explosive limits, for a mixture are the maximum and minimum concentrations of fuel in air that will support combustion. The *lower explosive limit* (LEL) is defined as the concentration of fuel **below which** combustion will not be self-sustaining. The *upper explosive limit* (UEL) is defined as the concentration of fuel mixture that will not burn because of a lack of oxygen. Table 2-1 listed the flammability limits (LEL and UEL) for common fuels and solvents.

For example, consider that a mixture of gasoline vapors and air is at atmospheric conditions. From Table 2-1 the LEL is 1.4% by volume of gasoline vapors and the UEL is 7.6%. Any concentration of gasoline in air within these limits will support combustion. That is, once a flame has been ignited it will continue to burn. Concentrations of gasoline in air below or above these limits will not burn and can quench the flame.

Thermodynamic and Combustion Terms

In describing any combustion process, many terms are used to define heat. These terms can be divided into two categories: thermodynamic and combustion. Thermodynamic terms, applying to all systems, define the energy level, or potential heat, present in any substance. Combustion terms, initiated to aid in standardizing fuel usage calculations, are applied to heat produced by combustion methods. Because the combustion terms are specific examples of the thermodynamic terms, some overlap is involved in defining them. The following are important terms describing heat thermodynamically:

Sensible heat (H_s): Heat that causes a change in temperature when added or removed.

Latent heat (H_L): Heat given off by a vapor condensing to a liquid or gained by a liquid evaporating to a vapor, without a change in temperature. The latent heat of vaporization of water at 212°F is 970.3 Btu/lb.

Heat content or enthalpy (H): The sum total of latent and sensible heat present in a substance (gas, liquid, or solid) **minus** that contained at an arbitrary set of conditions chosen as the base or zero point. Values for various gases are listed in Table 2-2.

Table 2-2. Heat contents of various gases.

Temp (°F)	Heat content, H (Btu/lb at 1 atm)								
	O ₂	N ₂	Air	CO	CO ₂	SO ₂	H ₂	CH ₄	H ₂ O
60	0	0	0	0	0	0	0	0	0
100	8.8	9.9	9.6	10.0	8.0	5.9	137	21.0	—
200	30.9	34.8	33.6	34.9	29.3	21.4	484	76.1	—
300	53.3	59.9	57.7	59.9	52.0	37.5	832	136.4	1165
400	76.2	85.0	81.8	85.0	75.3	54.4	1182	202.1	1212
500	99.4	110.3	106.0	110.6	99.8	71.8	1532	272.6	1259
600	123.1	136.1	130.2	136.3	125.1	89.8	1882	347.8	1307
700	147.2	161.7	154.5	162.4	149.6	108.2	2233	427.4	1355
800	171.7	187.7	178.9	188.7	177.8	127.0	2584	511.2	1404
900	196.6	213.9	203.4	215.6	205.6	146.1	2935	599.2	1454
1000	221.7	240.7	235.0	242.7	233.6	165.5	3291	691.1	1505
1200	272.5	294.7	288.5	297.8	290.9	205.1	4007	886.2	1609
1400	324.3	350.8	343.0	354.3	349.7	245.4	4729	1094.1	1717
1600	377.3	407.3	398.0	407.5	416.3	286.4	5460	1313.0	1829
1800	430.7	465.0	455.0	465.3	470.9	327.8	6198	1542.6	—
2000	484.0	523.8	513.0	523.8	532.8	369.1	6952	—	—
2200	539.3	583.2	570.7	583.3	596.1	411.1	7717	—	—
2400	594.4	642.3	628.5	643.0	659.2	452.7	8490	—	—
2600	649.0	702.8	687.3	703.2	723.2	495.2	9272	—	—
2800	702.8	763.1	746.6	771.3	787.4	537.5	10060	—	—
3000	758.6	824.1	806.3	832.6	852.0	580.0	10870	—	—
3200	816.4	885.8	866.0	894.0	916.7	622.5	11680	—	—
3400	873.4	947.6	925.9	956.0	981.6	665.0	12510	—	—
3600	931.0	1010.3	986.1	1018.3	1047.3	707.5	13330	—	—

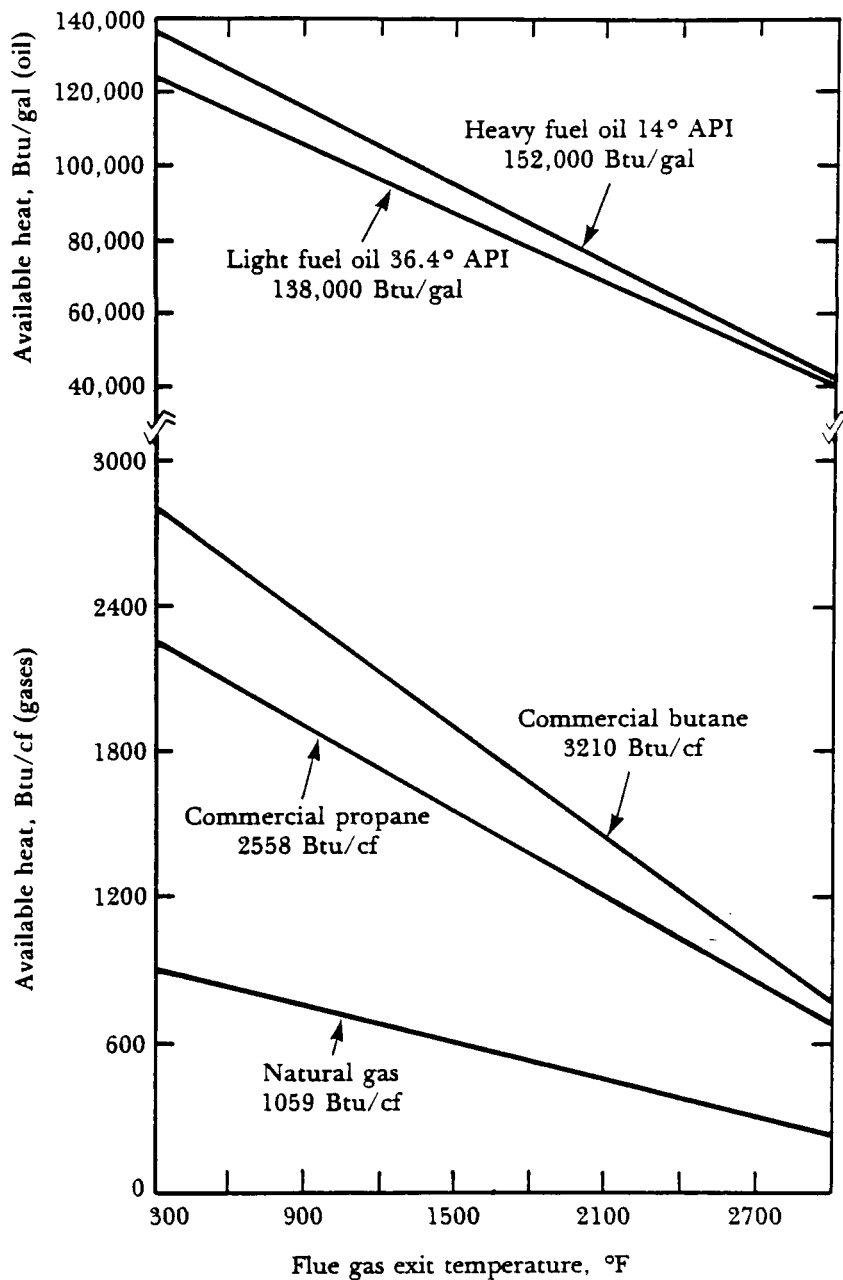
Source: North American Combustion Handbook, 1952.

Some useful terms describing heat produced by combustion of a fuel are:

Gross heating value (HV_G): The total heat obtained from the complete combustion of a fuel that is at 60°F when combustion starts, and the combustion products of which are cooled to 60°F before the quantity of heat released is measured. Constant pressure, normally 101.3 kPa (1 atmosphere) is maintained throughout the entire combustion process. Gross heating values are also referred to as *total*, or *higher, heating values* (HHV).

Net heating value (HV_N): The gross heating value minus the latent heat of vaporization of the water formed by the combustion of the hydrogen in the fuel. For a fuel containing no hydrogen, the net and gross heating values are the same.

Available heat (H_A): The gross quantity of heat released within a combustion chamber minus (1) the sensible heat carried away from the dry flue gases and, (2) the latent heat and sensible heat carried away in water vapor contained in the flue gases. The available heat represents the net quantity of heat remaining for useful heating. Figure 2-2 shows the available heat from the complete combustion (no excess air) of various fuels at various flue gas temperatures.



Source: North American Combustion Handbook, 1965.

Figure 2-2. Available heat for some typical fuels (referred to 60°F).

Since all of the previous terms describe heat, they all are expressed in units of Btu/lb. Figure 2-3 illustrates the interrelation of these terms.

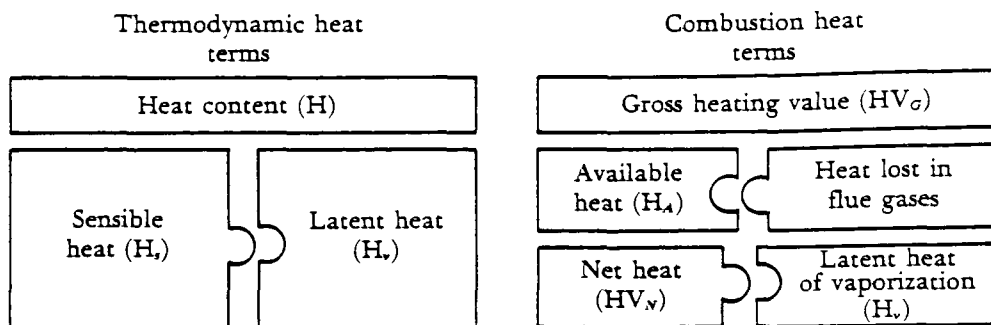


Figure 2-3. Heat terms.

Depending on the user, the above terms can also have more than one definition. For example, a laboratory chemist may describe latent heat as the energy used in the chemical combustion of a fuel to carbon dioxide and water; while a boiler operator may describe latent heat as the difference between the gross and net heating values.

Another important term used in performing combustion calculations is the *specific heat*, C_p , of a substance. Specific heat is defined as the amount of heat required to raise 1 pound of a substance 1 degree fahrenheit. Specific heat is given as Btu/lb·°F in English units. Specific heat depends on temperature.

Heat Balance

To design or review the operating performance of a boiler, a heat balance of the system is usually determined. The first law of thermodynamics states that energy entering a system must leave the system or be stored in some manner. In a boiler the heat energy into the system is therefore equal to the heat energy out of the system.

$$\text{Heat in (sensible + HHV)} = \text{heat out (sensible + latent + available)}$$

In order to compute a heat balance, a number of parameters must be measured including fuel heat content and quantity burned, air quantity, flue gas losses, and boiler losses.

Fuel Characteristics

The chemical makeup and heat content of the common fuels burned in boilers vary depending on the type of fuel used. Fossil fuels—natural gas, fuel oil, and coal—are most often used in boilers. Natural gas consists of varying amounts of methane (CH_4), ethane (C_2H_6), ethylene (C_2H_4), carbon dioxide (CO_2), carbon monoxide (CO), hydrogen (H_2), oxygen (O_2), nitrogen (N_2), and hydrogen sulfide (H_2S), depending on where the gas comes from.

The heat content of natural gas varies from approximately 950 to 1150 Btu/ft³ of gas. The analyses and heat contents of various samples of natural gas are given in Table 2-3.

Table 2-3. Various samples of natural gas.

Sample no. source of gas	1 Pa.	2 So. Cal.	3 Ohio	4 La.	5 Okla.
Analyses					
Constituents, % by vol					
H ₂ Hydrogen	—	—	1.82	—	—
CH ₄ Methane	83.40	84.00	93.33	90.00	84.10
C ₂ H ₄ Ethylene	—	—	0.25	—	—
C ₂ H ₆ Ethane	15.80	14.80	—	5.00	6.70
CO Carbon monoxide	—	—	0.45	—	—
CO ₂ Carbon dioxide	—	0.70	0.22	—	0.80
N ₂ Nitrogen	0.80	0.50	3.40	5.00	8.40
O ₂ Oxygen	—	—	0.35	—	—
H ₂ S Hydrogen sulfide	—	—	0.18	—	—
Ultimate, % by wt					
S Sulfur	—	—	0.34	—	—
H ₂ Hydrogen	23.53	23.30	23.20	22.68	20.85
C Carbon	75.25	74.72	69.12	69.26	64.84
N ₂ Nitrogen	1.22	0.76	5.76	8.06	12.90
O ₂ Oxygen	—	1.22	1.58	—	1.41
Specific gravity (rel to air)	0.636	0.636	0.567	0.600	0.630
Higher heat value					
Btu/cu ft@60°F and 30 in. Hg	1,129	1,116	964	1,002	974
Btu/lb of fuel	23,170	22,904	22,077	21,824	20,160

Source: Babcock and Wilcox, 1978.

Fuel oils, refined from crude oil, contain varying amounts of carbon, hydrogen, nitrogen, oxygen, ash, and sulfur. Fuel oils are graded according to gravity and viscosity, the lightest being No. 1 and the heaviest No. 6. Grades 5 and 6 usually need to be heated before they can be adequately pumped to and burned in the burner. The heat content of fuel oil varies from approximately 18,000 to 20,000 Btu/lb. The analyses and heat contents of some fuel oils are listed in Table 2-4.

It is common practice to report the components of coal using either a *proximate* analysis or an *ultimate* analysis. In the proximate analysis, the amount of moisture, volatile matter, fixed carbon, and ash in the coal are determined. In the ultimate analysis, the amount of carbon, hydrogen, oxygen, nitrogen, sulfur, and ash are determined. The ultimate analysis is useful in computing the stoichiometric, or theoretical, air requirements by using Equation 2-6.

$$(\text{Eq. 2-6}) \quad \text{Theoretical air} = 11.53 C + 34.34 \left(H_2 - \frac{O_2}{8} \right) + 4.29 S$$

Coal is ranked by the amount of fixed carbon, the hardness, and the calorific value, or heat content. Peat and lignite are the softest coals, sub-bituminous and bituminous are harder, and anthracite is the hardest. The analyses and calorific values of some selected coals are given in Table 2-5.

Table 2-4. Analyses of typical fuel oils.

Grade of fuel oil	Sample no. 1	Sample no. 2	Sample no. 4	Sample no. 5	Sample no. 6
Weight, percent					
Sulfur	0.01-0.5	0.05-1.0	0.2-2.0	0.5-3.0	0.7-3.5
Hydrogen	13.3-14.1	11.8-13.9	(10.6-13.0)*	(10.5-12.0)*	(9.5-12.0)*
Carbon	85.9-86.7	86.1-88.2	(86.5-89.2)*	(86.5-89.2)*	(86.5-90.2)*
Nitrogen	Nil-0.1	Nil-0.1	—	—	—
Oxygen	—	—	—	—	—
Ash	—	—	0-0.1	0-0.01	0.01-0.5
Gravity					
Deg API ¹	40-44	28-40	15-30	14-22	7-22
Specific	0.825-0.806	0.887-0.825	0.966-0.876	0.972-0.922	1.022-0.922
Lb per gal	6.87-6.71	7.39-6.87	8.04-7.30	8.10-7.68	8.51-7.68
Pour point, °F	0 to -50	0 to -40	-10 to +50	-10 to +80	+15 to +85
Viscosity					
Centistokes@100°F	1.4-2.2	1.9-3.0	10.5-65	65-200	260-750
Saybolt Universal Scale@100°F	—	32-38	60-300	—	—
Saybolt Furol Scale@122°F	—	—	—	20-40	45-300
Water and sediment, vol %	—	0-0.1	tr to 1.0	0.05-1.0	0.05-2.0
Heating value					
Btu per lb, gross (calculated)	19,670-19,860	19,170-19,750	18,280-19,400	18,100-19,020	17,410-18,990

*Estimated.

¹The API degree scale is commonly used in specifying various grades of oil. It is inversely related to the specific gravity at 60°F:

$$\text{Degrees API} = \frac{141.5}{\text{Sp. gr.}@60^\circ\text{F}} - 131.5$$

Source: Babcock and Wilcox, 1978.

Table 2-5. Typical analyses of wood, peat, and coal.

Kind of fuel	Proximate analysis				Ultimate analysis					Calorific value (Btu/lb)
	Moisture	Volatile matter	Fixed carbon	Ash	Sulfur	Hydrogen	Carbon	Nitrogen	Oxygen	
Wood	—	—	—	—	—	6.25	49.50	1.10	43.15	5,800
Peat	56.70	26.14	11.17	5.99	0.64	8.33	21.03	1.10	62.91	3,586
Lignite	34.55	35.34	22.91	7.20	1.10	6.60	42.40	0.57	42.13	7,090
Subbituminous	24.28	27.63	44.84	3.25	0.36	6.14	55.28	1.07	33.90	9,376
Bituminous	3.24	27.13	62.52	7.11	0.95	5.24	78.00	1.23	7.47	13,919
Semibituminous	2.03	14.47	75.31	8.19	2.26	4.14	79.97	1.26	4.18	14,081
Semianthracite	3.38	8.47	76.65	11.50	0.63	3.58	78.43	1.00	4.86	13,156
Anthracite	2.80	1.16	88.21	7.83	0.89	1.89	84.36	0.63	4.40	13,298

Source: Woodruff and Lammer, 1977.

Boiler Efficiency

Boiler efficiency is defined as the amount of heat absorbed by the water divided by the amount of heat contained in the fuel being burned. In equation form, this is

$$\begin{aligned} \text{(Eq. 2-7) Boiler efficiency} &= \frac{\text{heat absorbed by boiler fluid}}{\text{heat contained in fuel}} \times 100\% \\ &= \frac{\text{steam flow rate (heat of steam - heat of feedwater)}}{(\text{weight of fuel})(\text{HHV of fuel})} \times 100 \\ &= \frac{\dot{m}_s(h_s - h_{fw})}{\dot{m}_f(\text{HHV})} \times 100 \end{aligned}$$

Where: \dot{m}_s = mass flow rate of steam, lb/hr
 \dot{m}_f = mass flow rate of fuel, lb/hr
 h_s = enthalpy of steam leaving boiler, Btu/lb
 h_{fw} = enthalpy of water entering the boiler, Btu/lb
HHV = higher heating value of fuel, Btu/lb

To calculate boiler efficiency using Equation 2-7, the quantity of energy input to the boiler and output from the boiler are measured. These measurements can be taken by using flowmeters, thermometers, or thermocouples, and pressure gauges. Calculation inaccuracies can occur because of inaccuracies of the measuring devices. All instruments should be calibrated frequently. The results are usually checked by calculating a heat balance for the system. Measurements to be taken are:

Feedwater entering the boiler

\dot{m}_{fw} = boiler feedwater flow rate

T_{fw} = feedwater temperature

p_{fw} = feedwater pressure

Steam leaving the boiler

\dot{m}_s = steam flow rate

$= \dot{m}_{fw} - \dot{m}_b$ (feedwater flow rate - blowdown flow rate)

T_s = steam temperature

p_s = steam pressure

Fuel entering boiler

\dot{m}_f = fuel flow rate

T_f = fuel temperature

p_f = fuel pressure

HHV = fuel higher heating value

Heat Losses

Not all of the energy contained in fuel is converted to heat and absorbed by the boiler equipment. Some of this energy is lost. Some fuel may leave as unburned carbon if combustion is not complete. Moisture in the fuel accounts for some heat loss. Hydrogen in the fuel is converted to water when burned, making this another heat loss. Moisture in the air also contributes to heat loss. One of the largest heat losses is from the dry flue gas because the stack temperature is much higher than the temperature of air (ambient) used for combustion. Stack temperature is usually maintained at greater than 300°F to prevent moisture and acids in the flue gas from condensing on ductwork, fans, or stack walls.

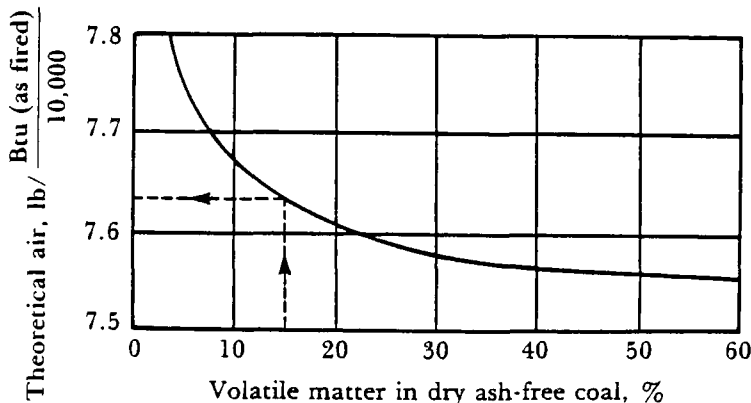
One method to calculate boiler efficiency is the *Btu method* (Babcock and Wilcox, 1978). The amount of air required per pound of fuel burned is calculated using the theoretical air required per 10,000 Btu heat value of the fuel. Values of theoretical air (lb of air/lb of fuel) can be obtained by multiplying the heat content of the fuel as fired, (Btu/10,000)/lb of fuel, by the theoretical air required per 10,000 Btu, lb air/(Btu/10,000).

If the ultimate analysis of a fuel is known, the value of theoretical dry air expressed as lb air/(Btu/10,000) is calculated using Equation 2-8.

$$\text{(Eq. 2-8)} \quad \text{Theoretical dry air} = 144 \left(\frac{8 C + 24 \left(H_2 - \frac{O_2}{8} \right) + 3 S}{\text{Btu/lb}} \right)$$

Where: C = carbon, % by weight
 H_2 = hydrogen, % by weight
 O_2 = oxygen, % by weight
 S = sulfur, % by weight
 Btu/lb = heat value of the fuel.

Equation 2-8 should **only** be used when the ultimate analysis of the fuel is given and when the correct heating value of the fuel is known. When the proximate analysis of coal is known, Figure 2-4 can be used to obtain the theoretical air in lb per 10,000 Btu.



Source: Babcock and Wilcox, 1978.

Figure 2-4. Theoretical air in lb per 10,000 Btu heat value of coal with a range of volatile matter.

Example 2-2

From the proximate analysis of a type of coal given below, calculate theoretical air in units of lb of air/lb of fuel. The excess air is 20%. (Source: Babcock and Wilcox, 1978.)

Bituminous coal proximate analysis as fired, % by weight

Moisture	12.0
Volatile matter	25.8
Fixed carbon	46.2
Ash	16.0
Btu/lb	10,900

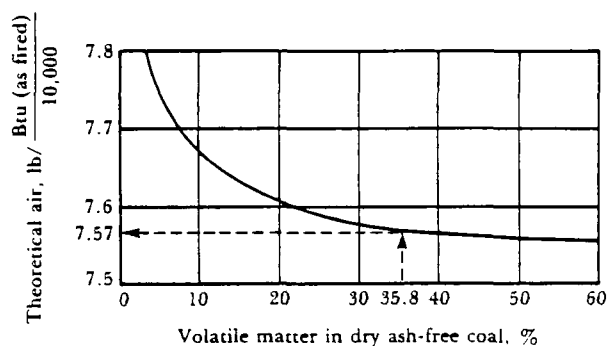
Solution:

1. The volatile matter on a dry ash free basis is:

$$\frac{\text{volatile matter}}{\text{volatile matter} + \text{carbon}} \times 100\% = \frac{25.8}{25.8 + 46.2} \times 100\% = 35.8\%$$

2. Using Figure 2-4, and the abscissa of 35.8, move up to the line and read the value on the ordinate.

$$\text{lb of air} / 10,000 = 7.57$$



3. The required total dry air including 20% excess air is:

$$7.5 \text{ lb of air} \times \frac{\text{excess air} + 100}{100} \times \frac{\text{heating value of fuel}}{10,000 \text{ Btu}} = 7.5 \times \frac{120}{100} \times \frac{10,900}{10,000} = 9.81 \text{ lb of air/lb of fuel}$$

Table 2-6 is an example of combustion calculations using the Btu method. This table is taken from *Steam/Its Generation and Use* by Babcock and Wilcox.

Bituminous coal is the fuel used in the calculations in Table 2-6. Examples for fuel oil and natural gas can be found in *Steam/Its Generation and Use*.

L I N E	Table 2-6. Combustion calculations. Based on quantities per 10,000 Btu fuel input				L I N E
	Conditions by test or specification			Date	
1	Fuel— <i>Bituminous Coal, Virginia</i>				a
2	Analysis As Fired				
3	Ultimate, % by Wt	Proximate, % by Wt	Total air	% 120	b
4	C 80.31	Moisture 2.90	Air temperature to heater	F 80	c
5	H ₂ 4.47	Volatile 22.05	Air temperature from heater	F 350	d
6	S 1.54	Fixed carbon 68.50	Flue gas temperature leaving unit	F 280	e
7	O ₂ 2.85	Ash 6.55	H ₂ O per lb dry air	lb 0.013	f
8	N ₂ 1.38	100.00			g
9	H ₂ O 2.90		Unburned fuel loss	% 0.4	h
10	Ash 6.55		Unaccounted loss	% 1.5	i
11	100.00		Radiation loss (ABMA), Figure 2-5	% 0.8	j
12	Btu per lb, as fired, 14,100				k
13	Quantities per 10,000 Btu Fuel Input				13
14	Fuel burned, $[100(100 - \text{line } 10) \div \text{line } 12] - .007 \times \text{line } h$			lb 0.66	14
15	Dry air, line b [(value from Fig. 4, Table 11 or Eq. 6) - .08 × line h]			lb 9.11	15
16	H ₂ O in air, line 15 × line f = 9.11 × 0.013			lb 0.12	16
17	Wet gas, total, lines (14 + 15 + 16)			lb 9.89	17
18	H ₂ O in fuel, $100(8.94 \times \text{line } 5 + \text{line } 9) \div \text{line } 12$, or Table 11			lb 0.30	18
19	H ₂ O in flue gas, total, line 16 + line 18			lb 0.42	19
20	H ₂ O in flue gas, total, in percent, $(\text{line } 19 \div \text{line } 17) \times 100$			% 4.31	20
21	Dry gas, total, line 17 - line 19			lb 9.47	21
22	Losses per 10,000 Btu Fuel Input				22
23	Unburned fuel, $10,000 \times \text{line } h \div 100$			Btu 40	23
24	Unaccounted, $10,000 \times \text{line } i \div 100$			Btu 150	24
25	Radiation, $10,000 \times \text{line } j \div 100$			Btu 80	25
26	Latent Heat, H ₂ O in fuel, $1040 \times \text{line } 18$			Btu 312	26
27	Sensible heat, flue gas, line 17 × Btu from Fig. 1 @ line e and line 20 = 9.89 × 50			Btu 495	27
28	Total losses, lines (23 + 24 + 25 + 26 + 27)			Btu 1077	28
29	Total losses in percent, $(\text{line } 28 \div 10,000) \times 100$			% 10.8	29
30	Efficiency, by difference, $100 - \text{line } 29$			% 89.2	30
31	Quantities per 10,000 Btu Fuel Input Combustion temperature, adiabatic				31
32	Heat input from fuel			Btu 10,000	32
33	Heat input from air, lines (15 + 16) × Btu from Fig. 8 @ line d temp			Btu 612	33
34	Heat input, total, lines 32 + 33			Btu 10,612	34
35	Less latent heat loss, H ₂ O in fuel, line 26			Btu -312	35
36	Heat available, maximum			Btu 10,300	36
37	Less (lines 24 + 25) × 0.5*			Btu -115	37
38	Heat available, line 36 - line 37			Btu 10,185	38
39	Heat available per lb of flue gas, line 38 ÷ line 17			Btu 1021	39
40	Adiabatic temperature, from Fig. 1 for lines 20 & 39			F 3513	40

*Note: It is customary to reduce the maximum heat available, line 36, by from 1/3 to 1/2 of the unaccounted plus radiation losses, on the assumption that a portion of these losses occurs in the combustion zone.

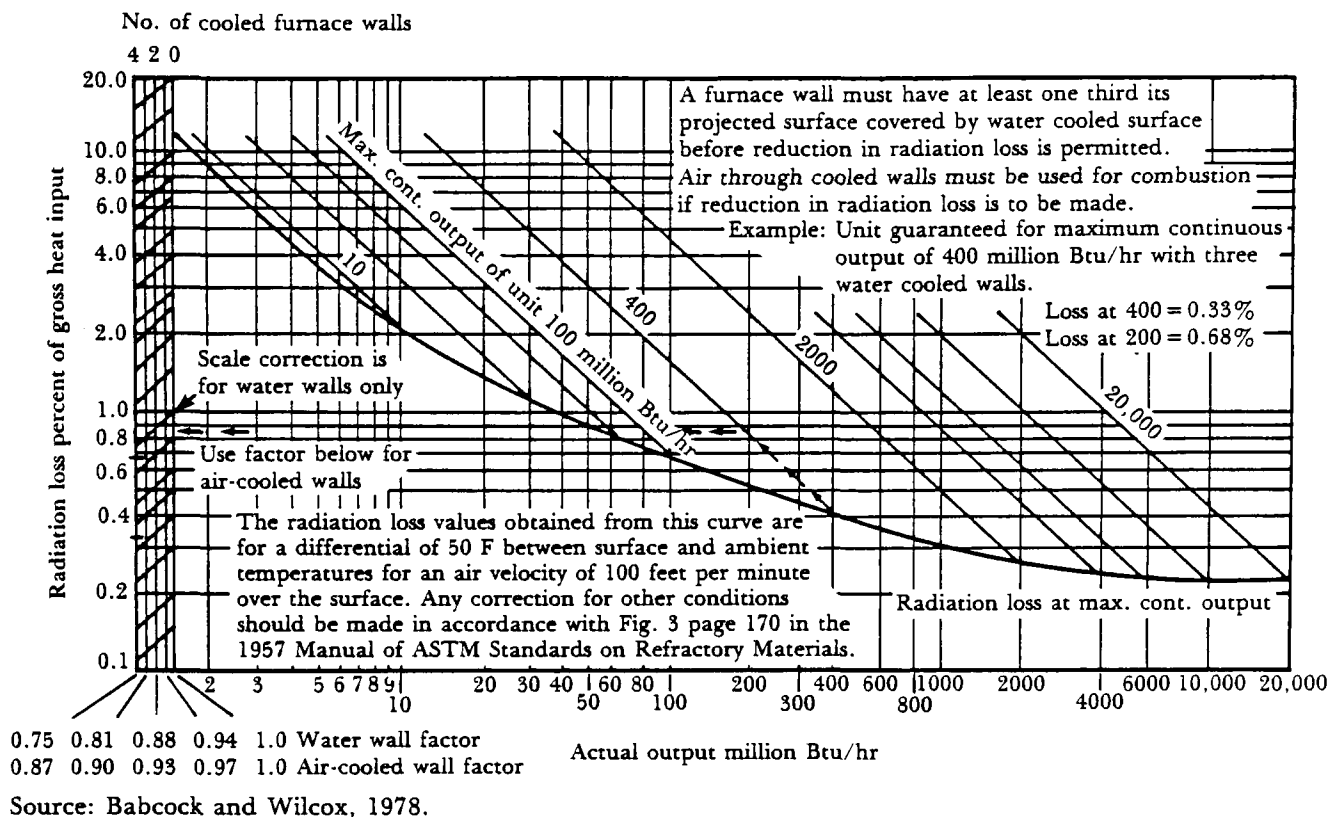


Figure 2-5. Radiation losses.

Review Exercise	
1. To achieve complete combustion of an organic compound, a sufficient supply of oxygen must be present to convert all of the carbon to CO ₂ . The quantity of oxygen is called _____.	•
2. In boilers, more than the stoichiometric amount of air is required to ensure complete combustion. This volume of air is referred to as _____.	1. stoichiometric or theoretical amount
3. An orsat apparatus is used to measure the concentration of _____ in the flue gas. a. particulate matter b. CO ₂ and O ₂ only c. CO ₂ , H ₂ O, and O ₂ d. CO ₂ , O ₂ , and CO	2. excess air
	3. d. CO ₂ , O ₂ , and CO

4. The _____ is defined as the concentration of fuel mixture that will not burn because of a lack of oxygen. a. low amount of excess air b. lower explosive limit (LEL) c. upper explosive limit (UEL) d. sensible heat factor	
5. The amount of heat given off when a vapor condenses to a liquid or gained when a liquid evaporates to a vapor without a change in temperature is called a. sensible heat. b. latent heat. c. enthalpy. d. gross heating value.	4. c. upper explosive limit (UEL)
6. The _____ is equal to the gross heating value minus the latent heat of vaporization of water formed by the combustion of hydrogen contained in a fuel. a. sensible heat (H_s) b. enthalpy (H) c. net heating value (HV_n)	5. b. latent heat.
7. True or False? Natural gas consists of varying amounts of methane, ethane, ethylene, hydrogen, and other gases.	6. c. net heating value (HV_n)
8. Fuel oil(s) _____ usually need to be heated before they can be adequately pumped to and burned in a burner. a. No. 1 and No. 2 b. No. 1 c. No. 5 and No. 6 d. No. 6	7. True
9. In the _____, the amount of moisture, volatile matter, fixed carbon, and ash in the coal are determined. a. proximate analysis b. ultimate analysis c. heat balance	8. c. Nos. 5 and 6
10. True or False? Bituminous coal is harder, has a higher heat content and contains more volatile matter than does anthracite coal.	9. a. proximate analysis
	10. False. The reverse is true for each criteria.

11. In a boiler, which of the following are heat losses? a. unburned carbon b. moisture in the fuel c. hydrogen in the fuel d. moisture in the combustion air e. dry flue gas f. a., b., and d. only g. all of the above	
	11. g. all of the above

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Lesson 3

Supplying Air and Fuel

Lesson Goal and Objectives

Goal

To familiarize you with the methods of introducing fuel and air into a boiler.

Objectives

Upon completing this lesson, you should be able to—

1. identify the location where primary, secondary, and tertiary air are brought into the furnace,
2. briefly describe six types of coal-fired boilers: hand-fired, chain and traveling-grate stoker, underfeed stoker, spreader stoker, pulverized, and fluidized bed, and
3. briefly describe how fuel oil and gas are burned in a boiler.

Introduction

Boilers are carefully designed to burn the proper amount of air and fuel in the firebox of the furnace. Air enters the furnace through burners, registers, or ports depending on the design of the unit. Fuel enters the furnace through burners, grates, or fuel beds. To achieve complete combustion air and fuel must be intimately mixed. Combusted fuel produces hot flue gas that moves through the boiler transferring heat to the boiler tubes. Flue gas is most often pushed through or pulled through the boiler by a fan before exiting through a stack or chimney. This lesson will look at how air and fuel are introduced into a boiler.

Combustion Air

As stated in Lesson 2, a stoichiometric amount of air is needed for combustion. Actually, a small amount of excess air is needed to ensure complete combustion. Air enters the furnace at different locations depending on the size, sophistication, and design of the boiler. In small boilers, combustion air enters through openings in the burner or through the openings in the bottom of the furnace, called registers. In larger boilers, the primary air used to support combustion is occasionally brought in through the burners, through openings in the furnace walls, or through openings in the grates. Occasionally boilers will be equipped with openings that provide

secondary air for combustion. Secondary air helps combust any volatile gases produced in the initial combustion phase. Some boilers use burners that have openings for primary, secondary, and tertiary air. Others bring secondary air into the furnace through a windbox. A forced-draft fan moves air through the windbox into openings in the furnace wall. Secondary and tertiary air are used in large boilers to ensure that all of the fuel is completely burned.

Draft

Boilers are usually equipped with chimneys to produce the draft necessary to move combustion air into the furnace and to discharge the combustion products, or flue gas, to the atmosphere. Just as in a home fireplace, the draft must be produced high enough to provide enough air to burn the fuel without causing it to smoke and to move the flue gas up the chimney. A natural draft boiler system uses chimneys to move gases through the system.

Natural-draft chimneys are generally used on small, simple boilers that do not use economizers and air preheaters. Larger boilers that use heat-recovery equipment and air pollution control devices must use fans to move air through the system because of the high draft losses produced by this add-on equipment.

Fans applied to boiler systems fall into three categories—forced draft, induced draft, and balanced draft. In a forced-draft system, a fan pushes air into the furnace, causing combustion products to flow through the boiler and from the stack. The boiler is maintained at a pressure above atmospheric pressure to force the flue gas through it. These boilers are also called pressurized furnaces. In an induced-draft system, a fan is located after the boiler, pulling the air into the furnace, through the boiler, and from the stack. The boiler is maintained at a pressure slightly below atmospheric pressure. In a balanced-draft system, a forced draft fan pushes air into the furnace and an induced-draft fan (or chimney) produces a draft to pull flue gas through the boiler to exit from the stack. This boiler is maintained at a pressure slightly less than atmospheric pressure, usually from 0.05 to 0.10 in. of water.

Boiler systems generally use centrifugal fans. Gas is introduced into the center of a revolving wheel, or rotor, and exits at a right angle (90°) to the rotation of the blades (Figure 3-1). Centrifugal fans are classified by the shape of the blades used in the fan. The forward-curved fans (Figure 3-1a) have blades that are curved toward the direction of the wheel rotation. The blades are smaller and spaced closer together than are the blades of other centrifugal fans. These fans are not used to move flue gas containing dust or sticky materials. They are generally used only as forced-draft fans. Backward-curved fans (Figure 3-1b) have blades that are curved away from the direction of the wheel rotation. The blades clog when the fan is used to move flue gas containing dust or sticky fumes. They may be used on the clean-air discharge of air pollution control devices or to provide clean combustion air for boilers. Radial fans (Figure 3-1c) use straight blades that are attached to the wheel of the rotor. These fans are built for high mechanical strength and can be easily repaired. Fan blades may be constructed of alloys or coated steel to help prevent

deterioration when handling abrasive and corrosive flue gas. Radial fans are frequently used for induced-draft systems—particularly with air pollution control devices. Airfoil fans (Figure 3-1d) have thick teardrop-shaped blades that are curved away from the wheel rotation. Airfoil fans can also clog when handling dust or sticky materials.

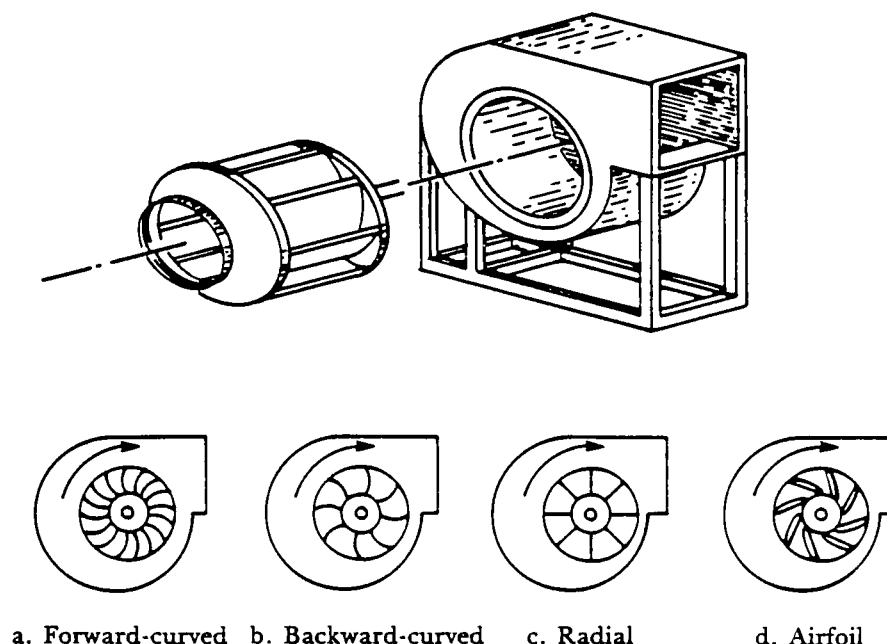


Figure 3-1. Centrifugal fans.

Coal-Fired Boilers

Coal is fed into a boiler and then burned in a number of ways depending on the design and size of the boiler. The oldest and simplest method is that of hand firing. When coal is stoked, it travels on a moving grate or is fed onto a grate by a moving ram or spreader. Many large boilers *pulverize* coal into fine powder and then feed it into the furnace through burners. Coal-fired boilers will vary depending on the sophistication of the system and on the type of coal that is burned.

Hand-Fired

Hand firing is seldom used today, only in very small boilers used for heating or in small industrial processes. Coal is fed manually onto a cast iron grate by a fireman. The grate is sloped slightly towards the rear of the furnace to aid the fireman in moving the coal to the furnace rear. The boiler size is limited to 6 or 7 ft long because of the physical limitation of the fireman to maintain the fire. The actual area of the grate depends on the heating surface of the boiler and the kind of fuel burned. To start the boiler, a layer of approximately 3 to 4 inches of coal is shoveled by hand onto the grate. Wood shavings are placed on top of the coal bed. The bed

is usually ignited by using oily rags. Once the coal bed has ignited, coal can be fed onto the burning bed to keep the fire going. Most of the hand-fired units have been replaced by more sophisticated designs.

Stoker-Fired

A number of stokers are in use today. They differ in the way coal is fed onto the grate, and the way ash is removed from the grate. Stokers can be grouped into three major categories: underfeed stokers, overfeed stokers, and spreader stokers.

Underfeed Stokers

In an underfeed stoker coal is fed into the furnace through long troughs called retorts. As the name implies, coal is forced up from underneath the burning fuel bed. Air comes in through openings in the grate, called tuyères (pronounced twēē-yars). The smallest underfeed stokers use single or double retorts. A screw feeder on a mechanical ram forces the coal through the length of the retort and upward. Ash is usually discharged into ash pits by side-dumping grates. Figure 3-2 shows a single-retort underfeed stoker. Single- and double-retort underfeed stokers fire boilers that can produce 3000 to 30,000 pounds of steam per hour.

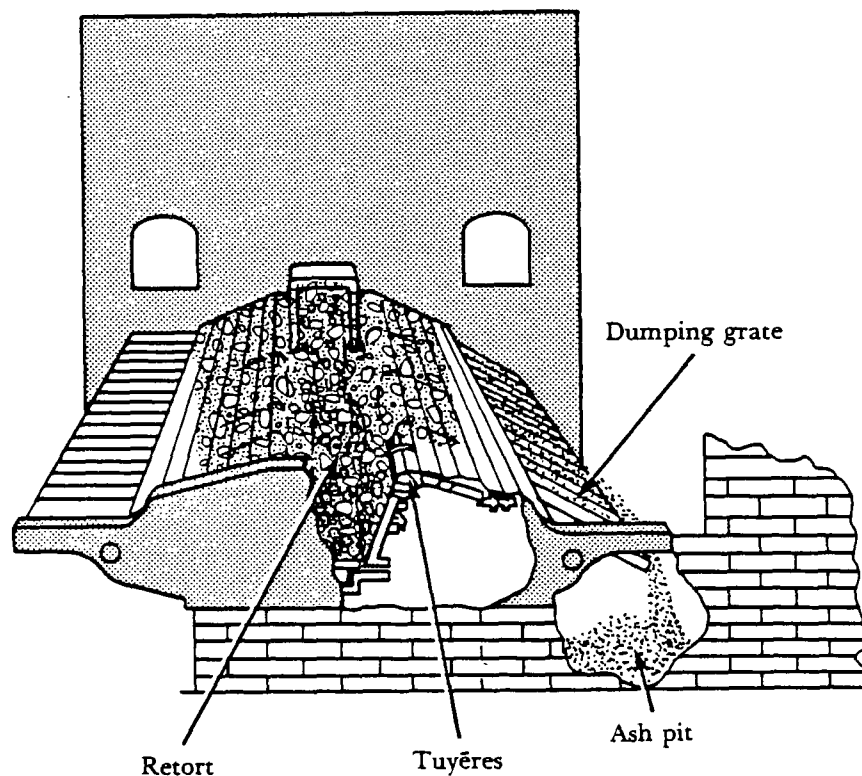


Figure 3-2. Single-retort underfeed stoker.

Some retorts use grates that move up and down to break up the coke that forms as coal burns and to also provide good air distribution through the burning fuel bed. Most modern underfeed stokers use overfire-air jets, also called secondary airports, to mix the volatile gases with air and burn them.

In underfeed stokers using feed rams, the ram forces coal from a hopper into the retort. During normal operation, green, or raw, coal is continually pushed out over the grate tuyères. The burning coal slowly moves from the retort over grates toward the sides of the furnace. After combustion is completed, ashes are dumped into an ash pit located at the bottom of the furnace.

Larger underfeed stokers use multiple retorts, sometimes as many as twelve. To aid in moving the coal and ash through the furnace, these retorts are inclined 25° to 30° from the rams toward the ash-discharge end of the furnace. The multiple-retort stoker consists of single retorts placed side by side with tuyères between each of them. Each retort is equipped with a primary ram to feed coal from a hopper. The fuel is moved slowly toward the furnace rear and at the same time forced up over the tuyères by secondary (distribution) pushers or by moving the bottom of the retort. Most of the combustion air comes in through tuyères. However, some overfire air is used to ensure that the fuel is completely burned. Ash is discharged at the rear of the furnace by dump grates, or plates. Dump grates are operated by air or steam cylinders. Ash falls from the dump grates into an ash pit where water sprays are used to cool the ash. Figure 3-3 shows a multiple-retort underfeed stoker. These units are used in boilers that produce 20,000 to 500,000 pounds of steam per hour.

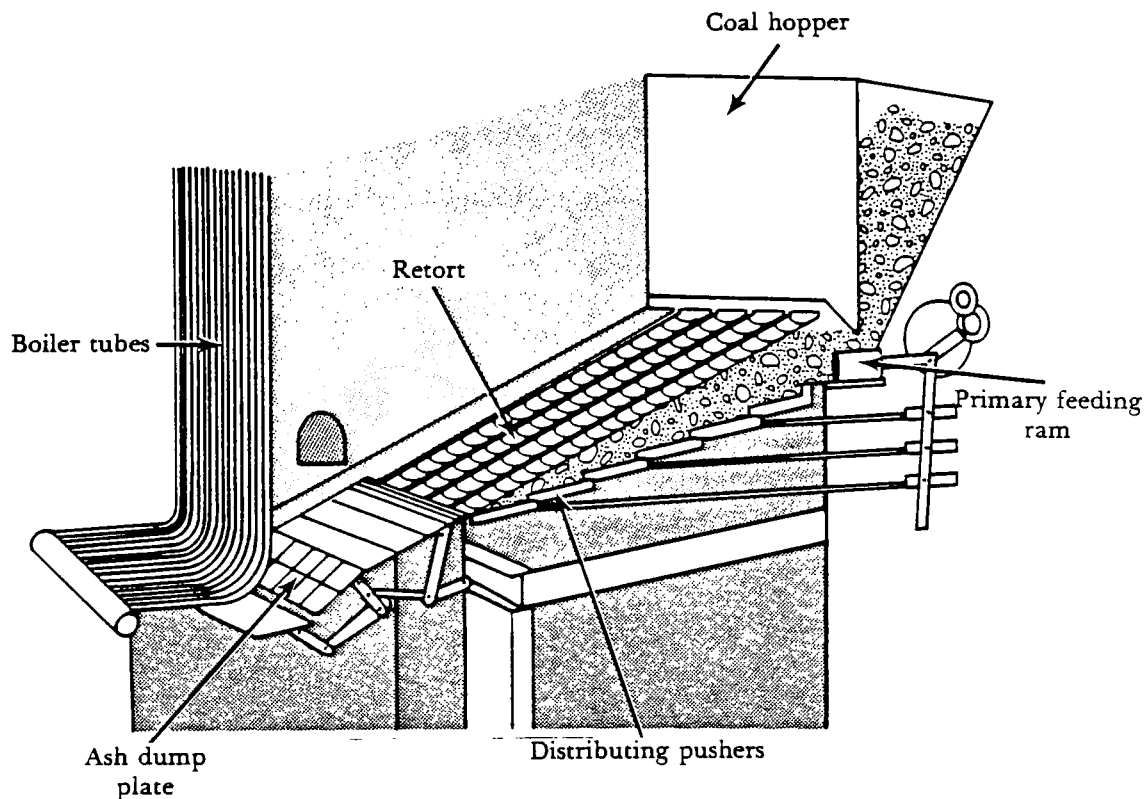


Figure 3-3. Multiple-retort underfeed stoker.

Underfeed stokers can suitably burn both anthracite and bituminous coals and are especially good for burning high-volatile coals. Burning low-ash coal may result in excessive temperatures on the grate and consequently high maintenance. In addition, if the ash in the coal fuses at a low temperature clinkers can form and clog the openings in the tuyères. Underfeed stokers are very responsive to changes in steam demand because the fuel bed on the grate is very thick. An increase in airflow through the bed quickly increases the heat in the furnace when the need for steam increases. Conversely, if the steam demand drops, the airflow through the bed can be decreased resulting in a lower amount of heat in the furnace.

Overfeed Stokers

In overfeed stokers, coal is fed onto a grate from hoppers. Three overfeed stokers are called the chain grate, traveling grate, and vibrating grate.

The chain-grate stoker uses a continuously moving grate constructed of closely fitted links of steel and chrome-cast iron. Coal is deposited onto one end of the grate from a coal hopper. The coal depth, regulated by a gate, ranges from 4 to 12 inches thick. Coal is burned as the grate moves through the furnace at less than 30 ft/hr. Ash is continuously dumped into an ash pit located at the rear of the furnace. Figure 3-4 shows a typical chain-grate stoker.

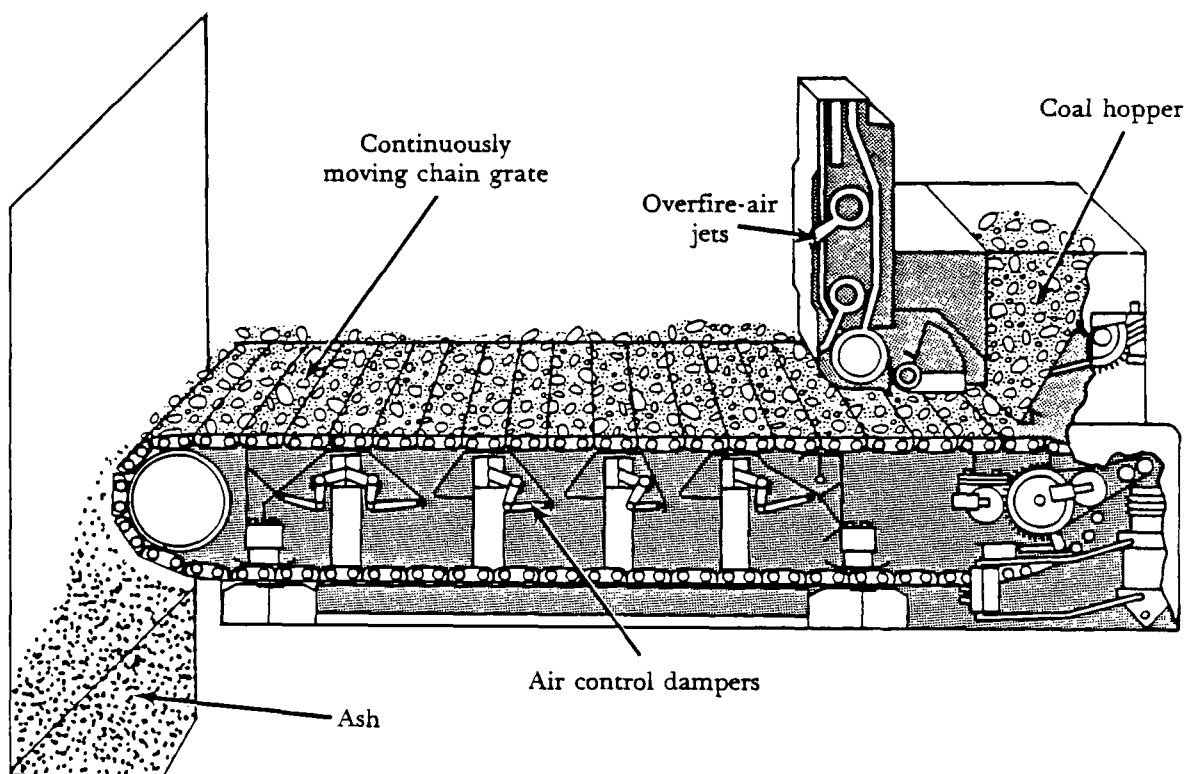


Figure 3-4. Chain-grate stoker.

The traveling-grate stoker differs from the chain-grate stoker only in the type of grate used. The traveling grate is made of steel bars, or links attached to separate carrier chains. Generally, two carrier chains support and drive each grate. Figure 3-5 shows a traveling-grate stoker.

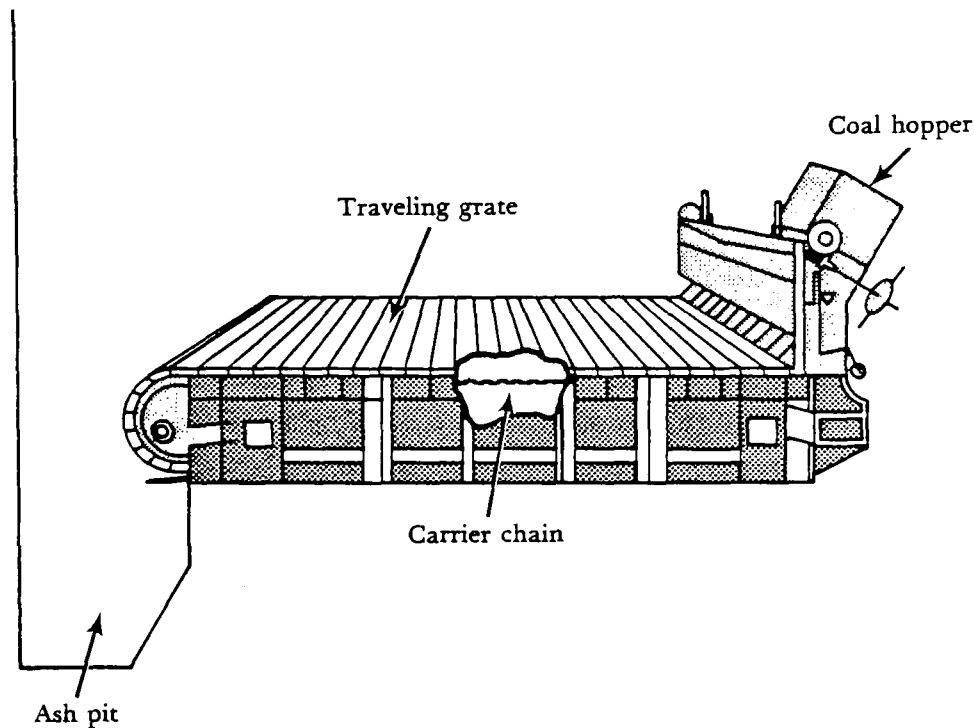


Figure 3-5. Traveling-grate stoker.

In both traveling-grate and chain-grate stokers, air enters the furnace through openings in the grates. The amount of air is manually controlled by the stoker operator. These units also use overfire-air jets located in the front wall of the furnace to mix the volatile gases with air for more complete combustion. Chain-grate and traveling-grate stokers are used on boilers that can produce as much as 200,000 pounds of steam per hour.

The vibrating-grate stoker, shown in Figure 3-6, uses vibration and gravity to move coal through the furnace. The grate is made of cast-iron blocks attached to water-cooled tubes. The water-cooled grate is tied into the boiler-circulating system. Cooling the grate allows the burning of low ash coals without overheating the grate. As with traveling-grate and chain-grate stokers, coal is fed from a hopper and the fuel bed depth is regulated by a gate. The vibrating force is provided by a generator located at the front of the stoker underneath the coal hopper. The grate is vibrated for approximately 5 seconds every 2 minutes. The interval and duration of the vibration is automatically controlled. Ash is discharged into an ash pit located in the rear of the furnace. The vibrating stoker has individually controlled air sections

underneath the grate to supply air for the varying changes in the boiler output. The boiler often has a rear arch to direct any volatile gases in the burnout zone back into the active combustion zone. These units also have overfire-air jets located in the front wall.

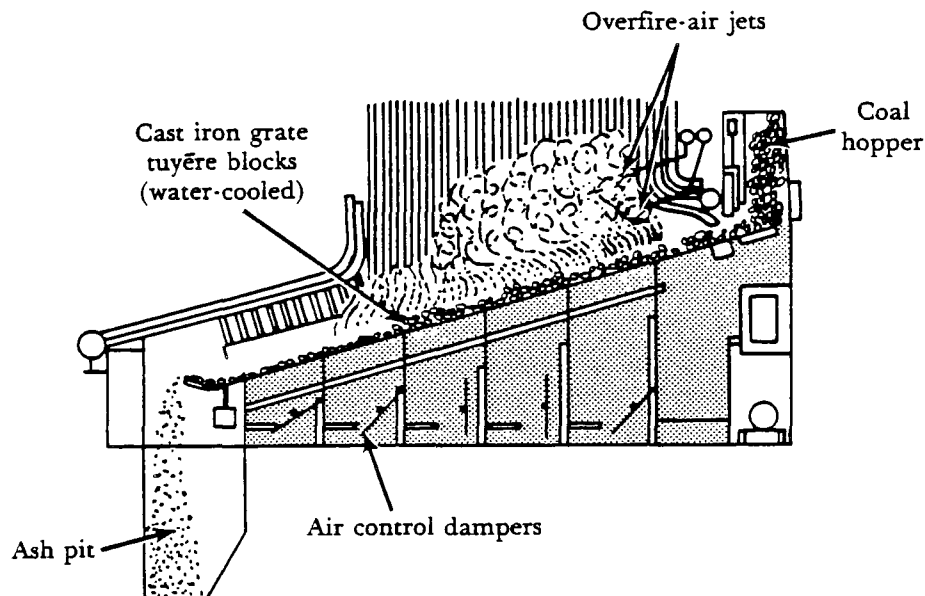


Figure 3-6. Vibrating-grate stoker.

These three stokers are used to burn different coals. Chain-grate stokers are used for noncaking high-volatile, high-ash coals. Traveling-grate stokers are used for lignite, and small-sized pieces of anthracite coal and coke breeze. Vibrating-grate stokers are used for medium- and high-volatile bituminous coals, low-volatile bituminous and subbituminous coals, and lignite at reduced burning rates. Overfeed stokers are not as suitable for burning high-coking coals than are underfeed stokers.

Spreader Stokers

In a spreader stoker, coal is spread over a grate by mechanical feeders located in the front of the furnace. Fine particles of coal and volatile gases burn while suspended above the grate. The remainder of the coal fed into the furnace falls onto the grate forming a thin bed of burning fuel. A forced-draft fan blows air through openings in the grate. Some of this air is used to burn the thin bed of coal on the grate, the remainder passes up through the furnace to burn the fine particles of coal in suspension and the volatile gases. Overfire-air jets on the front wall of the furnace supply additional air for suspension burning and produce turbulence. Many spreader stokers use overfire-air jets on the front and back walls of the furnace to help provide turbulence for mixing volatile gases, to prevent the flames from scorching the furnace walls and to keep them out of the coal-feeder throat.

A number of different mechanical feeders are used on spreader stokers. Most of the feeders use adjustable rotor speeds, a feed plate, and a deflector to distribute the

coal evenly on the grate. Coal is fed from hoppers on the front wall of the furnace to a revolving motor with protruding blades. By varying the speed of the rotor and the place for coal to fall on the rotor blades, the operator can distribute the coal to various locations in the furnace. One mechanical feeder for a spreader stoker is shown in Figure 3-7.

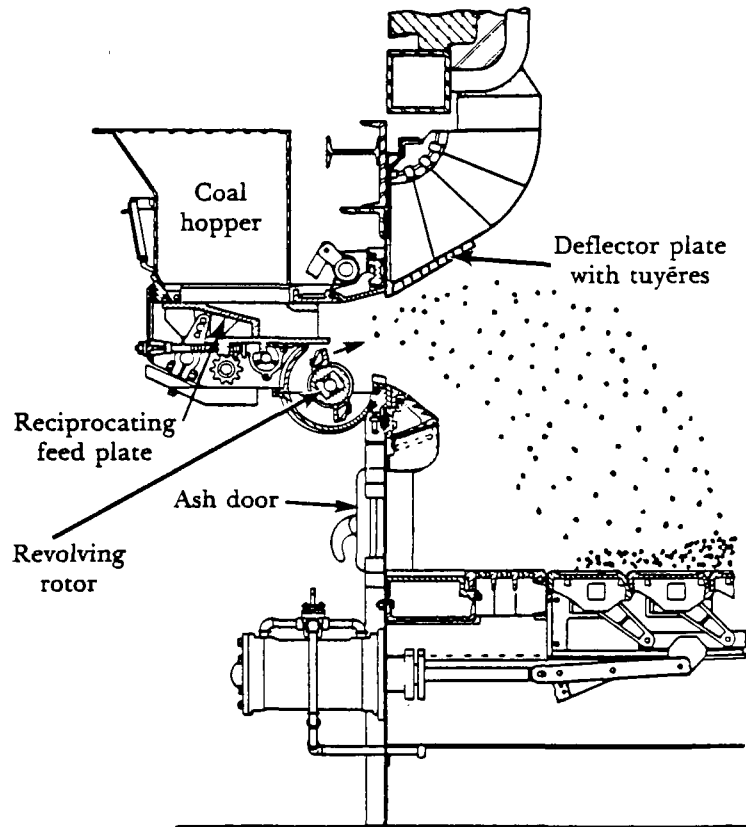


Figure 3-7. Mechanical feeder on a spreader stoker.

Spreader stokers use a wide variety of grates and ash removal methods. Simple units use stationary grates similar to those used in hand-fired boilers. These units use at least two feeders that deposit coal onto the grate. When the ash deposits fill a grate, its feeder taken out of service, the fuel bed burns down, and the ash is raked through the furnace door.

Dumping grates can also be used to remove ash from the grate. One feeder is taken out of service, the flow of air through the grate is stopped, and the ash is dumped into ash pits located below the furnace (Figure 3-8). The dumping grates can be operated by hand or by steam- and air-powered cylinders. During the dumping cycle, the coal feed to other furnace sections is increased to prevent a drop in steam pressure in the boiler. Dumping grates have been used on spreader stokers that can produce 15,000 to 75,000 pounds of steam per hour.

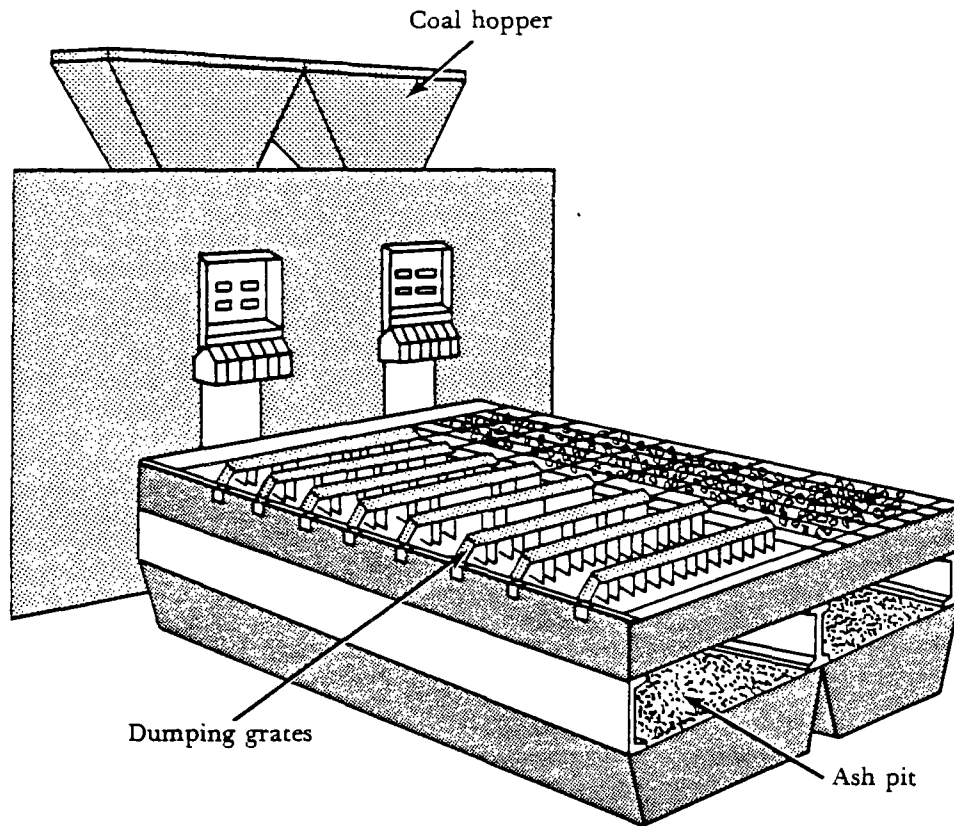


Figure 3-8. Spreader stoker with a dumping grate.

Large spreader stokers use a continuous ash removal system. Vibrating grates have been used, but the most popular are traveling grates. These operate similarly to those used in overfeed stokers. A traveling grate ash removal system used on a spreader stoker is shown in Figure 3-9. Coal is thrown onto the grate, and is burned while the grate slowly moves through the furnace. The ash is dumped into an ash pit located below the grate. Most traveling grates dump ash into ash pits located in the front wall beneath the stoker. However, some have been designed to use ash pits located in the furnace rear. Spreader stokers can produce as high as 400,000 pounds of steam per hour.

In many spreader stokers, collected fly ash, cinders, and bottom ash are reinjected into the furnace. Because a portion of the coal is burned in suspension, some of it is carried out of the furnace as cinders by the flue gas before it is completely burned. Cinders are collected in hoppers located beneath the convection section of the boiler. Fly ash is usually collected in cyclones or electrostatic precipitators. Some unburned carbon is also deposited in the ash pit. These collected cinders, fly ash, and bottom ash are occasionally reinjected into the furnace through openings in the rear wall improving stoker efficiency by as much as 3 to 5%. However, maintenance increases because reinjection piping may become plugged and dust collectors, ducting, and fans may be subject to abrasion.

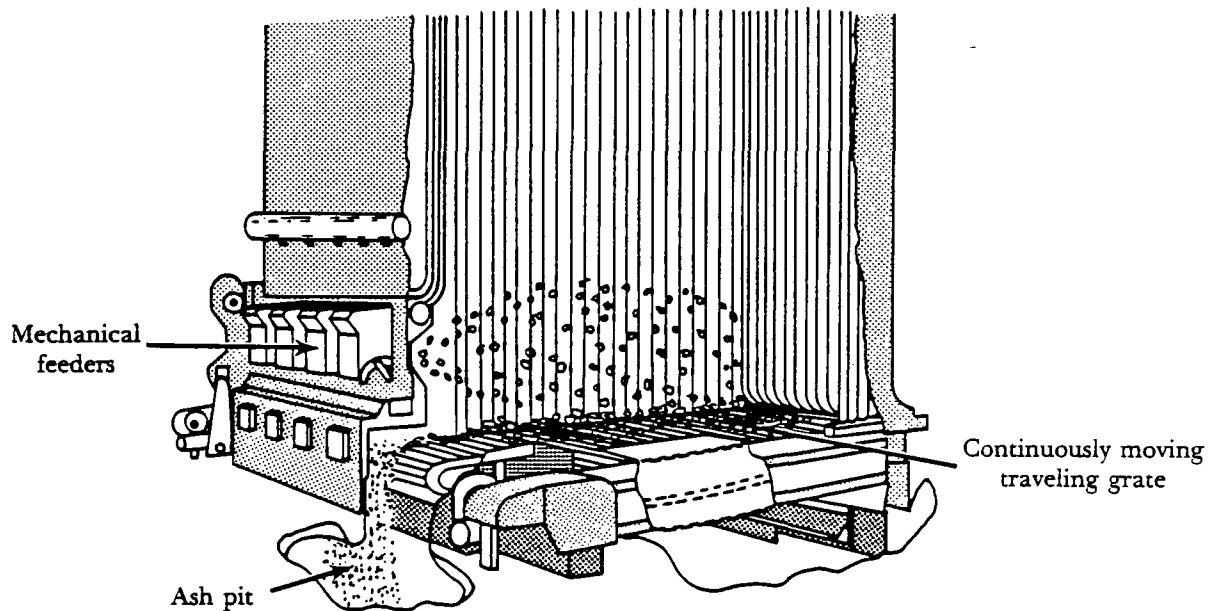


Figure 3-9. Spreader stoker with a traveling grate.

In the spreader stoker, the fuel bed is thin and a portion of the coal burns in suspension. As a result, the spreader stoker can respond rapidly to changes in steam demand. It will burn a variety of coals ranging from lignite to semianthracite. Coals that tend to form clinkers on the grate can be burned because of the spreading action in the furnace. The spreader stoker can also burn municipal solid waste, bark, bagasse, woodchips, sawdust, and coffee grounds.

Pulverized-Fired

Some large industrial boilers and most electric utility boilers use pulverized-coal (PC) firing. Pulverizing the coal creates a large surface area to be exposed to oxygen, thus accelerating combustion. Each boiler uses one or more pulverizing units where coal is pulverized into a powder before it passes to the burners in the furnace. Coal is fed to the pulverizers to meet the steam demand to the boiler. Warm air from the air preheater dries the coal in the pulverizer. This preheated air also carries the pulverized coal from the pulverizers to the burners. Combustion occurs as the fuel and primary air leave the burner tip. Secondary combustion air passes through openings in the burner, where it mixes with coal and primary air to create the necessary turbulence to burn the coal in suspension.

Pulverizers

Three types of pulverizers are used—contact mills, ball mills, and impact mills. Each of these is designed to pulverize bituminous coal so that approximately 65 to 70% will pass through a 200-mesh sieve and 99% will pass through a 40-mesh sieve.

A contact mill contains stationary and power-driven grinding elements. Coal passes between the elements where a rolling action pulverizes it into fine powder.

The grinding elements can be balls rolling in rings, or races; or they can be rings that move around stationary rollers. Figure 3-10 shows a contact mill using a ball and race arrangement. The balls are located between the two grinding elements, or races—an upper race that is stationary and a lower race that is power driven. Coal is fed through a hopper into the contact mill. The coal is pulverized between the balls and the lower race. This pulverized coal is blown up into a rotary classifier where oversized pieces are sent back to the balls and races and are repulverized. The fines are blown to the burners. A forced-draft fan supplies hot air to dry the coal, and to move it through the mill to the burners. The mill is therefore slightly pressurized and if the casing leaks, pulverized coal may be blown into the room where the mill is located.

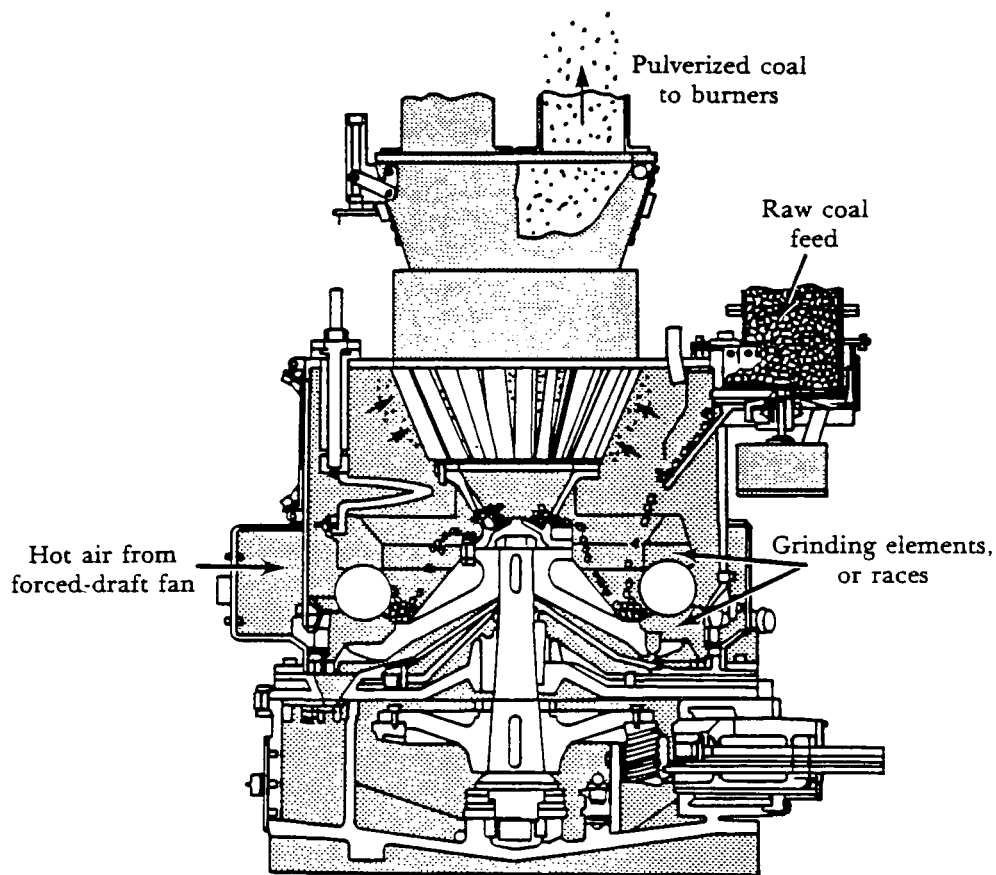


Figure 3-10. Contact mill using balls and races used to pulverize coal.

The contact mill shown in Figure 3-11 uses rollers and a ring as grinding elements. The ring is power driven and revolves around two or three stationary rollers, or tires. The rollers rotate as the ring revolves and the coal is ground between the two surfaces. The ground coal is carried by primary air through a classifier where oversized pieces are separated and reground. Pulverized fines are sent to the burners.

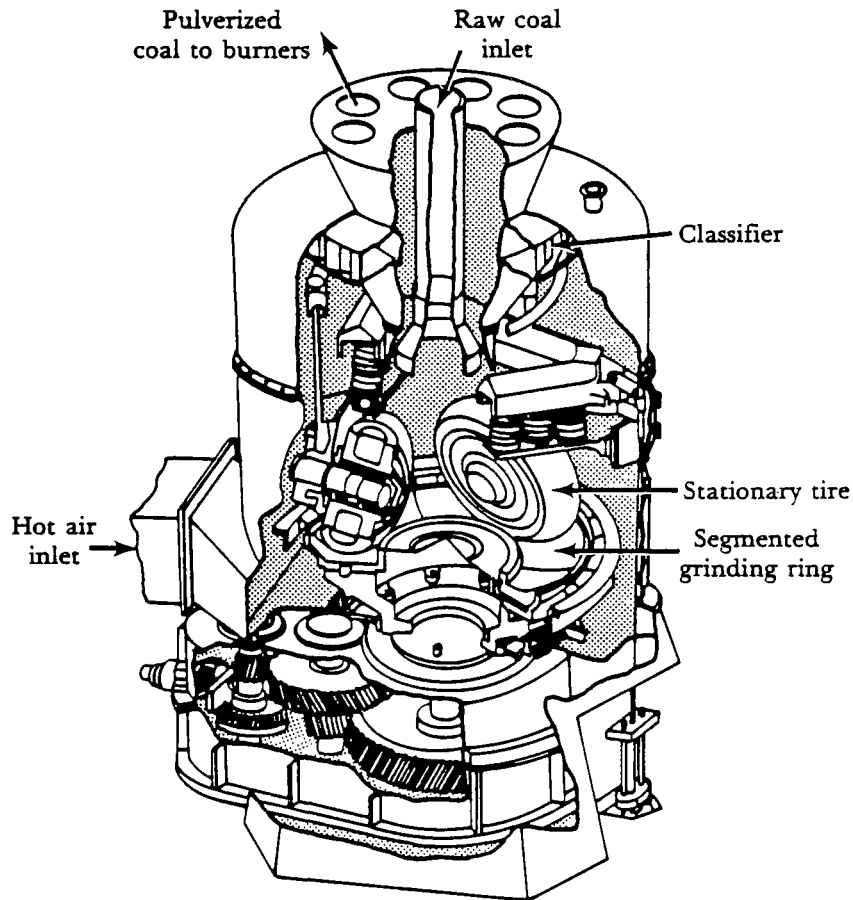


Figure 3-11. Contact mill using a revolving ring and roller (stationary tires) used to pulverize coal.

A typical ball mill, shown in Figure 3-12, consists of a drum partly filled with steel balls of varying sizes. The drum slowly rotates as coal is fed into it. Coal is crushed as the balls rub against each other. Hot air is blown into the drum to dry the coal during the pulverizing step. Pulverized coal passes through classifiers, then to the burners. Oversized pieces from the classifier are returned to the drum for additional grinding.

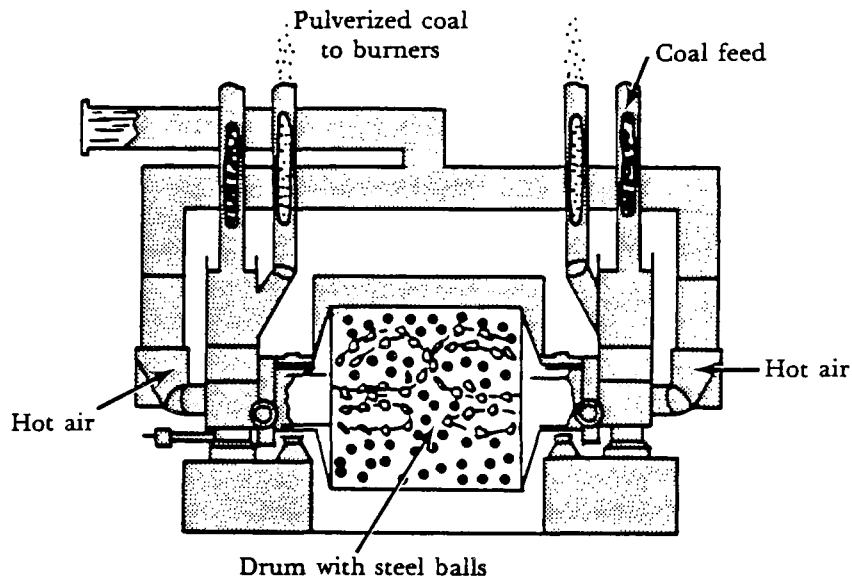


Figure 3-12. Ball mill used to pulverize coal.

In an impact mill, shown in Figure 3-13, the coal remains in suspension during the entire pulverizing process. The grinding elements and the primary air fan are connected to the same shaft. An induced-draft fan pulls heated air and coal (in suspension) through the mill. Coal is ground to a granular state by hammers in the primary grinding stages. In the final grinding stages, rotating disks move between stationary pegs. The coal moves toward the center of the pulverizer where rotating scoop-shaped rejector arms throw large coal particles back into the grinding sections. The fines are passed through the fan and discharged into the burners. These mills can adjust very rapidly to changes in steam demand. Impact pulverizers are also called Atrita pulverizers.

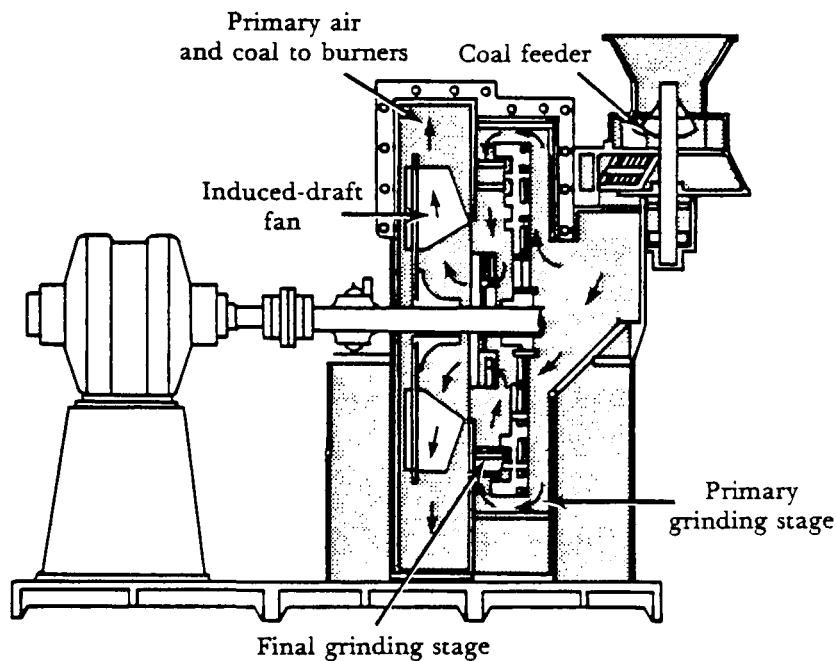


Figure 3-13. Impact mill used to pulverize coal.

Burners

Burners are designed to efficiently mix air with fuel to promote complete combustion. Coal and heated primary air usually move through the center part of the burner. Secondary combustion air is supplied from the windbox to the burner by a forced-draft fan. The amount of secondary air coming in through the burner is controlled by dampers. Occasionally, tertiary air will be brought into the furnace through openings, or ports, on the furnace wall or through openings around the outside wall of the burner. Coal is ignited by inserting a burning gas, oil, or kerosene torch into the burner.

Many different burner designs are used in pulverized coal-fired boilers. Figure 3-14 shows a typical wall-mounted burner. In this burner, fuel and air are mixed by impellar vanes. The boiler is usually equipped with a number of these burners mounted on the walls of the furnace.

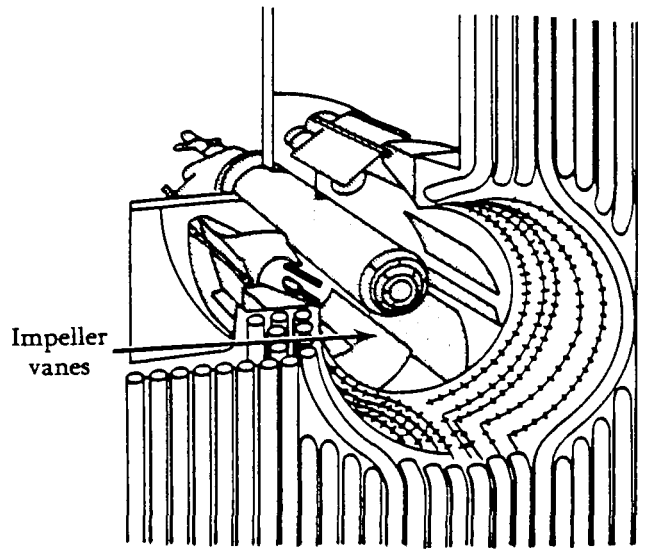


Figure 3-14. Typical burner used for pulverized coal firing—circular register burner.

The intervane burner, shown in Figure 3-15, imparts a rotary motion to the coal and primary air mixture in a central nozzle. This rotary motion provides good air and fuel mixing (turbulence). Secondary air flows into the furnace from a register that surrounds the nozzle. Coal is ignited by using an oil igniter.

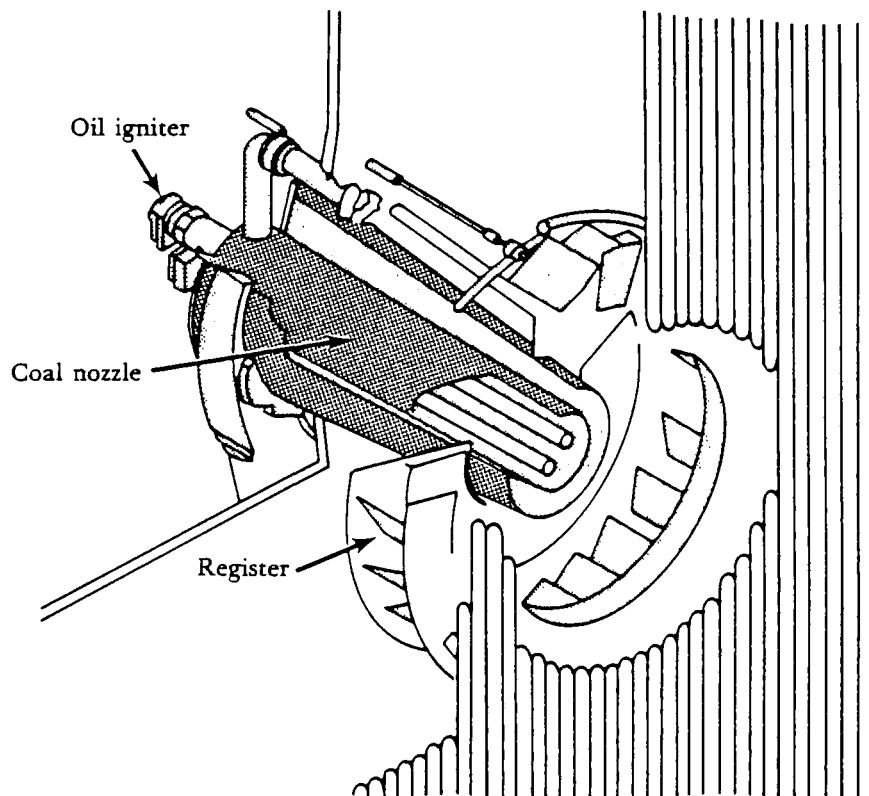


Figure 3-15. Intervane burner used for pulverized coal firing.

In the horizontal burner, shown in Figure 3-16, coal is fed through a central nozzle with internal ribs. The nozzle is surrounded by a housing containing adjustable vanes to control air turbulence and flame shape. Coal is ignited by inserting an ignition torch through the central tube.

The shape of the flame in the furnace depends on the type of burner used and location or firing pattern shown in Figure 3-17. In vertical firing, burners placed at the top of the furnace produce a long U-shaped flame. In horizontal firing, burners extend through the furnace wall producing a turbulent cone-shaped flame. Burners can be mounted on one side or on opposite sides of the furnace. In tangential firing, the furnace has one or more burners in each corner. The flames move toward the furnace center forming a large swirling ball of flames.

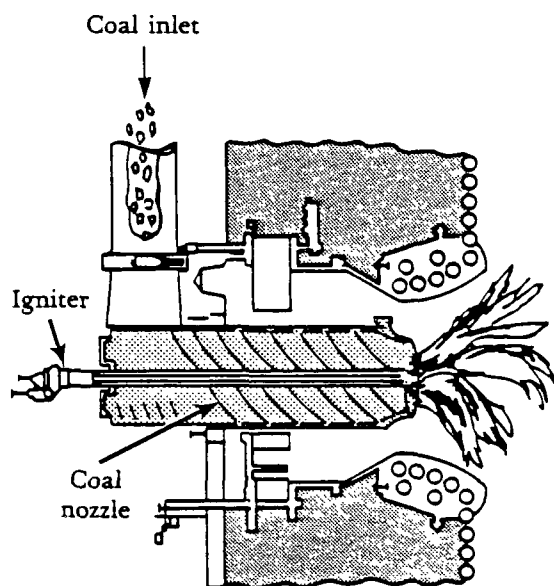


Figure 3-16. Horizontal burner used for pulverized coal firing.

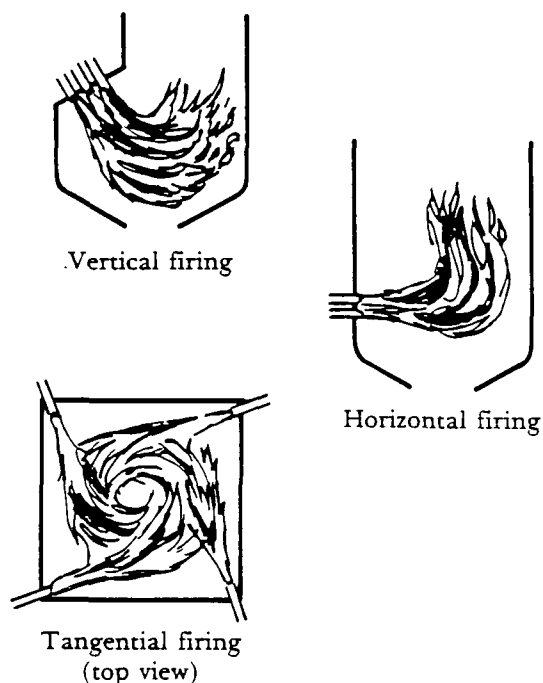


Figure 3-17. Various firing patterns of pulverized coal-fired boilers.

Advantages and Disadvantages

The ash in the coal can present operating and maintenance problems that must be considered when designing the furnace. Small- and medium-sized furnaces have ash removed in the dry state, and are called *dry bottom* units. The temperature of the furnace must be maintained below the ash-fusion temperature of the coal being burned. If this precaution is not taken, large quantities of slag can form, fouling the boiler surfaces. In some larger furnaces, the furnace temperature is maintained above the ash-fusion temperature of the coal. In this case the bottom ash is in the molten state, called slag. The slag is tapped from the furnace and then chilled by water. The rapid change in temperature causes the molten slag to shatter into small pieces of ash. These pulverized units are referred to as *wet bottom*.

Pulverized coal-fired boilers have the following advantages and disadvantages (Woodruff and Lammers, 1977):

Advantages

- Can adjust very quickly to varying steam demands.
- Requires low amount of excess air.
- Reduces or eliminates heat losses due to furnace banking.*
- Can be repaired without cooling down the furnace because most of the equipment is located outside the furnace.
- Can burn a variety of coals.
- Can use high-temperature preheated air successfully—thus increasing furnace efficiency.
- Easily adapted to automatic combustion control.

Disadvantages

- Costly to install.
- Requires skilled personnel to operate because of explosion possibilities.
- Has high fly ash carryover—requiring the use of electrostatic precipitators or baghouses to meet emission regulations.
- Requires multiple mills and burners to obtain satisfactory operating ranges.
- Slag deposits may form on lower boiler tubes.
- Requires extra power to pulverize coal.

Fluidized-Bed

Fluidized-bed boilers have recently been used in some industrial and electric utility steam generators. These boilers are frequently referred to as atmospheric fluidized-bed (AFB) combustion units. The technology of fluidized-bed boilers evolved in oil refineries and chemical plants where they were used in many processes and also to destroy gaseous, liquid, and solid wastes.

In a fluidized-bed boiler, coal and an inert material such as sand, alumina, ash (from the fuel), or limestone, are suspended in a combustion chamber by air blowing up through the bed. Fluidizing the fuel bed provides turbulent mixing required

*The furnaces of stoker-fired boilers are banked with coal that is burned very slowly during periods when there is a low demand for steam. A banked furnace can quickly be returned to full service by adding more coal and combustion air.

for good combustion. The amount of fluidization that occurs depends on the size of coal and inert material and the velocity of the air moving through the bed. The fluidized-fuel bed essentially behaves as a liquid. The resulting improvement in fuel mixing allows the fuel to burn at lower temperatures, approximately 1500 to 1600°F, compared to other coal-fired boilers. Thus, the combustion chamber of a fluidized-bed releases heat at an equivalent level to that of a conventional boiler, but at lower temperatures without any theoretical loss in efficiency.

Fluidized-bed boilers offer some advantages over conventional designs in terms of reducing air pollutants. Because the operating temperatures are relatively lower, nitrogen oxide emissions will be lower. In fluidized-beds using limestone in the fuel bed, sulfur oxides, formed as the sulfur in the coal oxidizes, combine with the limestone to form calcium sulfate and sulfite particles that can be collected in an electrostatic precipitator or a baghouse.

Figure 3-18 shows a typical fluidized-bed boiler. Some fluidized-bed boilers use underbed feed systems, where coal is fed underneath the fluidized-bed. Others use overbed feed systems, and/or a combination of underbed and overbed feed systems. Overbed feed systems consisting of gravity-feed pipes or conventional spreader-stoker mechanisms have been successfully used. Many systems use perforated plates with equally-spaced holes that distribute air evenly through the fuel bed providing uniform fluidization. Some systems use steam tubes placed directly in the fluidized bed, while others use separate combustion chambers followed by convection sections, superheaters, and economizers.

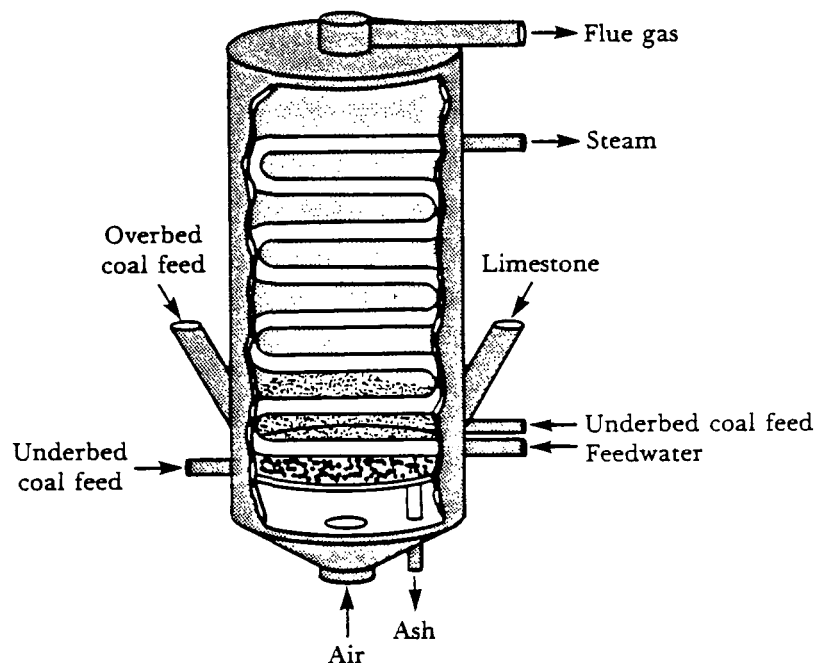


Figure 3-18. Schematic of a fluidized-bed boiler.

Fluidized-bed boilers can be designed to burn many different grades of coal, wood chips, solid wastes, and shredded tires. Fluidized-bed boilers are capable of producing 10,000 to 600,000 pounds of steam per hour.

Summary

Boiler designs affect the application of air pollution control and the response time to generate steam. Underfeed and overfeed stokers usually have lower fly ash carryover than do spreader stokers or pulverized-coal-fired boilers. Fine powdery fly ash is more readily carried with the flue gas. Data available on the fluidized-bed indicate that the fly ash carryover from these units are less than from pulverized-coal boilers. In terms of response time, in other words, the unit's ability to start up and change for various steam demands, pulverized-fired boilers are the quickest. These units are followed in order by fluidized beds, spreader stokers, overfeed stokers, and underfeed stokers.

Oil-Fired Boilers

Oil is used as fuel in many commercial and industrial boilers and in some utility boilers. The design of the combustion system depends on the grade of fuel oil burned and on the size of the boiler. As stated in Lesson 2, fuel oils are graded according to gravity and viscosity, the lightest being No. 1 and the heaviest being No. 6. Light distillate oils, such as No. 1 (kerosene), will readily vaporize in simple burners. Heavy fuel oils such as No. 6 must be heated to be adequately pumped to and burned in the burners.

Boiler Sizes

Boilers generate steam or heat for many commercial establishments. Commercial-sized boilers typically burn Nos. 4, 5, and 6 fuel oil at a rate of 3 to 100 gallons per hour (gph) (EPA, 1980). Electric heat is often used to decrease the viscosity of heavier fuel oils so that they will vaporize at the burner tip. Steam can also be used to heat heavy fuel oils. If distillate oils, Nos. 1 and 2, are burned, they do not need to be heated. Commercial-sized units are designed to use approximately 20 to 30% excess air. Fire-tube and water-tube (packaged) boilers are used for commercial establishments.

Industrial-sized boilers usually burn Nos. 4, 5, and 6 fuel oil at a rate of 70 to 3500 gph (EPA, 1980). Steam heaters are often used to heat these heavy fuel oils. Industrial boilers are shipped as packaged units or fabricated at the plant site. These boilers are designed to operate with approximately 10 to 15% excess air.

Utility boilers firing fuel oil burn No. 6, Bunker C, at rates of 3500 to 60,000 gph (EPA, 1980). These boiler systems usually include steam or electric heaters, insulated and/or heat traced piping, suction strainers for removing sludge, meters, and regulating and safety valves. Utility boilers are usually erected in the field and are designed to operate with approximately 2 to 4% excess air.

Burners

Steam-, air-, or pressure-atomizing burners are most frequently used for firing oil. Oil is atomized into very fine particles by the burner before it is burned. A steam-atomizing burner (internal mix) is shown in Figure 3-19. The oil is atomized as the

steam contacts it, before reaching the burner tip, forming a short, bushy flame. These burners are used on commercial, industrial, and utility boilers at firing rates up to 1100 gph. An air-atomizing burner is shown in Figure 3-20. This burner uses low-pressure air to atomize the oil. Oil enters the rear of the burner and flows through a central tube. Oil combines with primary and secondary air at the end of the tube. Primary air moves through tangential vanes causing air to swirl as it passes around the stream of oil. This mixture combines with secondary air at the burner tip. These burners can burn No. 2 fuel oil or Nos. 4 and 5 fuel oil when used on commercial-sized boilers. A mechanical pressure-atomizing burner is shown in Figure 3-21. Oil flows at high pressure through a center tube and is discharged through tangential slots in a swirling chamber. The swirling oil passes through a sprayer-plate into an orifice where some of the oil moves through an orifice plate while a portion is returned to the suction pump. The amount of oil returned is determined by the position of the return-line control valve. Oil leaving the burner tip forms a conical spray.

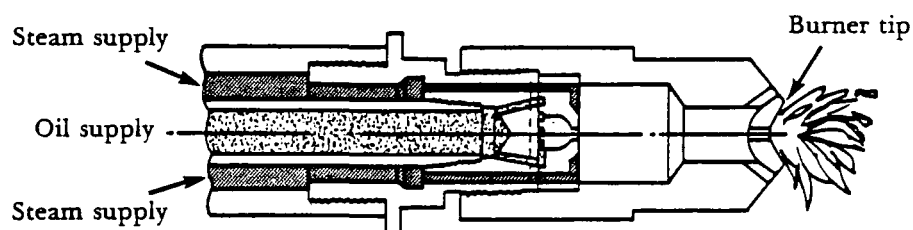


Figure 3-19. Internal mix steam atomizing burner used for oil firing.

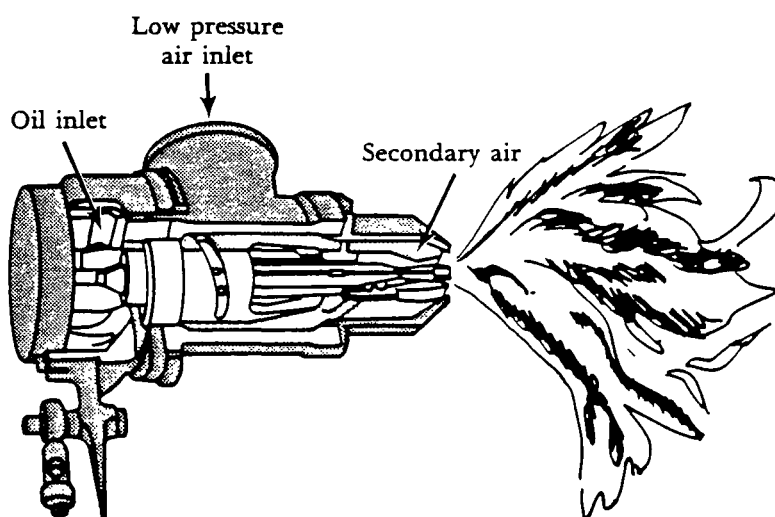


Figure 3-20. Air atomizing burner used for oil firing.

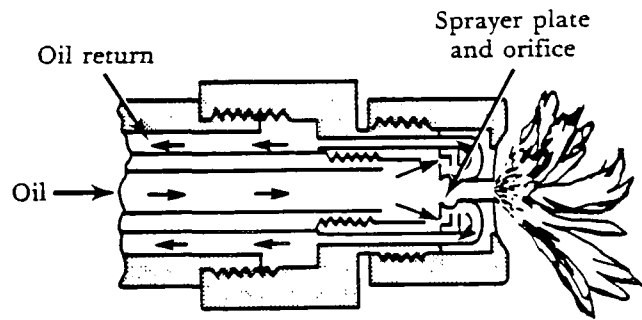


Figure 3-21. Mechanical pressure-atomizing burner used for oil firing.

Summary

Fuel oil burned in boilers to generate steam has the following advantages over coal (Woodruff and Lammers, 1977):

- Oil can be stored without deteriorating or combusting spontaneously.
- Plants can be operated with less labor than coal-burning steam plants, because of ease in operating oil transporting and burning equipment and because less ash is produced when oil is burned.
- Combustion processes can be automatically controlled.
- Initial plant costs are less than for coal-burning plants because coal- and ash-handling equipment are not necessary.
- Plants are easier to keep clean.
- Plants produce lower amounts of air pollutants than coal-burning plants. (However, the amount of SO₂ and NO_x emissions can still be significant).

Gas-Fired Boilers

Gaseous fuels burned in boilers are natural gas, by-product coke oven gas, blast furnace gas, refinery gas, and manufactured gas. Natural gas is readily available because of the vast network of gas pipelines. Other gases are used in the plants where they are produced or in neighboring plants. Natural gas is burned in smaller boilers, usually for residential or commercial establishments. Gas is occasionally used as a back-up fuel for industrial and utility boilers. It is also used for igniting pulverized coal-fired boilers.

Burners

Gas burners vary in the way they mix air and fuel. A simple premix burner is shown in Figure 3-22. Gas and primary air are mixed upstream of the burner tip. Secondary air is brought in at the burner tip. These burners are used on small residential- and commercial-sized boilers. Industries that have a large supply of blast-furnace or coke-oven gas readily available occasionally use them in boilers to produce steam or electricity.

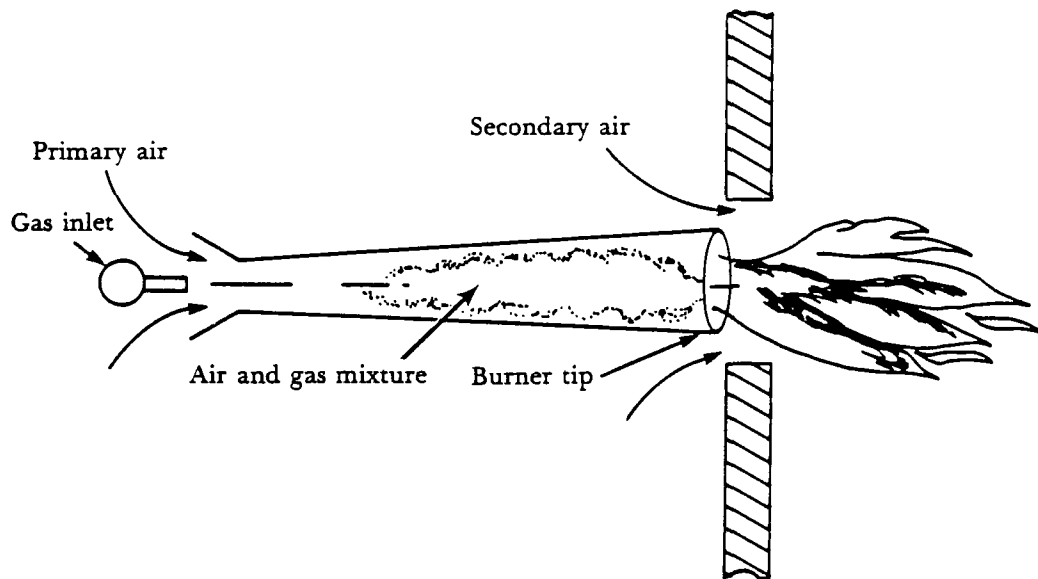


Figure 3-22. Premix burner used for gas firing.

A burner that can be used to fire gas and/or oil is shown in Figure 3-23. Gas enters through a large circular ring at the burner throat. Air from a windbox enters at the back end of the burner tube. Curved vanes impart a whirling motion to the air. Air mixes with the gas in the burner tube. The oil tube runs through the center of the burner. The oil tube runs through the center of the burner.

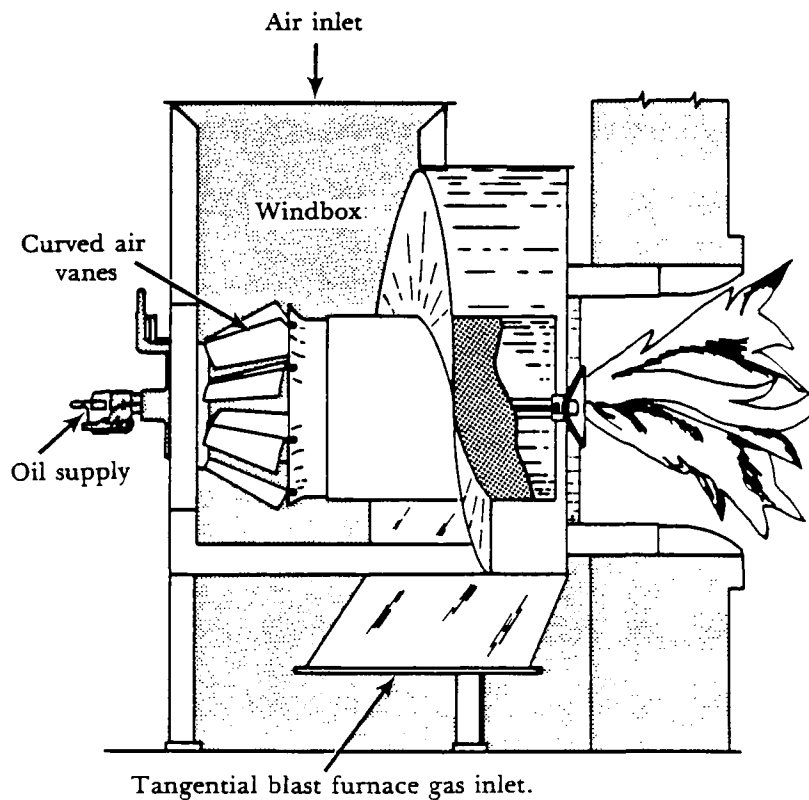


Figure 3-23. Combined blast furnace gas and oil burner.

Summary

The maintenance of gas-fired boilers is usually less than either oil-fired or coal-fired boilers. However, gas burners must be maintained because burners can become clogged. Air register mechanisms must be in good operating conditions and the boiler settings must be frequently checked to reduce air inleakage. Burning gas produces less air pollutants than do either oil or coal, because gas contains very little sulfur and virtually no ash.

Review Exercise	
1. In a _____ system, a fan located after the boiler pulls air through the boiler and out the stack. a. natural-draft b. forced-draft c. induced-draft	
2. _____ fans are frequently used for induced-draft systems, especially if the flue gas contains a high concentration of dust. a. Radial b. Backward-curved c. Forward-curved	1. c. induced-draft
3. In a(an) _____, coal is fed into the furnace through long troughs called retorts. a. overfeed stoker b. underfeed stoker c. traveling-grate stoker d. spreader stoker	2. a. Radial
4. In an underfeed stoker, a _____ forces coal through the length of the retort and upward. a. mechanical spreader b. chain grate c. screw feeder d. mechanical ram or screw feeder	3. b. underfeed stoker
5. True or False? Multiple retort underfeed stokers are inclined slightly to aid in moving the coal and ash through the retorts.	4. d. mechanical ram or screw feeder
	5. True

6. In underfeed stokers, combustion air comes through openings in the grate called a. tuyères. b. windboxes. c. over-fire air jets.	
7. Chain-grate and traveling-grate stokers are a. underfeed stokers. b. overfeed stokers. c. spreader stokers.	6. a. tuyères.
8. _____ stokers use grates constructed of closely fitted links of steel and cast iron while _____ stokers use grates made of steel bars attached to a separate chain. a. Spreader, chain-grate b. Chain-grate, traveling-grate c. Traveling-grate, chain-grate d. Chain-grate, vibrating-grate	7. b. overfeed stokers.
9. In both traveling-grate and chain-grate stokers, combustion air enters the furnace through openings in the _____, and through _____ located on the front wall. a. tuyères, grates b. grates, tuyères c. grates, overfire-air jets	8. b. Chain-grate, traveling-grate
10. In vibrating-grate stokers, the grate is made of a. cast-iron blocks attached to water-cooled tubes. b. closely fitted bars attached to a separate chain. c. steel bars that continuously move from the front to the back of the furnace.	9. c. grates, overfire-air jets
11. In a _____, fine particles of coal and volatile gases burn while suspended above the grate. a. single-retort underfeed stoker b. spreader stoker c. overfeed stoker d. vibrating-grate stoker	10. a. cast-iron blocks attached to water-cooled tubes.
12. Spreader stokers use _____ to feed coal into the furnace. a. shovels b. traveling grates c. pulverizers d. mechanical feeders	11. b. spreader stoker
	12. d. mechanical feeders

13. In most spreader stokers, ash is removed from grates by _____ or _____. a. traveling grates, dumping grates b. vibrating grates, mechanical rams c. screw conveyors, tuyères	
14. True or False? In pulverized-coal firing, coal is heated by hot air from the air preheater.	13. a. traveling grates, dumping grates
15. Coal can be pulverized into a very fine powder by using a. ball mills. b. contact mills. c. impact mills. d. all of the above	14. True.
16. In a contact mill, coal is crushed as it moves between grinding elements. These elements are a. balls rolling in rings, or races. b. rings that move around stationary rollers. c. a drum filled with steel balls. d. a. and b. above e. all of the above	15. d. all of the above
17. True or False? In burners used for pulverized-coal firing, coal is ignited by inserting a burning-gas, oil, or kerosene torch.	16. a. and b. above
18. In most burners used for pulverized-coal firing, _____ move(s) through the center part of the burner. a. secondary air b. primary air c. coal and primary air d. none of the above	17. True.
19. A pulverized-coal-fired boiler using a tangential-firing pattern has a. six burners mounted on the front and back walls of the furnace. b. one or more burners in each corner of the furnace. c. two rows of burners in both the top and bottom of the furnace.	18. c. coal and primary air
	19. b. one or more burners in each corner of the furnace.

20. In pulverized-coal boilers, if the bottom ash is removed from the furnace while it is in a molten state, these units are referred to as a. dry bottom. b. slag spreaders. c. wet bottom. d. none of the above	
21. In fluidized-bed boilers, coal and inert materials are suspended in the combustion chamber by a. a chain grate. b. mechanical rams and screw feeders. c. electrical fluidizers and bar grates. d. air blowing down through the bed. e. air blowing up through the bed.	20. c. wet bottom.
22. True or False? Fluidized-bed boilers are capable of reducing both SO ₂ and NO _x emissions. This is because limestone in the fuel bed combines with NO _x to form calcium nitrate. Because the furnace temperature is relatively low, SO ₂ formation is also reduced.	21. e. air blowing up through the bed.
23. Which of the following has the highest fly ash carryover from a boiler furnace. a. underfeed stoker b. traveling-grate stoker c. spreader-stoker d. pulverized-coal-fired boiler e. fluidized-bed boiler	22. False. SO ₂ combines with limestone to form calcium sulfate and NO _x emissions are reduced because of the low furnace temperatures.
24. Which of the following fuel oils is(are) usually heated before being pumped to and burned in burners? a. No. 1 and No. 2 b. kerosene c. No. 5 and No. 6	23. d. pulverized-coal-fired boiler
25. True or False? Fuel oils are atomized in the burner by using steam, air, or mechanical pressure.	24. c. No. 5 and No. 6
	25. True.

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Lesson 4

Operation and Maintenance

Lesson Goal and Objectives

Goal

To familiarize you with normal boiler operation and maintenance, including system controls and safety practices.

Objectives

Upon completing this lesson, you should be able to—

1. recognize the use of water columns, fusible plugs, and steam gauges in a boiler,
2. briefly describe the operation of a boiler feedwater regulator,
3. recognize soot blowers and describe their operation,
4. recognize two safety devices used to control the flow of water and steam in a boiler and to detect the presence of flames in burners, and
5. briefly describe the reason for and use of blowdown in a boiler.

Introduction

The automatic controls used on boilers will depend on the size of the boiler, the fuel that is fired, the operating pressures, and the steam requirements from the boiler. Because the operating and maintenance procedures will be unique for each boiler, it is essential that it be operated accordingly to assure continuous, safe, and efficient operation.

Controls and Instruments

Controls used on a boiler will provide for safe and efficient operation. A number of variables are measured including steam pressure and flow, furnace pressure and draft, feedwater flow, air flow, fuel supply and feed rate, and flue gas composition (CO , O_2 , and CO_2). Many of these variables are also automatically controlled to keep the boiler operating. Most controls consist of a few basic components (TPC Training Systems, 1975):

- *primary element* that senses and responds to cycle changes, such as a drop in steam pressure or too low water level.
- *error detector* that measures and compares an output signal to a set point. This is usually considered to be the actual controller.

- *relaying element* that converts the controller's signal and transmits the signal to control points.
- *power units* that receive the control impulses and then activate a device such as a damper, or close or open a valve, or feed more fuel to the boiler.

Water Glasses and Columns

Maintaining the proper water level of a boiler protects it from overheating and allows it to be adjusted for varying changes in steam demands. Some small boilers have gauge glass, or water gauges, mounted directly on the front of the boiler shell that visually show the water level. Most boilers use water columns to indicate water level. Water columns are small vessels, or tubes, connected to the boiler drum, to which gauge glasses are attached (Figure 4-1). Water columns can be located on the boiler so that they can be easily inspected and maintained. Water columns have a blowdown valve and line. Water is drained during blowdown to remove the scale and dirt that accumulate on the viewing glass. Scale and dirt could cause the water level readings to be off.

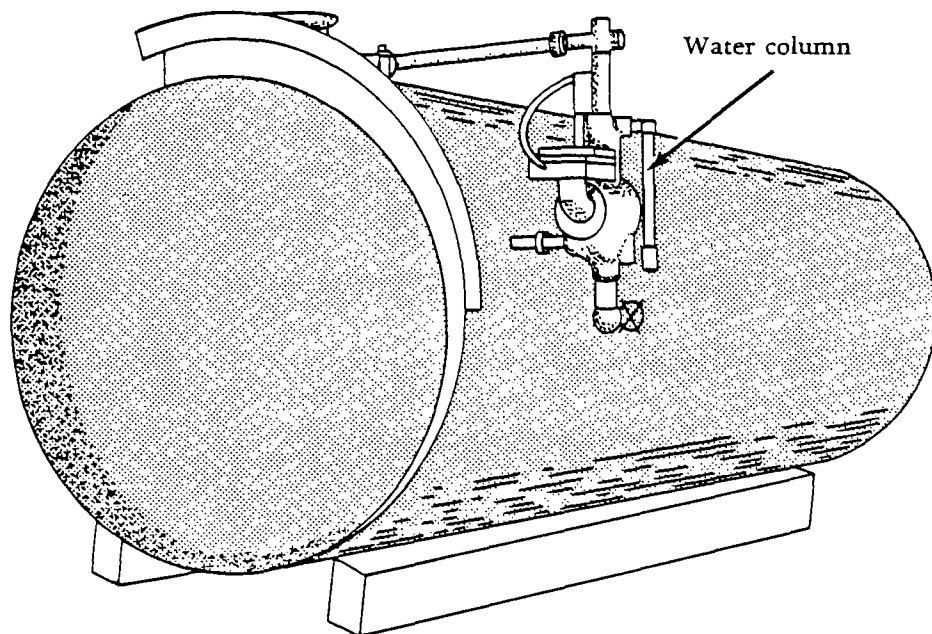


Figure 4-1. Water column on a horizontal return-tube boiler.

A simple gauge glass is suitable for boilers operating at pressures below 400 psi. It is a small glass tube fitted with valves at the top and bottom, so that steam and water flows will be shut off if the glass breaks. The gauge glass used on boilers with pressures from 400 to 2000 psi consists of flat glass strips backed with pieces of mica. The mica separate the glass from high-temperature steam and water. A bicolor glass gauge is used on boilers operating with high pressures, 1000 psi to 3000 psi. It operates on the optical principle that light beams bend differently when they pass through water or steam. The illuminated gauge contains a green glass and a red

glass sandwiched together. The green glass detects water and the red glass detects steam. The water level is where the two colors appear to meet. If water is in the glass gauge, red light will be bent out of the field of vision and green light will appear. If steam is in the glass gauge, green light will be bent out of the field of vision and red light will appear.

In a fire-tube boiler, the water level must be at least 3 inches above the top row of tubes. In a water-tube boiler, it must be adequate enough to assure that all of the tubes contain water or steam to prevent them from overheating. Overheating in both fire-tube and water-tube boilers could burst the tubes and cause a possible explosion.

Many boilers use alarms to signal when the water level is not adequate. High water alarms signal when the water level is too high and low level alarms signal when the water level is too low.

Fusible Plugs

Fusible plugs are used to sound alarms when the water level in a boiler is low. These are brass or bronze and contain a tapered hole. In an ordinary plug, the hole is filled with tin which has a melting temperature of approximately 450°F. One side of the fuse plug is exposed to hot gases, the other side to water. The water carries the heat away from the plug side exposed to the hot gases. If the water level drops below the plug, the heat will melt the tin and blow it out of the core. This causes a pressure-activated alarm to sound, warning the boiler operator that the water level is low.

Once set off, fusible plugs must be replaced. This can be done by taking the boiler out of service. However, many boilers use fusible plugs installed in a pipe connected to a valve (Figure 4-2). When the fuse blows, the valve can be shut and another fuse inserted without taking the boiler out of service. Fusible plugs should be inspected frequently to check for scale and dirt buildup on the water side and soot deposits on the fire side. These deposits will cause the plug to malfunction.

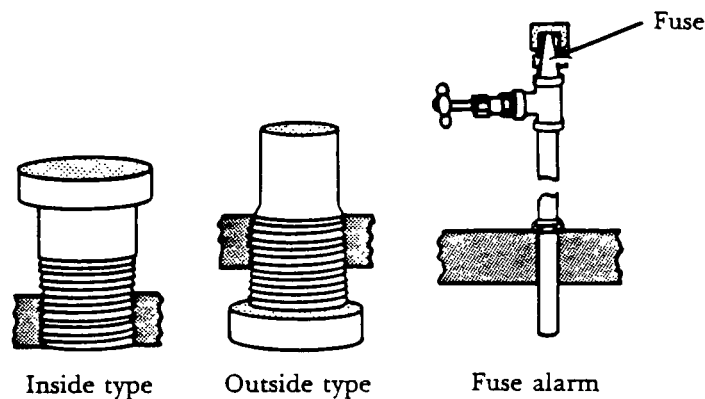


Figure 4-2. Fusible plugs and fuse alarm.

Pressure Gauges

Pressure gauges are used to measure steam and water pressure in steam drums, feed-water heaters, steam headers, and other boiler equipment. Pressure gauges are the Bourdon tube, manometer, diaphragm, and bellows.

The Bourdon tube is the most common gauge used on a boiler. It consists of a curved tube that is sealed at one end (Figure 4-3). The sealed end is connected to a pointer by linkage. The open end of the gauge is the pressure connection. As pressure increases in the tube, the tube straightens out, moving the pointer. As the pressure decreases the tube returns to the normal curved position. Bourdon pressure gauges can measure pressures of steam, air, oil, water, or other fluids. These gauges require careful handling and proper maintenance to keep them operating accurately. They should be removed from their mountings, disassembled and cleaned with a suitable solution regularly.

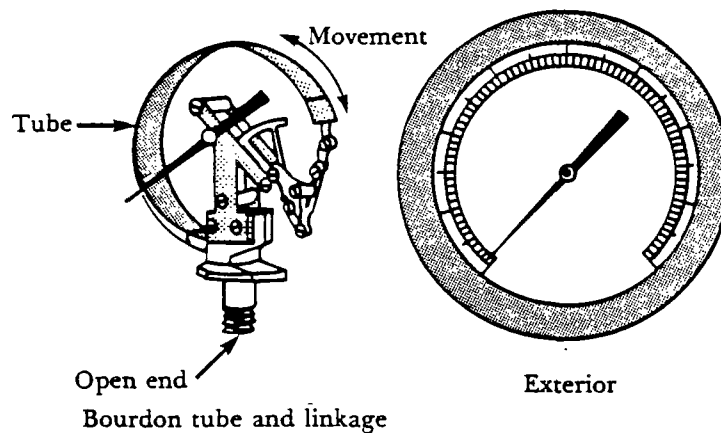


Figure 4-3. Typical Bourdon pressure gauge.

Steam gauges for a small boiler are usually mounted on top of the water column. The gauge will directly read the pressure of the boiler. In many boilers, gauges will be mounted on pipes that run from the steam drum to ground level, so that they can easily be read by the operator. At this level, the gauge reads the steam pressure plus the hydraulic head of water in the line. The true steam pressure is the value read on the gauge minus the hydraulic head. For each foot of vertical distance between the connection at the drum and the ground level, the gauge reading must be corrected by subtracting a value of 0.433 psi per foot of head. Gauges can also be mounted above the point of pressure measurement. In this case the pressure due to the hydraulic head must be added to the gauge reading.

Manometers are commonly used to measure low air pressures and pressure differences between two points. Two manometers are the single leg and U-tube. A single leg manometer is a glass tube filled with water or mercury. The top of the tube is open to the atmosphere and the pressure that is measured enters an opening in the well (Figure 4-4a). If the pressure is greater than atmospheric, the fluid in the

tube will rise. If the pressure is below atmospheric, the fluid in the tube falls. A U-tube manometer, shown in Figure 4-4b, has two legs filled with water or mercury. When both legs of the manometer are exposed to the same pressure, the manometer shows a zero reading. If there is a difference in pressure in the legs, the liquid level will rise in one leg and fall in the other. A scale beside the tube for either a single leg or a U-tube manometer indicates pressure in inches of mercury or water, depending on the type of fluid used.

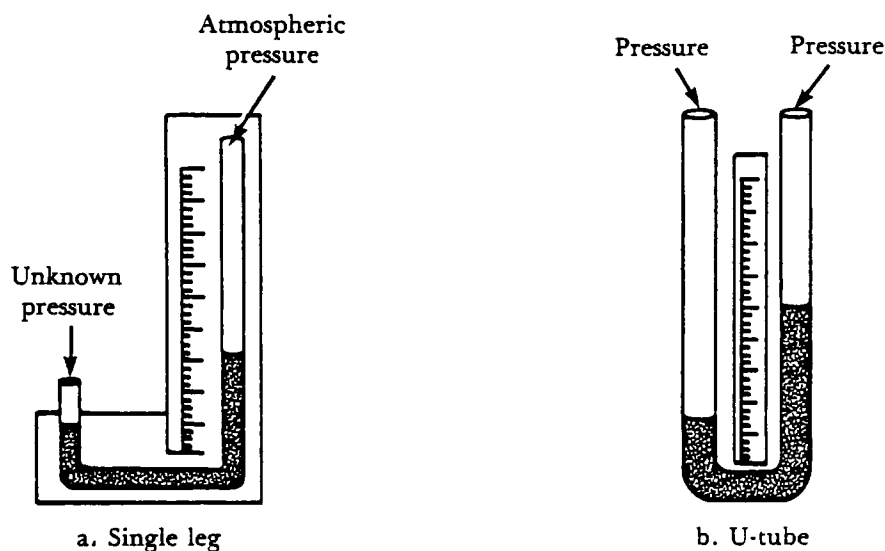


Figure 4-4. Manometers.

Manometers are useful in determining if the boiler is operating efficiently. Occasionally, tube sections become coated with heavy deposits of soot or slag that can cause a resistance to the flue gas flow. By using manometers, pressure drops across various boiler components can be detected and appropriate maintenance initiated.

Manometers must be checked regularly to ensure they are free of dirt and dust and that they have the correct amount of liquid in the tubes. All connections should be tight.

Feedwater Regulators

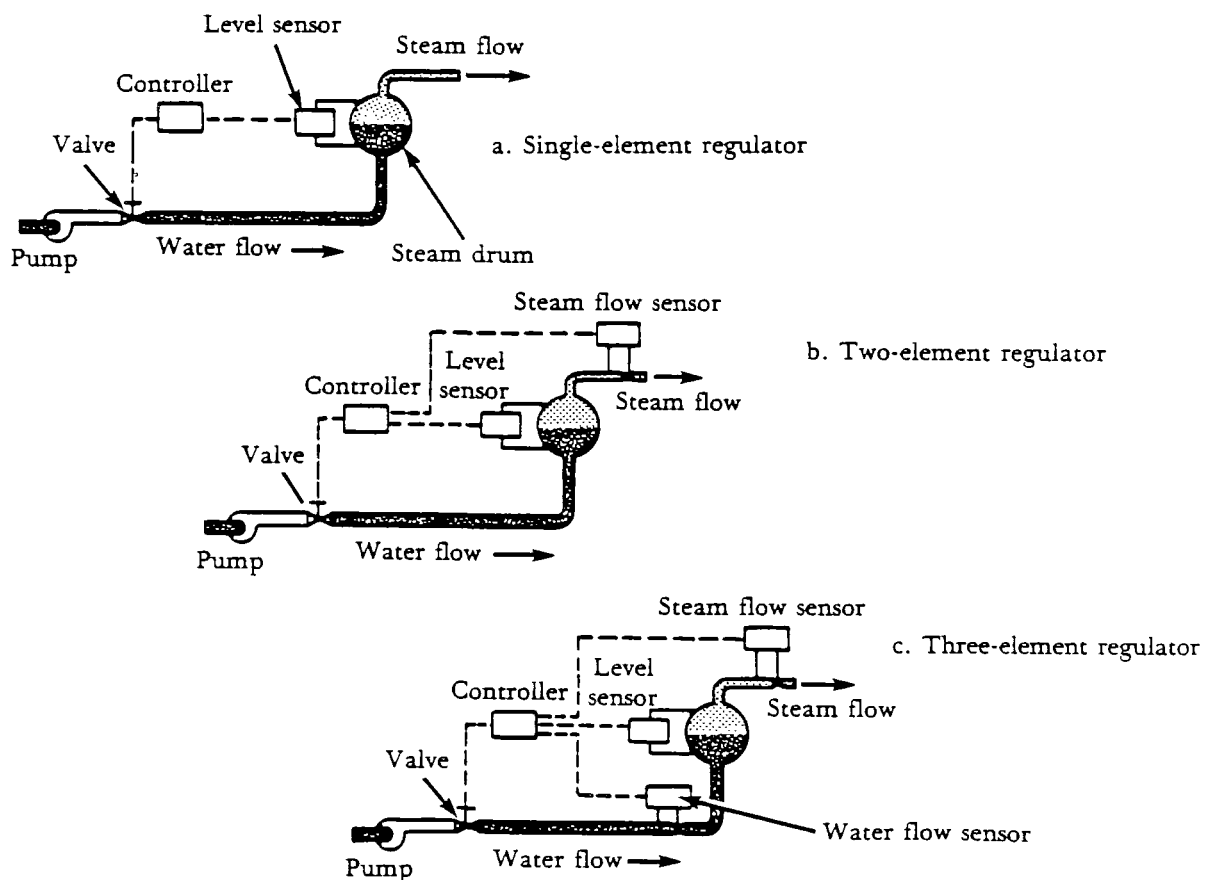
Feedwater regulators automatically control the water supply. Feedwater regulators reduce the risk of low or high water levels, increasing the safety of boiler operation. Three basic designs for feedwater regulators are the single-element, two-element, and three-element (Figure 4-5).

Small boilers, having infrequent changes in boiler load use single-element regulators (Figure 4-5a). These respond only to a change in water level. If the level of water is inadequate, the sensor sends a signal to the controller. The controller then opens or closes a valve to increase or decrease waterflow. Single-element regulators cannot compensate for water “swells” or shrinkage that occur as the firing rate in the boiler changes. When the firing rate increases, the water in the drum swells because steam bubbles form below the water surface. When the firing rate

decreases, the water volume in the drum decreases because the number of steam bubbles and their size decreases. Thus, these regulators are not used on boilers that have rapid changes in firing rates.

A two-element regulator is shown in Figure 4-5b. This regulator responds to changes in water level in the steam drum and to the steam flow from the boiler. A steam flow sensor measures the flow of steam, sending a signal to the controller as the flow of steam changes. The controller then changes the position of the feedwater valve to increase or decrease water flow to the drum. If the water level changes after the drum pressure becomes stable, the controller changes the feedwater valve to restore the proper water level. This regulator thus uses the steam flow to prevent underfeeding and overfeeding of water to the boiler drum and uses the water level sensor to finally adjust the correct water level.

A three-element regulator (Figure 4-5c) responds to changes in the water level, steam flow, and water flow. The three-element regulator maintains the correct water level in the drum by adjusting the feedwater flow to correspond to the changes of steam flow from the boiler. When the boiler load varies, the steam and water flows change immediately. Three-element regulators handle swells and shrinkage better than do two-element regulators and are used on boilers with wide and sudden load changes.



Source: TPC Training Systems.

Figure 4-5. Feedwater regulators.

Steam Headers

Steam is transported to processes or turbines through pipes or headers. Headers are cylindrical vessels from which steam is withdrawn as the demand changes. Headers are constructed to withstand internal shock and pressure because high velocity steam passes through them. Headers can also be used in superheaters and in water walls to allow steam or water to move through the boiler circulatory system.

Steam headers are insulated and provided with drains and traps to remove any water that condenses in and to prevent condensing water from entering pumps, engines, or turbines. Main steam headers are connected to branch steam lines from each boiler. This system makes it possible to use one boiler or a combination of boilers to supply steam for various industrial processes and/or turbines.

Safety Devices

Valves

Boilers are designed to operate at certain maximum pressures. If the operating pressure is exceeded, the boiler may explode. Therefore, all boilers are equipped with at least one or more safety valves. Safety valves will open, releasing steam if the pressure in the drum becomes too high.

In a safety valve, a compressed spring holds a disc snugly against a seat (Figure 4-6). When the pressure against the disk exceeds a preset limit, the safety valve pops open—causing the disk to move away from the seat. The pressure at which the valve opens can be changed by adjusting the compression spring. When a safety valve opens, it discharges, or blows, steam until the pressure of the boiler decreases to a preset amount. The valve then shuts back into its normal seating arrangement. The pressure difference between the popping pressure and the closing pressure is called *blowback*. The valve must be properly adjusted for sufficient blowback or the valve will leak slightly after popping. Blowback can be adjusted by raising or lowering a ring around the valve seat. Safety valves can also be popped manually by using hand levers. For large boilers, each superheater and reheater will have one or more safety valves. The safety valves are located near the outlets of these tube sections.

If a boiler has several valves, they are set to pop at different pressures. The first valve should open when the pressure exceeds a value approximately 3 to 5% above the boiler operating pressure. The other valves will open at pressures slightly above the first valve, usually 10 to 15 psi (TPC Training Systems).

Safety valves should be checked on a regular basis to make sure that they operate properly. They should be maintained to prevent an accumulation of scale or dirt that would interfere with safe operation.

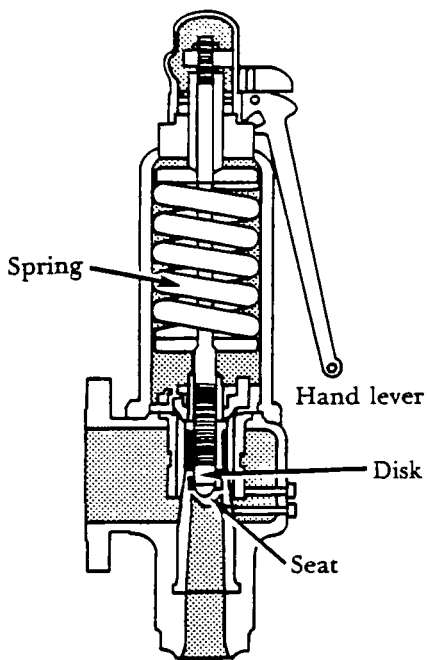


Figure 4-6. Safety valve.

Flame Detectors

Flame detectors, or scanners, monitor burner flames on all boilers and ignitors on coal- and oil-fired boilers. If the flame in a burner or ignitor goes out, a flame detector sends a signal to the fuel feed controls that automatically stop the flow of fuel into the boiler. Thus, the boiler is prevented from operating or igniting while explosive conditions in the furnace exist.

Three flame detectors used on boilers are photocell, ultraviolet, and infrared detectors. Photocells detect visible light, ultraviolet sensors detect ultraviolet light, and infrared sensors detect infrared light in the burner flame or ignitor. These devices are installed in the furnace wall as shown in Figure 4-7.

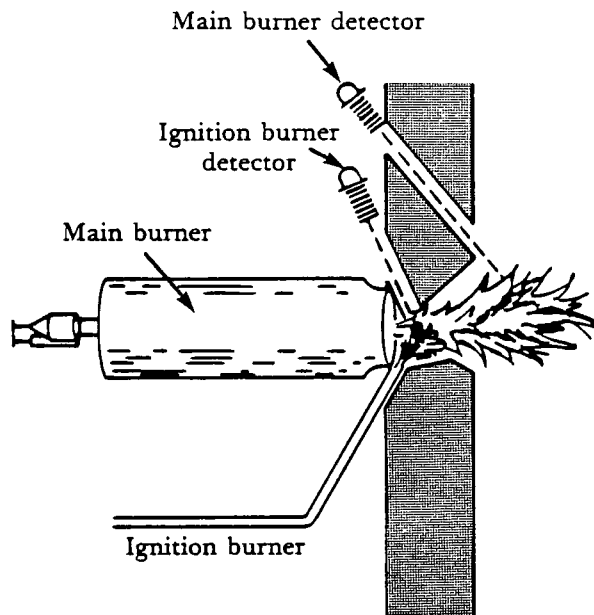


Figure 4-7. Location of flame detectors.

Combustion Controls

Combustion controls are used to adjust the amount of air and fuel supplied to the furnace to respond to the changes in boiler steam pressure. Three combustion controls are on-off, positioning, and metering.

On-off controls, the simplest, are used on fire-tube and small water-tube boilers. A change in steam pressure activates a pressurestat or mercury switch to start the stoker, the oil burner, or gas burner and the forced-draft fan. The on-off control system supplies a pre-determined amount of fuel and air. The air and fuel ratio can be altered, if necessary, by manually adjusting fuel and air settings on the controls. When the steam pressure builds up again, the controls shut down the fuel and air supplies. On-off controls cannot supply a steady steam pressure because they work on a cyclic basis. The pressure points are set far enough apart to prevent the on-off sequence from being constantly activated. Combustion efficiency is low because the control system can only vary the length of the on and off cycles.

Positioning controls, used on many boilers, are more flexible and can provide better combustion efficiency than can on-off controls. These controls operate on a continuous basis, providing smoother changes in fuel and air feed, allowing the boiler to maintain a more uniform steam pressure. The control system has a master pressure controller that responds to a change in steam pressure. When the steam pressure changes, power units actuate the damper on the forced-draft fan to control air flow and position the fuel valve to regulate the fuel feed. Furnace-draft controllers operate independently of the positioning controls to maintain the furnace draft. Positioning controls operate effectively on boilers having relatively stable steam demands. The amount of air and fuel feed can be adjusted manually to change the

air-to-fuel ratio. These adjustments are required to compensate for boiler load changes, dirty tube surfaces, slagging of fuel on furnace walls, or changes in barometric pressure.

Metering controls are a refinement of positioning controls. As with positioning controls, metering controls also have a master pressure controller that responds to a change in steam pressure. However, the metering control system measures the actual flow of fuel and air. The flow of steam or water is measured to correspond to the amount of fuel fed into the furnace. This can be accomplished by measuring the pressure drop across an orifice, flow nozzle, or venturi. The draft loss across the clean-air side of the combustion air preheater is measured to indicate the air flow through the boiler. The metering controls change the damper and fuel valve positions to maintain the correct air-to-fuel ratio. Metering controls are generally located in a remote station where they can be operated automatically or manually. These control systems allow the boiler to be operated efficiently for wide changes in boiler loads. They can also compensate for changes in the fuel supply and for dirt buildup on the tube surfaces.

Operation

The procedure for operating a boiler will depend on the boiler size, the type of combustion equipment used, the operating pressure of the unit, and the steam requirements. The boiler manufacturer should supply the operator with specific instructions as to how to bring the unit on line, general operating practices, emergencies, and caring for idle boilers.

Bringing the Boiler on Line

A specific startup procedure should be followed to prevent the boiler from being damaged. The boiler should be inspected thoroughly after it is installed to make sure that all manhole and access covers have been replaced and that all scaffolding, ladders, tools, and other equipment have been removed from the inside and outside of the boiler. Fans, dampers, and combustion equipment should be checked for proper operation.

New boilers and those that have accumulated oil and grease must be cleaned with an alkaline solution. The solution is first prepared and then pumped into all boiler tube sections. The boiler is slowly brought on line to approximately one-third of its normal working pressure and left on line for one to three days. In addition to being cleaned with an alkaline solution, large boilers are also cleaned out with an acid solution. After the cleaning cycle is finished, the boilers are flushed out with water. New boilers are then given a hydrostatic test before placing them into service. This test consists of filling the boiler with water and slowly building up to 1½ times the normal working pressure. During the test, all safety valves are removed or blocked off so they will not open.

All boiler valves, vents, drains, and the feedwater regulators should then be checked according to the manufacturers operating procedures. The boiler is then

slowly brought on line while the draft gauges are checked and the fans and dampers are adjusted to establish the correct air flow to and from the boiler. The feedwater regulator is operated and the water level and feedwater-supply pressure are carefully checked. The furnace is slowly fired to prevent excessive temperature differences and resulting unequal expansion of boiler components. Combustion is regulated to bring the boiler up to full operating pressure, usually in approximately 45 minutes for small- and medium-sized boilers and approximately two to three hours for large boilers. Even longer periods may be required for boilers that operate at very high temperatures.

Normal Operation

Operating a boiler is a continuous process. Fuel and air are supplied to produce steam, while waste products of ash and flue gas are discharged. The boiler operator must adjust the flow of these materials to maintain the correct steam pressure. On boilers that do not have automatic controls, the operator must watch the steam gauge and adjust the fuel as is necessary. On automatically-controlled boilers, the change in steam pressure will adjust the fuel feed. However, the operator will still have to check the bed thickness in a coal-fired stoker, and monitor the shape of the flame when pulverized coal, gas, or oil is burned. He will also have to check draft gauges, flue gas analyzers, pressure gauges, thermocouples, damper settings, and ash removal systems and make any necessary adjustments. Instruments and controls should be checked, adjusted, calibrated, and kept in good operating condition.

High combustion efficiency can be achieved by monitoring the flue gas with continuous emission monitors. By measuring the oxygen or carbon dioxide in the flue gas, adjustments for the correct amount of excess air can be made. Too much excess air wastes heat out through the stack. Too little excess air causes a high concentration of combustibles to remain in the ash and smoke and unburned fuel to be discharged from the stack. (Note: operator safety concerns are the overriding factors at low excess air conditions). The operator can use analyzers and draft gauge readings to help keep combustion efficiency high.

The operator will also have to perform certain maintenance functions to keep the boiler operating smoothly. Some of these, such as blowdown and sootblowing, must be done on a regular eight-hour shift basis. Others must be done on a regularly-scheduled basis. Boiler maintenance will be discussed later in the lesson.

Emergencies

Occasionally, emergencies occur and the boiler must be taken off line. An emergency shut-down procedure must be established and all operators should be familiar with it to ensure a safe shut down.

Many boilers are equipped with automatic controls that activate in the event of burner flame out or low water level. Fuel valves automatically close and the boiler is shut down until the difficulty has been corrected. In many large boilers, alarms sound for high and low water levels and the operator must then decide on the appropriate action to be taken.

If the water level becomes low, the operator should make sure that feedwater is added to the boiler. If for some reason the feedwater regulator does not work, the fuel and air feed to the boiler should be stopped. The procedure will depend on the combustion equipment used on the boiler.

Failure in fuel supply, too much primary air, or a disturbance because of improper sootblowing, may cause the flame to blow out in a pulverized-coal-, gas-, or oil-fired boiler. The flame detector will stop the fuel flow to the burner. Fans should be operated to remove combustible fuel and gases from the furnace. Once the corrective action has been completed, fans should be operated for a short time to ensure that no combustibles are present. Natural draft fans have an advantage in that they will operate if a power outage occurs.

Forced-draft and induced-draft fans can fail, safety valves become stuck, and occasionally fires in pulverizers can occur making an emergency shut down imperative. The boiler must be shut down to prevent an explosion from occurring. All plant operators must be ready to initiate safe emergency operating procedures.

Care for Idle Boilers

Boilers must be taken off line for occasional inspection and repairs. Some boilers are only used on a periodic basis to provide heat or steam during colder seasons. When a coal-fired boiler is taken out of service for extended time periods, the coal in the bunkers should be used up before shutting the boiler down. Coal stored for long time periods can be a fire hazard.

The normal procedure for removing boilers from service involves reducing the fuel feed and slowly decreasing the steam pressure. All drain connections should be opened and the feedwater valve should be closed. The boiler should be allowed to cool down slowly to prevent injury because of rapid contraction of metal and refractory materials. All tube sections should be washed out to remove any sludge deposits. Boilers that will be out of service for short time periods can be filled up with an alkaline solution and deaerated water. This will allow the boiler to be ready to be brought back on line, after it is quickly drained and filled with water. Boilers taken out of service for extended time periods should be flushed with water and permitted to thoroughly dry. Containers of unslaked lime or dessicant are then placed in the boiler to absorb any moisture from the air in the confined space. Boilers prepared for storage in these two ways can be returned to service by restoring the water level and bringing the unit on line by the normal startup procedure.

Maintenance

All boilers operate more efficiently when they are properly maintained. Maintenance schedules vary depending on the boiler component and its location. Boiler tube sections, boiler drums, and heat recovery equipment must be kept free of soot and scale to provide good heat transfer and adequate cooling to tube surfaces. Boiler auxiliary systems such as pumps, fans, valves, and motors must be maintained to operate

properly. Boiler manufacturers should provide guidelines to the suggested maintenance schedules and procedures.

Sootblowing

Sootblowing removes soot and ash from the fire-side of boiler tubes and heat recovery equipment. These deposits insulate tube surfaces reducing boiler efficiency. They can also erode and corrode metal surfaces, particularly if fly ash is sharp and contains sulfates and acids. The amount of soot and ash deposited on tube surfaces depends on the content and fusion temperature of the ash in the coal burned, and the combustion efficiency in the furnace. A large amount of ash is produced from burning coal; burning oil produces less, while burning gas produces almost no ash. Hand lances and sootblowers remove soot and ash (slag) from tube surfaces by blasting jets of air or steam against the tubes, while the furnace is on-line. Most large boilers use sootblowers, the two common types being rotary and retractable.

In a rotary sootblower, air or steam flows through a tube, or arm, and discharges at a very high speed through nozzles. The nozzles are spaced to blow steam or air directly into each boiler tube as the arm rotates. In a retractable sootblower, the blower is located outside the furnace. The blower moves in and out of the furnace and can reach far inside a boiler to clean superheaters, reheaters, and economizers.

Sootblowing is done at least once a day and occasionally more often. The time between sootblowings depends on the type of fuel burned and how quickly the tube sections become dirty. An increase in the flue gas temperature exiting the boiler or an increase in pressure drop across the tube sections are good indicators that tubes are dirty. If tubes quickly become dirty again after sootblowing, the operator should check the air-to-fuel ratio. There may be too little air to burn the fuel completely, thus forming soot.

When a boiler is down for service, boiler tubes can be cleaned by washing them with water. Hard slag deposits can be removed by carefully chipping them off with a chisel.

Water Treatment

Boiler feedwater must be treated before it can be used. Suspended solids, dissolved minerals, and dissolved gases can cause corrosion and scale in boiler tubes and affect the quality of steam produced.

Minerals dissolve in water as ions that carry an electrical charge. The ions increase the electrical conductivity and hardness of the water, both of which can damage boiler tubes. Increased electrical conductivity rapidly corrodes metal surfaces. High levels of hardness in the water cause scale and sludge to form on tube surfaces. Boiler feedwater can be treated by softening methods.

Water hardness results when mineral salts of magnesium and calcium dissolve in water. These salts can be removed by using chemical softeners or ion exchangers. Chemical softeners are vessels where soda ash or lime react with dissolved salts to form solid precipitates. The solids settle in the bottom of the vessel while softened water passes through a filter to remove only remaining solids. Ion exchangers are vessels containing a thick bed of grainy material called resins. Hard water flows

through the bed where the resin absorbs the hard ions and replaces them with harmless ions. When the resin bed no longer absorbs hardness ions, the bed is regenerated with a strong salt solution to replenish its supply of harmless ions. Another ion exchange process, called demineralization, uses two ion exchange beds, one containing acid, the other containing a caustic soda solution. These systems are designed to produce very pure water.

The measure of the concentration of hydrogen ions in water is called pH. It has a numerical value on a scale of 0 to 14. A pH of less than 7 indicates acidic water and a pH of greater than 7 indicates alkaline water. Boiler feedwater should have a pH of 8.5 to 11.5. Water with low pH values can corrode boiler tubes. Water from lakes and streams that is used in many boilers has a pH ranging from 6.0 to 8.0. The pH of this water may be raised by adding chemicals such as ammonia, phosphates, or caustic soda to boiler feedwater.

Dissolved oxygen in feedwater eats away at the metal, weakening boiler tubes, drums, and piping. One way to remove dissolved oxygen is by using a deaerating heater. Many deaerating heaters consist of trays stacked inside a vessel. Water enters the top of the vessel and flows down through the trays. Steam heats the water as it flows through the vessel causing most of the dissolved oxygen to leave the heater with the steam. Heated, deaerated water is sent to a storage tank where chemicals such as sodium sulfite or hydrazine are added to remove any oxygen still remaining in the water.

Evaporators are also used to remove dissolved impurities from water. An evaporator consists of a steam coil in a tank. Water is fed into the tank and heat, supplied by the steam coil, causes the water to boil. Water leaves the evaporator as a vapor leaving the impurities behind. The vapor enters a heat exchanger where it condenses as pure, distilled water. The sludge left in the evaporator is removed from the bottom.

Boiler feedwater is constantly tested to determine its purity. Impurity tests include checks on dissolved oxygen, silica content, hardness, pH, and conductivity. These tests can be done manually or by using automatic monitoring devices. Even small amounts of impurities in the water can damage boiler equipment and reduce efficiency.

Blowdown

As a boiler generates steam, any impurities in the water become concentrated in the boiler water. As these concentrations increase, they can cause corrosion, scale, or possibly boiler tube failure. A procedure called blowdown reduces the impurity levels (solids) in boiler or cooling water. Blowdown consists of removing water containing a high level of impurities and replacing it with high quality water. Blowdown can be done on a periodic or continuous basis.

In periodic blowdown, a main blowdown, or blowoff, valve is opened allowing water to drain out of the system. This is usually done when the steam demand is low. Most boilers have the blowoff valve connected to the lower, or mud, drum. In cooling towers, blowdown involves opening a blowoff valve that is located in the basin on the tower.

In continuous blowdown, a small amount of water from a boiler or cooling tower is constantly removed. Continuous blowdown valves are usually located in the steam drum. Makeup water that replaces the blowdown water is fed to the drum by the feedwater regulator. Blowdown water is sent to heat exchangers to extract useful heat before disposing of it. Heat, from the blowdown water in a heat exchanger, is transferred to makeup water before it enters the economizer.

Water is tested regularly to determine the level of dissolved solids and, thus, the frequency of blowdown. Conductivity meters that measure the electrical conductivity of the boiler water are used to determine blowdown frequency.

Scale Removal

Scale forms on the inside of tubes in a water-tube boiler and on the outside of tubes in fire-tube boilers. Scale insulates tubes, reducing heat transfer and thus efficiency. As the heat transfer decreases, the metal tubes become hotter. If the temperature becomes too high, the tubes can overheat and eventually rupture, or burst.

Scale formation can be reduced by using water softeners, demineralizers, and evaporators. These devices remove most of the materials that cause scale. However, not all of the minerals are always removed and scale deposits will form in boiler tubes. Scale deposits should be removed as soon as possible. Scale can be removed by internal cleaning while the boiler is on line or by mechanical or acid cleaning when the boiler is down.

For internal cleaning, chemicals such as phosphates are added to boiler water. Phosphate salts react with scale to form sludge. Sludge is removed during blowdown. Mechanical cleaners remove scale from boiler tubes when the boiler is shut down. Mechanical cleaners are power-driven units that contain a cleaning head, a hose, and a motor driven by steam, air, or water. The cleaning head for removing scale from a fire-tube boiler is called a knocker and is shown in Figure 4-8a. The knocker head has lobes that tap the inside of the tube as the cleaner moves through the tube. Mechanical cleaner heads used on water-tube boilers are called cutter heads. The cutter head has several cutting elements made of hard steel (Figure 4-8b). The head is rotated at high speed, pressing the cutter against the tube to remove the scale.

Acid cleaning can also remove scale from boiler tubes and drums. The cleaning solutions consist of acids, such as hydrochloric acid, and other materials called inhibitors to reduce the attack of acid on the metal. The cleaning solutions circulate or soak in the boiler for a few hours. When the cleaning cycle is complete, the boiler is flushed with alkaline and water solutions to remove any traces of acid. Acid cleaning has some advantages over mechanical cleaning in that it requires much less down time to clean the boiler, and it can clean areas and tubes where mechanical cleaners are difficult to reach.

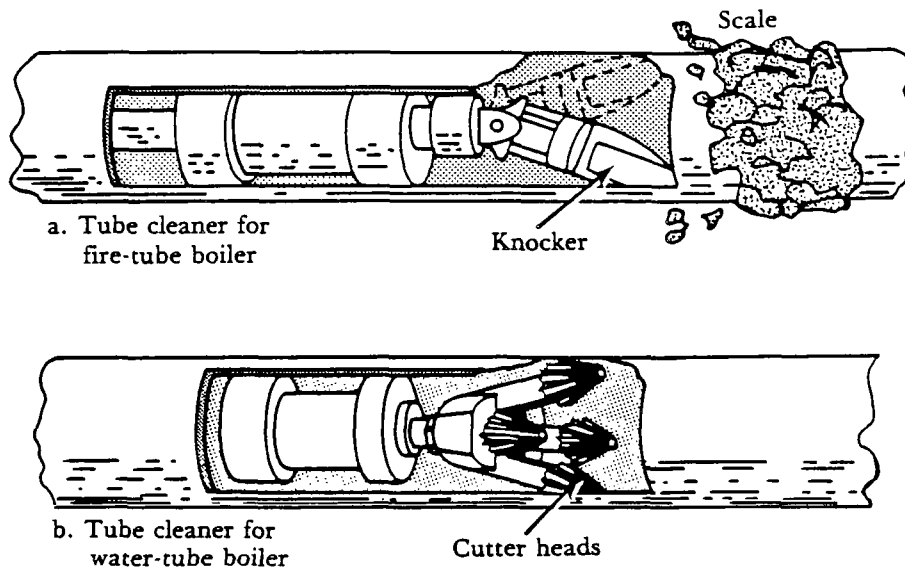


Figure 4-8. Cleaning heads for fire-tube and water-tube boilers.

Boiler Auxiliaries

Pumps, valves, safety valves, controls, compressors, and fans are among the many boiler auxiliaries that must be maintained regularly. Pumps require lubrication to keep the bearings from overheating, rusting, or corroding. Pumps can leak around the packing gland. The packing can be tightened somewhat to help stop leaks. Valves should be checked for correct operation and leaks. Valves tend to leak around the valve stems and packing and may need to be repacked occasionally. All moving parts on a valve should be lubricated. Compressors must be lubricated to protect cylinders from heat and wear. If the compressor has its own lubricating system, the oil level should be checked daily, and the oil changed when dirty. Intake filters must be checked and replaced when they become filled with dust. Water jackets and intercoolers should be inspected to make sure they do not become plugged. Fan blades need to be inspected for excessive wear when they are out of service. Dust deposits in the fan housing and ducts should be removed. Dampers should be moved manually to make sure they move freely and close completely. The bearing oil reservoir level should be checked and oil added if necessary.

These are a few of the maintenance functions that must be performed to keep the boiler operating smoothly. The maintenance crew should have a checklist and logsheet for each boiler component. Inspection frequencies and preventive maintenance practices should be established for all boiler equipment by the vendors.

Summary

This lesson briefly reviewed boiler operation and maintenance. Boilers can be complicated systems and operators and maintenance persons should be properly trained on all aspects of the boiler equipment that they will be operating or maintaining.

Review Exercise

1. Most boilers use _____ to indicate the water level.	
2. _____ are used to sound alarms when the water level in a boiler is low. a. Gauge glasses b. Water columns c. Fusible plugs	1. water columns
3. True or False? Bourdon pressure gauges can measure pressures of steam, air, oil, and water.	2. c. Fusible plugs
4. _____ are commonly used to measure air flow pressures and pressure differences between two points. a. Bourdon gauges b. Manometers c. Fusible water columns	3. True
5. Feedwater regulators are automatic controls that a. regulate the amount of water that is sent to the cooling tower. b. adjust the water level in the boiler. c. adjust the water level in the condenser.	4. b. Manometers
6. A three-element feedwater regulator responds to changes in a. water level, water flow, and steam flow. b. air flow, water flow, and water level. c. steam level, water flow, and air flow.	5. b. adjust the water level in the boiler.
7. In a boiler, headers are used to a. collect condensed steam. b. release steam if the pressure becomes too high. c. transport water and steam.	6. a. water level, water flow, and steam flow.
8. All boilers are equipped with _____ that are used to release steam if the _____ in the boiler becomes too high. a. blowdown valves, water temperature b. safety valves, pressure c. steam traps, pressure d. all of the above	7. c. transport water and steam.
	8. b. safety valves, pressure

9. In a safety valve, the pressure difference between the popping pressure and closing pressure is called _____. a. blowdown b. pressure drop c. blowback	
10. Most boilers use flame detectors to a. detect and adjust the length of the flame. b. detect the presence of a flame and thus prevent the boiler from operating or igniting while explosive conditions in the furnace exist. c. measure and adjust the flame profile, thus ensuring complete combustion conditions.	9. c. blowback
11. Boilers are cleaned with _____ to remove accumulated oil and grease before bringing them on-line. a. alkaline solutions b. alkaline solutions and acid solutions c. alkaline solutions, acid solutions, and water	10. b. detect the presence of a flame and thus prevent the boiler from operating or igniting while explosive conditions in the furnace exist.
12. Ash and dust that deposit on the outside surface of boiler tubes can be removed while the boiler is on-line by _____. a. sootblowing b. blowdown c. knocker heads d. all of the above	11. c. alkaline solutions, acid solutions, and water
13. Sootblowers remove ash and soot from boiler tube surfaces by a. scraping boiler tubes with wire brushes. b. blasting jets of alkaline solution against the tubes. c. blasting jets of air or steam against the tubes.	12. a. sootblowing
	13. c. blasting jets of air or steam against the tubes.

14. If the flue gas temperature at the stack exit _____ or the pressure drop across tube sections _____ it is likely that boiler tubes are dirty and sootblowing should be initiated. a. decreases, increases b. increases, decreases c. decreases, decreases d. increases, increases	
15. True or False? Water hardness results when mineral salts of magnesium and calcium dissolve in water.	14. d. increases, increases
16. What should be the pH of boiler feedwater? a. 5.0 to 7.0 b. 8.5 to 11.5 c. 11.5 to 14.0	15. True.
17. Hardness can be removed from water by a. adding lime or soda ash to the water. b. using ion exchangers. c. using demineralizers. d. all of the above	16. b. 8.5 to 11.5
18. True or False? Boiler feedwater should contain a high concentration of dissolved oxygen.	17. d. all of the above
19. A procedure called _____ reduces the impurity levels (solids) in boiler water and cooling water by periodically removing water from the boiler or cooling tower. a. sootblowing b. deaerating c. blowdown	18. False.
20. Scale can be removed from boiler tubes by using mechanical cleaners. _____ are used for cleaning fire tubes, while _____ are used for cleaning water tubes. a. Blowdown valves, retractable sootblowers b. Cutter heads, knocker heads c. Knocker heads, cutter heads	19. c. blowdown
	20. c. Knocker heads, cutter heads

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Lesson 5

Steam Turbines, Condensers, and Cooling Towers

Lesson Goal and Objectives

Goal

To familiarize you with the operation of a turbine used to produce electricity and with the operation of auxiliary equipment in a power plant.

Objectives

Upon completing this lesson, you should be able to—

1. describe the operation of a turbine in producing electricity,
2. recall the location of condensers in a power plant and the reason they are used,
3. recognize two types of cooling towers and the difference in their operation, and
4. recall the locations of steam turbines, condensers, cooling towers, feedwater heaters, and reheaters in a complete steam generation system.

Introduction

Boilers produce steam for many different purposes. Some industries design their facilities to use steam in the processes, to heat the facility during colder months, and occasionally to generate electricity for in-plant use. Utilities use steam to drive large turbines that generate electricity. The design and complexity of a boiler system will vary depending on the size and ultimate use of the steam produced by the boiler.

Steam Turbines

Steam contains a tremendous amount of heat energy. Heat energy is transformed into mechanical energy to drive a steam turbine. The turbine in turn rotates a generator which changes the mechanical energy into electrical energy, or electricity.

A steam turbine has two main parts—the cylinder and the rotor. The cylinder, or stator, is made of steel or cast iron and contains the fixed blades, vanes, or nozzles that direct steam into the movable blades. The rotor is a shaft that carries the

movable blades. High-temperature, high-pressure steam enters one end of the turbine through an inlet valve into the steam chest. The steam chest contains control valves that regulate the flow of steam into the turbine. Steam flows through a set of stationary blades, or nozzles. As the steam passes through the nozzles, it expands in volume, and its velocity increases. The steam moving at high velocity strikes the first set of moving blades, causing the shaft to rotate (Figure 5-1). The steam enters the next set of fixed blades and then into the set of moving blades, continually causing the shaft to rotate.

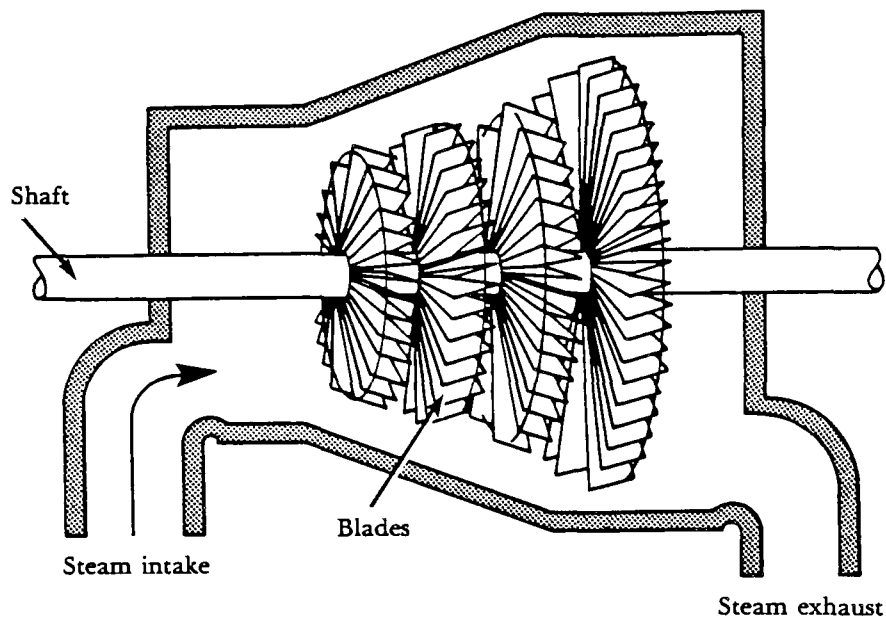


Figure 5-1. Typical steam turbine.

As the steam moves through the turbine its pressure and temperature decrease, while its volume increases. A pound of steam will expand over 800 times its original volume as it moves from the steam header through the turbine. The turbine, therefore, increases in diameter from the inlet to the outlet. This allows the volume of steam to increase as it moves through the turbine without reducing the efficiency of the system.

A turbine that uses the impact force of a steam jet on the blades to turn the shaft is called an *impulse turbine*. Its action is analogous to that occurring with a windmill. As the wind strikes the blades, the impact force causes the windmill to turn. The harder the wind blows, the faster the windmill blades will turn. The steam flow through the blades in an impulse turbine is shown in Figure 5-2. Steam expands as it passes through the nozzles where its pressure decreases and its velocity increases. As steam flows through the moving blades, its pressure remains the same and its velocity decreases because the steam does not expand here. The nozzles, or fixed blades, expand the steam again as the steam moves into the next stage. The pressure decreases in each stage as the steam expands through the fixed blades.

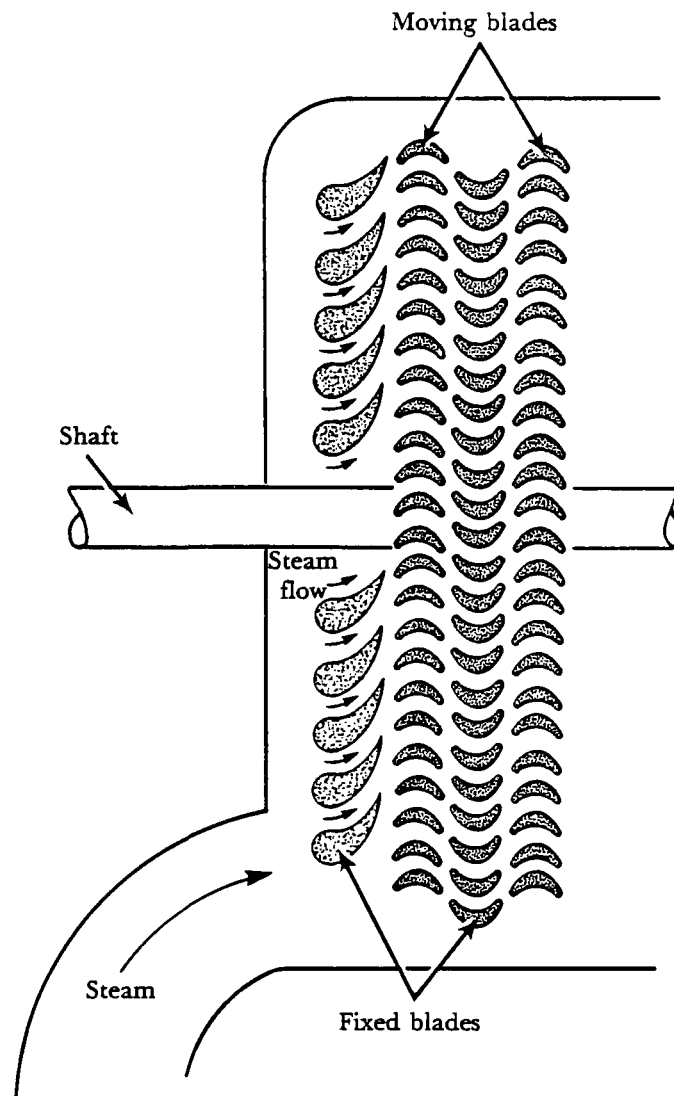


Figure 5-2. Steam flow through the blades of an impulse turbine.

In a *reaction turbine*, the pressure decreases and the velocity increases while the steam flows through both the fixed and moving blades. The action is analogous to the kickback that an individual receives when shooting a shot gun. The reaction turbine uses the kickback force from the steam as it leaves the moving blades to rotate the shaft. All of the blades are the same shape and therefore act like nozzles (Figure 5-3).

Many utilities use turbines that have both impulse and reaction blade arrangements. These turbines usually have impulse blades at the high-pressure end and reaction blades at the low-pressure end of the turbine. The length and size of the blades increase from front to back to use the expanding steam efficiently.



Figure 5-3. Steam flow through the blades of a reaction turbine.

Large steam turbines usually have high-pressure, intermediate-pressure, and low-pressure sections (Figure 5-4). Steam, from the superheater, goes to the main steam header. It flows into the high-pressure section of the turbine, rotates the shaft, and loses some of its pressure and temperature. The steam then goes back to the boiler where it is heated in the reheater. Steam flows from the reheater to the intermediate-pressure turbine where it turns the rotor. Part of the steam is extracted from the intermediate-pressure turbine and is used to heat water in the boiler feedwater heaters. The rest of the steam flows through a crossover pipe to the low-pressure turbine and continues to turn the rotor. In the low-pressure turbine, the last bit of work is extracted from the steam. Some steam from the high-pressure and low-pressure turbines is also extracted to heat boiler feedwater. The spent steam from the low-pressure turbine is sent to the condenser.

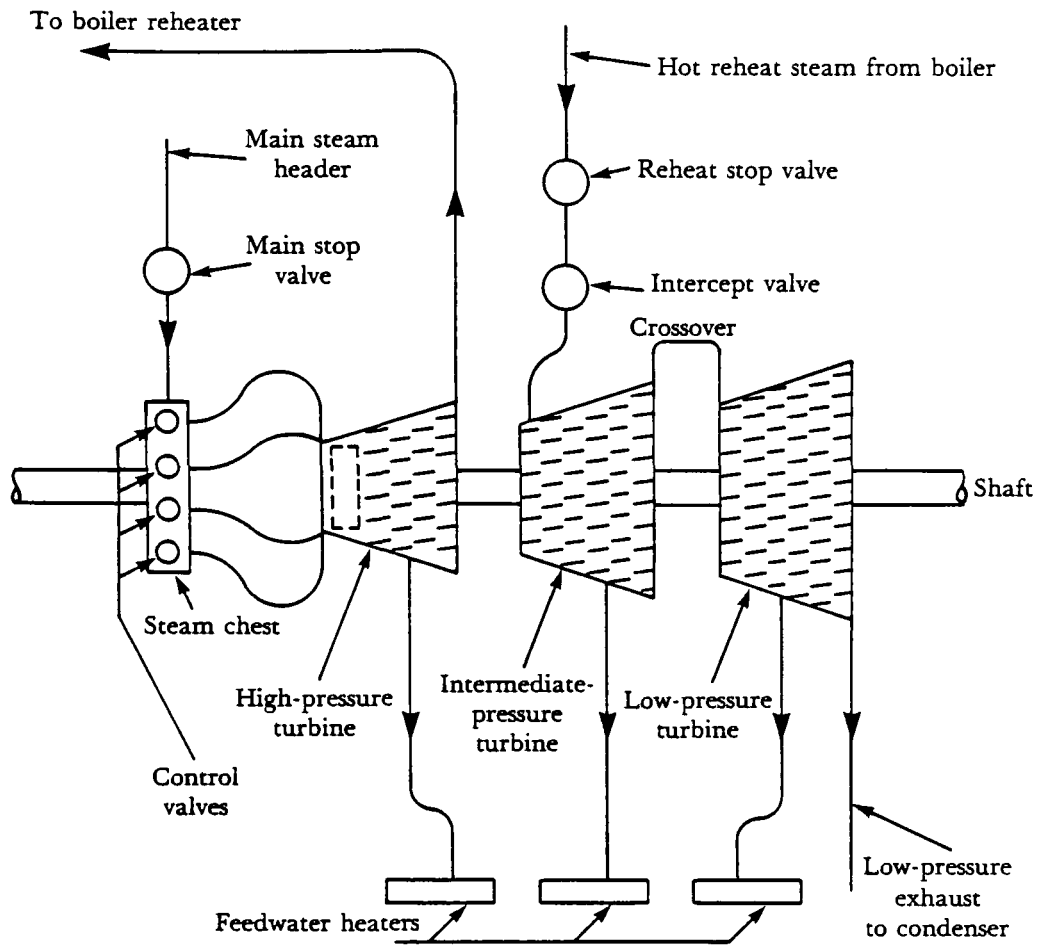


Figure 5-4. Steam flow through high-pressure, intermediate-pressure, and low-pressure turbines.

The shaft arrangements can be single, tandem-compound, and cross-compound as shown in Figure 5-5. A single turbine consists of one steam turbine coupled to a generator. In a tandem-compound turbine, a high-pressure turbine and a low-pressure turbine are joined to a common shaft that is coupled to a single generator. In a cross-compound turbine, a high-pressure and an intermediate-pressure turbine are joined to a common shaft and a low-pressure turbine is on a separate shaft. Each shaft drives its own generator.

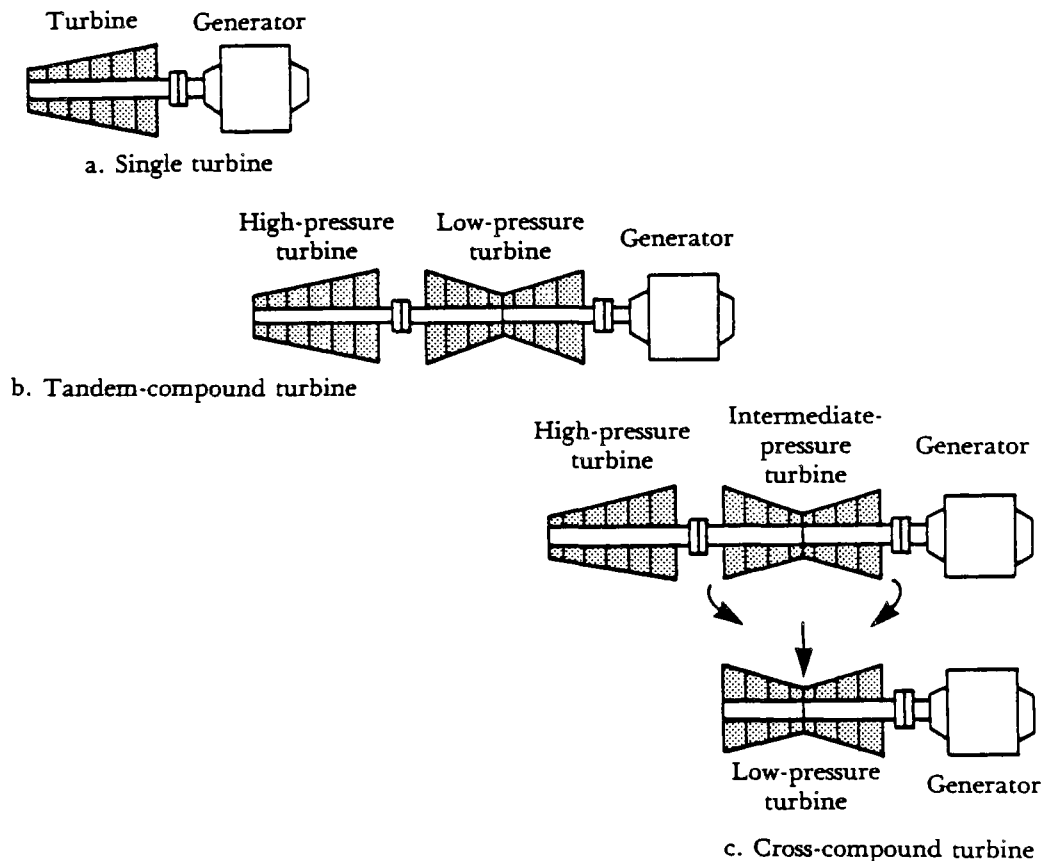


Figure 5-5. Turbine and generator shaft arrangements.

Condensers

Condensers are used in connection with steam turbines for two reasons: (1) to produce a vacuum at the turbine exhaust and (2) to recover the condensate, condensed steam, so it can be used again. Because condensed steam is pure distilled water, it is very suitable for use as boiler feedwater. Condensed steam, at the turbine exhaust, produces a vacuum to remove the back pressure that would otherwise hinder the flow of steam from the turbine. Because the condensed steam is at a lower temperature than the exhausted steam, the overall efficiency is increased.

Two types of condensers are the direct contact and indirect contact. In a *direct contact* condenser, steam is mixed with sprays of cooling water (Figure 5-6). The cooling water condenses the steam and both are collected at the bottom of the vessel, called the hotwell. Few power plants use direct contact condensers because the cooling water, usually pumped from nearby lakes, rivers, or ponds, contaminates the pure condensed steam. Thus, the condensate is unsuitable to be used as boiler feed-water without first being treated extensively.

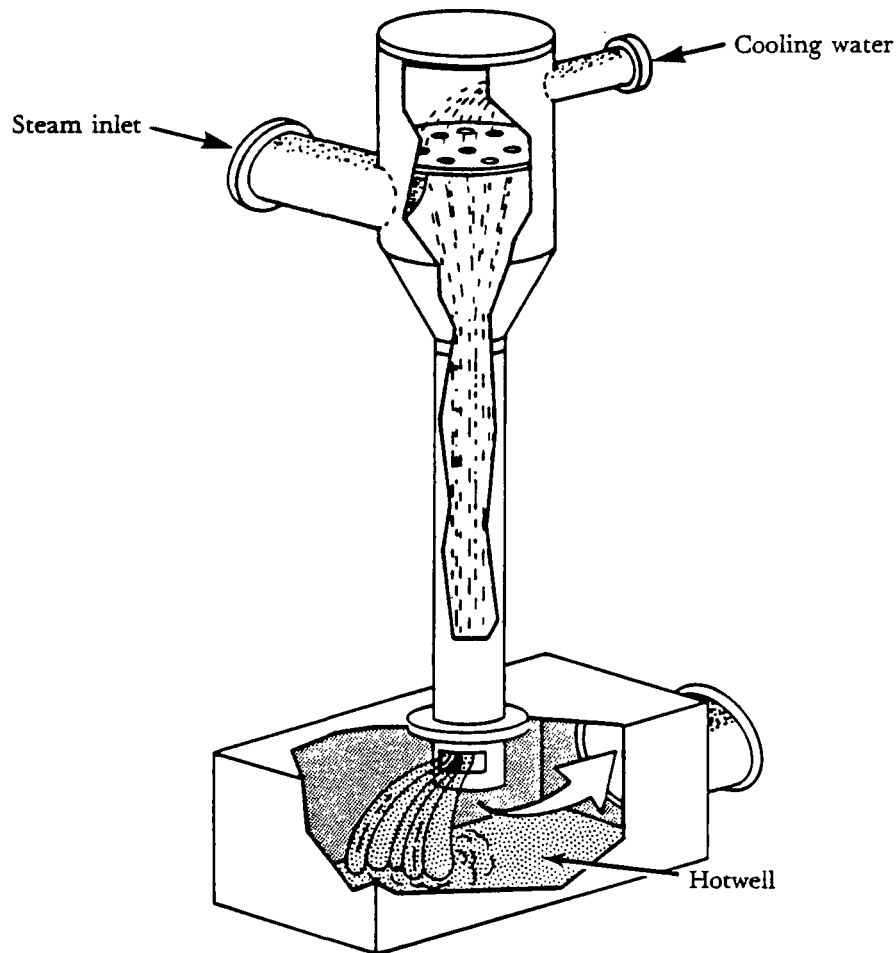


Figure 5-6. Direct-contact condenser.

Most power plants use indirect, or surface, condensers, commonly called shell-and-tube heat exchangers. The surface condenser is a closed vessel containing many small-diameter tubes (Figure 5-7). Cooling water passes through individual tubes while steam flows over and around tube bundles. Condensed steam collects at the condenser bottom or hotwell. The condensate is pumped from the hotwell, through the feedwater heaters, into the economizer, and finally back into the boiler steam drum where the cycle begins again. Depending on the design, the cooling water can make one or more passes through the tubes before being discharged. Warmed cooling water is returned to the rivers or lakes or is sent to a cooling tower. Because the

cooling water does not actually come in contact with the steam, the pure condensed steam is not contaminated as it is in the direct contact condenser.

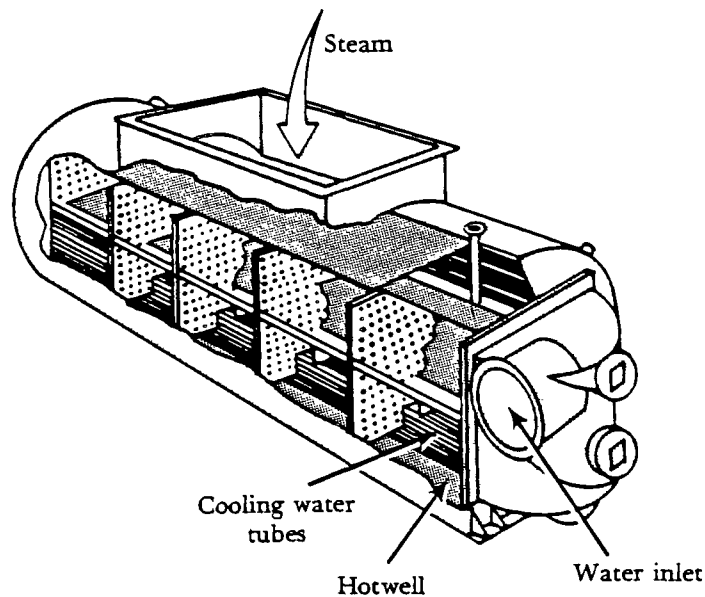


Figure 5-7. Surface condenser.

Condensers require large quantities of cooling water. A condenser uses approximately 9 to 12 gallons of water (75 to 100 lb) to condense each pound of steam (TPC, 1975).

The water pumped from nearby rivers, lakes, and streams passes through intake screens located at the water source to remove sticks, leaves, and other suspended solids from it. Screens can become plugged, and therefore, must be periodically checked and maintained to remove collected debris. Otherwise, waterflow to the condenser may be restricted.

Condenser tubes become dirty after continual use. Tube fouling occurs when scale, slime, and algae collect on the inside of the tubes. These deposits can reduce both heat transfer and water flow through the condenser. Tubes can be cleaned by using a hydraulic gun, chemicals, or backwashing. In the hydraulic gun technique, rubber plugs are shot by water jets through the condenser tubes. The rubber plugs rub against the tube walls to remove slime and soft scale. In chemical cleaning, chlorine or chlorine compounds are added regularly to the water supply. The chlorine dissolves algae and reduces slime buildup. In backwashing, the water flow through the condenser is reversed, flushing out the tubes.

Cooling Water Systems

The cooling water system through the condenser can be a once-through or a recirculating system. Water is pumped from the source and flows through large pipes or channels. The intake of the pipe has a screen or a set of closely-spaced bars to prevent solids from entering the pipe. Water is pumped through the condenser and is

returned to the source with an increased temperature occasionally as high as 20°F above the water source's temperature. This can cause thermal pollution to the water source, possibly injuring fish and other organisms.

Power plants having limited water supplies or those with high-temperature return water from the condenser use a recirculating cooling water system. This system uses one or more cooling towers to remove heat from the warmed cooling water and returns the water to the condenser. A recirculating system only requires a small amount of additional cooling water (approximately 5 to 10%) to replace any losses that occur during the cooling operation.

One type of cooling tower, a mechanical draft tower, uses either a forced-draft fan that is located at the bottom of the tower or an induced-draft fan that is located at the top of the tower. In a tower using a forced-draft fan, air is blown up through the tower while the warm water from the condenser is sprayed at the top of the tower. Water descends over wood, ceramic, or fiberglass slats and collects in a basin at the tower bottom. In an induced-draft cooling tower, air enters louvers in the side of the tower and is pulled upward by the fan (Figure 5-8). In both of these towers, the water temperature decreases as water evaporates and heat is transferred to the air. A pump in the basin returns cooled water back to the condenser.

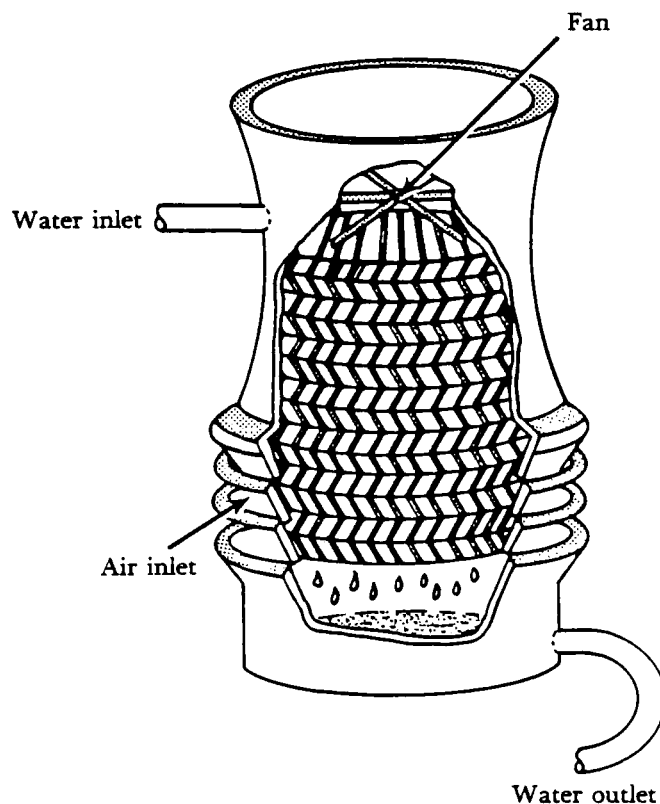


Figure 5-8. Induced-draft cooling tower.

A hyperbolic natural-draft cooling tower is shown in Figure 5-9. Water is sprayed at the tower top and falls over slats of wood, ceramic, or fiberglass contained in the

tower. Air enters the bottom of the tower and rises up through the tower because of the natural draft. Cooled water collects in a concrete basin and is returned to the condenser.

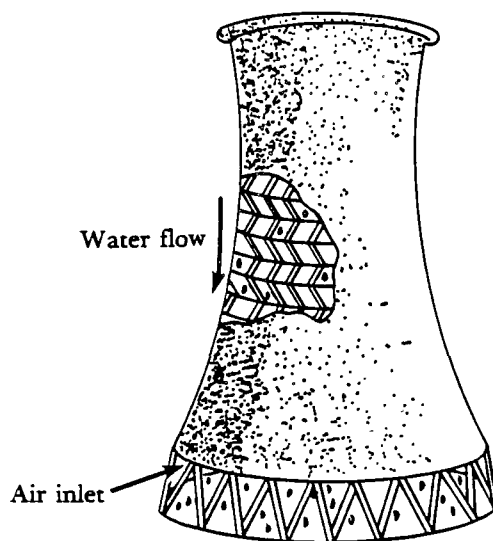


Figure 5-9. Hyperbolic natural-draft cooling tower.

In cooling towers, the dissolved solids concentration increases as the cooling water evaporates. Buildups of minerals in the water can cause scale, corrosion, and plugging in the condensers, pumps, and piping. Scale formation can be reduced by adding phosphates to the water. Phosphates react with scale-forming impurities precipitating them into a sludge. The sludge settles in the tower basin and is removed during blowdown. Phosphates can cause algae to grow, but the algae growth can be controlled by adding chlorine. The pH of the cooling water can be adjusted by adding either sulfuric acid or lime. Dissolved oxygen in the cooling water can be reduced by adding corrosion inhibitors.

Summary

This lesson briefly covered steam turbines, condensers, and cooling towers. A complete steam generation system that generates electricity contains a boiler, turbine, generator, and auxiliary equipment. Figure 5-10 shows the schematic diagram of a coal-fired boiler system.

Pulverized coal is fed into the burners of the boiler by a forced-draft fan. Steam produced in the boiler tubes collects in steam drums where moisture is removed by separators. Steam is then sent to the superheater where it is further heated. High-pressure, high-temperature steam leaves the superheater through steam headers. Steam enters the steam chest in the turbine where control valves regulate the flow through the turbine. The high-pressure turbine, containing fixed and moving vanes, is turned as the high-pressure steam strikes the blades. Steam is exhausted from the

high-pressure turbine and piped back to the reheat section of the boiler to be heated again. Reheated steam flows through the intermediate-pressure turbine and/or the low-pressure turbine. Some steam is extracted from the turbines to heat boiler feedwater in the feedwater heaters. Boiler feedwater is further heated in the economizer before it flows to the steam drum as makeup water. Steam is exhausted from the low-pressure turbine into the condenser to create a vacuum and to condense steam into high quality water to be used again in the boiler. Condenser cooling water is cooled by using cooling towers. Fresh makeup water for the boiler is treated by chemicals and by an evaporator or demineralizer before it goes to the feedwater heaters. Flue gas produced in the boiler goes through the boiler tube sections, the economizer, air preheater, and finally through air pollution control devices to remove pollutants before it enters the atmosphere.

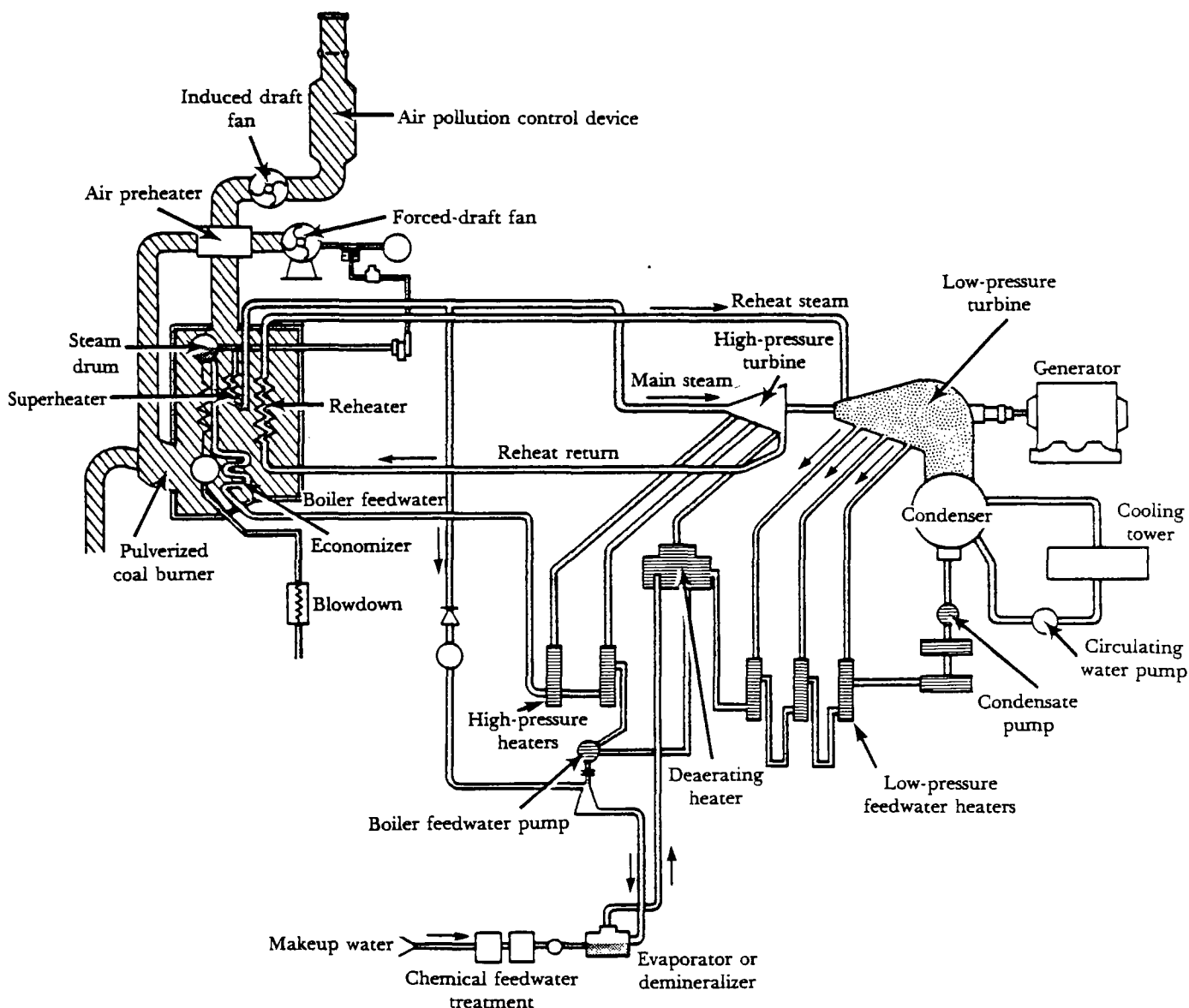


Figure 5-10. Layout of a steam generation system.

Review Exercise

1. High-temperature, high-pressure steam enters a turbine through an inlet valve into the a. steam chest. b. reheater. c. condenser.	
2. In a turbine, fixed or stationary blades are called a. stators. b. nozzles. c. rotors.	1. a. steam chest.
3. As steam moves through a turbine and is exhausted, its pressure _____, its volume _____, and its temperature _____. a. increases, decreases, decreases b. decreases, decreases, decreases c. decreases, increases, decreases	2. b. nozzles.
4. A _____ uses the kickback force from steam as it leaves the moving blades to rotate the shaft. a. impulse turbine b. impact turbine c. reaction turbine	3. c. decreases, increases, decreases
5. In a steam turbine, steam is sent from the high-pressure turbine to the _____ before it enters the low-pressure turbine. a. economizer b. reheater c. superheater d. condenser	4. c. reaction turbine
6. Condensers are used in connection with steam turbines to a. cool water before it is returned to rivers or lakes. b. produce a vacuum at the turbine exhaust. c. recover condensed steam. d. b. and c. above e. all of the above	5. b. reheater
	6. b. and c. above

7. Power plants generally use _____ so that cooling water is not contaminated. a. direct contact condensers b. spray ponds c. surface condensers	
8. Cooling towers that use fans located in the top of the tower are called a. hyperbolic natural-draft towers. b. induced-draft towers. c. forced-draft towers.	7. c. surface condensers
9. In cooling towers, the water temperature decreases as the water _____, thus transferring heat to the air. a. condenses b. evaporates c. diffuses	8. b. induced-draft towers
10. In cooling towers, dissolved solids can be removed by a. blowdown b. blowback c. deaerators	9. b. evaporates
	10. a. blowdown

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Lesson 6

Air Pollution Emissions, Regulations, and Control Techniques for Industrial and Utility Boilers

Lesson Goal and Objectives

Goal

To familiarize you with the air pollution emissions generated in a boiler, the air pollution regulations that limit the amount of pollution that can be emitted from a boiler, and the control techniques used to reduce these emissions.

Objectives

Upon completing this lesson, you should be able to—

1. name three air pollutants emitted from a boiler,
2. recognize two regulations that have been adopted to limit the amount of air pollution that can be emitted from a boiler, and
3. recognize at least three control techniques and equipment used to reduce particulate, SO₂, and NO_x emissions from a boiler.

Air Pollution Emissions

Air pollution emissions generated from burning fossil fuels in a boiler are particulate matter, sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon monoxide (CO). These are emitted in varying amounts depending on the fuel burned and the boiler's operating conditions. A complete listing of emission factors for particulates, SO₂, and NO_x emitted from boilers is given in the EPA publication AP-42.

Particulate Matter

Particulate matter is emitted from a boiler stack when fossil fuel is burned in the furnace. Since coal usually contains a higher content of ash than does fuel oil or gas, the particulate emissions from coal-fired boilers are usually greater than those from oil-or gas-fired boilers. In fact, when natural gas is burned in a boiler, particulate emissions are almost nil. Coal-fired boilers produce different amounts of particulate emissions depending on ash content of the coal and the way the fuel is burned in the furnace. For instance, when coal is pulverized and burned in a pulverized coal-fired

boiler, the particulate emissions are higher than those from an underfeed, overfeed, or spreader stoker boiler. Underfeed, overfeed, and spreader stoker boilers burn a coarser coal than do pulverized coal-fired boilers, resulting in coarser fly ash in the exhaust gas. Emission factors used to estimate particulate emissions from coal-fired boilers are listed in Appendix A.

For fuel-oil combustion, particulate emissions vary depending on the grade and composition of the fuel burned, the type and size of the boiler, and the firing and loading practices. Loading practice refers to the percent capacity—such as 50%, 75%, or 100% of the boiler's rated capacity—at which the boiler is operated. The amount of particulate emissions resulting from burning fuel oil depends mostly on the grade of the fuel burned. Fly ash emissions are greater when burning heavy residual oils (Nos. 5 and 6 grades) than when burning lighter distillate oils (No. 2 grade). Particulate emissions are also a function of the sulfur content when burning residual oil. The higher the sulfur content for residual oil, the higher the particulate emissions generated. This is because high sulfur residual oil contains more ash, sulfur, and heavy organic compounds that are difficult to burn cleanly. Emission factors used to estimate particulate emissions from oil- and gas-fired boilers are listed in Appendix A.

Sulfur Dioxide

Sulfur dioxide emissions occur when the sulfur contained in the fuel is oxidized to SO_2 . Therefore, the lower the amount of sulfur contained in the fuel, the lower the resulting emissions will be when the fuel is burned. Natural gas contains very little sulfur and, consequently, a very small amount of SO_2 is emitted from a gas-fired boiler. Fuel oils contain varying amounts of sulfur in the oil. The heavier oils usually contain more sulfur than do the lighter oils. SO_2 emissions resulting from burning coal will depend on the amount of sulfur contained in the coal. Low sulfur western coal usually has a sulfur content of less than 1% whereas some high sulfur eastern coals contain between 3 and 6% sulfur. The higher the sulfur content in the coal, the larger the amount of SO_2 emitted. Emission factors used to estimate SO_2 emissions from boilers are listed in Appendix A.

Nitrogen Oxide

When fossil fuels are burned in a furnace, nitrogen oxides (NO_x) are formed by two processes. In the first, the nitrogen and oxygen contained in the combustion air react at the high temperatures in the furnace to form nitrogen oxide (NO). In the second, the nitrogen compounds contained in the fuel are oxidized to form NO. The important factors that affect the formation of nitrogen oxides are: flame and furnace temperature, residence time that the combustion products are at the flame temperature, the nitrogen and oxygen content of the combustion air, and the nitrogen content of the fuel that is burned. In large boilers, approximately 95% of the NO_x is in the form of NO, the remainder is nitrogen dioxide (NO_2).

In boilers, nitrogen oxide emissions will vary depending on the fuel burned. If coal is burned, NO_x emissions will be high because coal has a high percentage of

nitrogen and the temperature of the flame is high. For fuel oil, the NO_x emissions will vary depending on how much nitrogen is contained in the fuel oil and also on the conditions in the furnace. NO_x emissions from gas-fired boilers occur mainly because of the high temperatures in the furnace since natural gas contains very little nitrogen. Emission factors used to estimate nitrogen oxide emissions from boilers are listed in Appendix A.

Carbon Monoxide

Carbon monoxide (CO) is formed as a result of the incomplete combustion of the fuel (see Lesson 2). If the boiler is operated properly, the CO emissions will be relatively low regardless of the fuel that is burned.

Emission Regulations*

The Federal government has set standards for pollutant levels in the ambient air. These standards, known as the National Ambient Air Quality Standards (NAAQS), are specified for the following pollutants: sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), nitrogen dioxide (NO_2), particulate matter, and lead. In order that these ambient standards can be attained, industrial source emission standards have also been set. State and local air pollution control agencies have adopted regulations to limit the pollutant concentration that can be emitted. The Federal government has set New Source Performance Standards (NSPS) for industrial sources. Two NSPS for boilers have been promulgated, and a third should be promulgated in late 1985.

New Source Performance Standards for Fossil Fuel-Fired Steam Generators

EPA has promulgated NSPS for fossil fuel-fired steam generators (FFFSG) with heat input greater than 73 MW (250×10^6 Btu/hr). These standards establish particulate, sulfur dioxide, and nitrogen oxide emission limits for steam generators whose "construction commenced" after August 17, 1971 (Table 6-1). This standard is covered under Subpart D, Part 60, Code of Federal Regulations. The Code of Federal Regulations defines a fossil fuel-fired steam generator as a furnace or boiler used in the process of burning fossil fuel (natural gas, oil, coal, or wood) for the purpose of producing steam by heat transfer. This NSPS covers both utility and industrial boilers rated greater than 73 MW (250×10^6 Btu/hr heat input). The term "construction commenced" is defined in the Clean Air Act and does not necessarily mean that actual physical construction was initiated. It may be interpreted as the date that a permit is initiated at the air pollution control agency.

*The majority of the following sections are adapted from Beachler and Joseph, February, 1984.

Emission monitoring requirements are also given in Table 6-1. Continuous emission monitors for monitoring opacity, SO₂, and NO_x emissions are required for all fossil fuel-fired steam generators rated greater than 73 MW (250 × 10⁶ Btu/hr heat input) installed after August 17, 1971. EPA has proposed an amendment to Subpart D to allow fuel sampling or manual stack sampling (modified EPA Method 6) to be used in place of continuous SO₂ emission monitors.

Table 6-1. New Source Performance Standards for fossil fuel-fired steam generators rated greater than 73 MW (250 × 10⁶ Btu/hr heat input). Subpart D, new sources installed after August 17, 1971.

Emissions	Metric units (ng/J)	English units (lb/10⁶ Btu)	Fuel	Emission monitoring requirement
Particulate*	43	0.1	Gas, liquid, solid	—
SO ₂	340	0.8	Liquid (oil)	Continuous
	520	1.2	Solid (coal)	Continuous
NO _x	86	0.2	Gas	Continuous
	130	0.3	Liquid (oil)	Continuous
	300	0.7	Solid (except lignite)	Continuous
*Opacity is not to exceed 20% for periods over six minutes in one hour, and opacity is never to exceed 27% (for burning all fuels).				Continuous

Note: For utility boilers, this standard applies to boilers installed after August 17, 1971 but before September 18, 1978.

New Source Performance Standards for Electric Utility Steam Generators

EPA promulgated NSPS for electric utility steam generators with heat input greater than 73 MW (250 × 10⁶ Btu/hr) for which construction commenced after September 18, 1978 (Table 6-2). This standard is covered under Subpart Da, Part 60, Code of Federal Regulations. The Code of Federal Regulations defines electric utility steam generating unit as any steam generator that is constructed for the purpose of supplying more than one-third potential electric capacity and more than 25 MW electrical output to any utility power distribution system for sale. This standard is more stringent than Subpart D and applies only to utility steam generators.

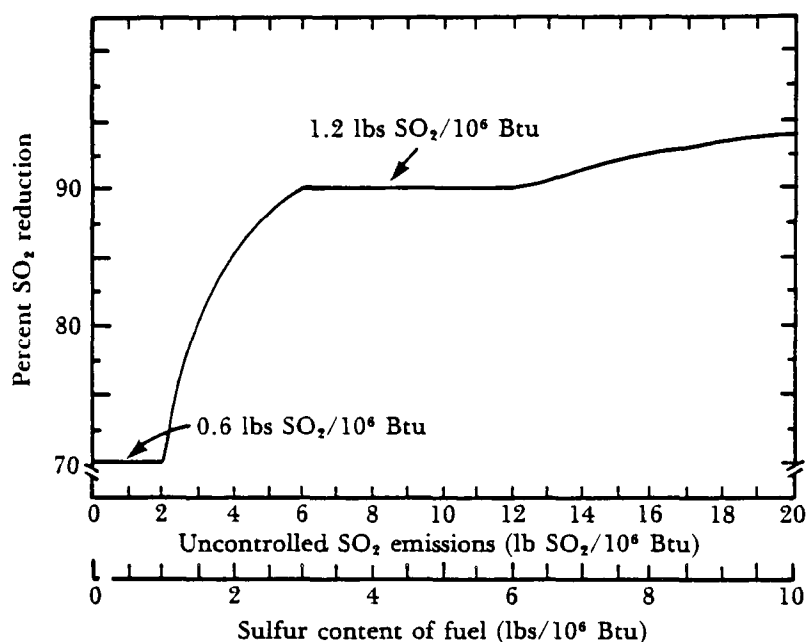
Table 6-2. New Source Performance Standards for fossil fuel-fired steam generators rated greater than 73 MW (250×10^6 Btu/hr heat input). Subpart Da, new sources installed after September 18, 1978.

Emissions	Metric units (ng/J)	English units (lb/ 10^6 Btu)	Fuel	Emission monitoring requirement
Particulate*	13	0.03	Gas, liquid, solid	—
SO ₂	340 and 90% SO ₂ reduction is required unless emissions are less than 86	0.8 0.2	Liquid or gaseous	Continuous
	520 and 90% SO ₂ reduction is required unless SO ₂ emissions are less than 260 then 70% SO ₂ reduction is required • sliding scale is between 70% and 90% as long as emissions (after control) are less than 0.6 lb/ 10^6 Btu	1.2 0.6	Solid (coal)	Continuous
NO _x	86	0.2	Gaseous (except coal derived)	Continuous
	130	0.3	Liquid (except coal derived)	Continuous
	210	0.5	Subbituminous coal	Continuous
	260	0.6	Bituminous/anthracite coal and lignite	Continuous
	340	0.8	Lignite mined in ND, SD, and Montana burned in a slag-top furnace	Continuous
*Opacity is not to exceed 20% for periods over six minutes in one hour, and opacity is never to exceed 27% (for burning all fuels).				Continuous

The NSPS for electric steam generators built after September 18, 1978 requires an SO₂ emission reduction (usually flue gas scrubbing). In boilers burning coal, the SO₂ emissions must be less than 1.2 lb/ 10^6 Btu. Also, a 90% reduction of SO₂ emissions is required for sources burning high sulfur coal. If the emissions are less than 0.6 lb/ 10^6 Btu (coal-fired units) then only 70% SO₂ emission reduction is required. A sliding scale of control is between 70% and 90%, as long as the SO₂ emissions after control are less than 0.6 lb/ 10^6 Btu. Boilers burning low sulfur coal (usually less than 1%) generally have SO₂ emissions less than 0.6 lb/ 10^6 Btu. Some sulfur contained in coal can be removed by coal washing before it is burned. This can enable the plant to meet the standard by partial scrubbing (70 to 90%) as long as the emissions are less than 0.6 lb/ 10^6 Btu. For oil-fired utility boilers, the SO₂ emissions must be less than 0.8 lb/ 10^6 Btu and 90% SO₂ emission reduction (scrubbing) is required, unless the emissions are less than 0.2 lb/ 10^6 Btu. In this case, no scrubbing is required.

For example, a power plant ($> 250 \times 10^6$ Btu/hr) cannot have SO₂ emissions exceeding 1.2 lb/ 10^6 Btu. In addition, the plant is required to reduce the SO₂ emis-

sions by 90%. If the plant's emissions are less than 0.6 lb/10⁶ Btu, then only 70% scrubbing is required. It is possible that the SO₂ emissions will fall between 0.6 and 1.2 lb/10⁶ Btu. In this case, 90% scrubbing is required. It is also possible to meet the NSPS standard by scrubbing 85% if, and only if, the plant's emissions do not exceed 0.6 lb/10⁶ Btu. A useful graphical representation of the 1978 NSPS for sulfur dioxide emission limitations from fossil fuel-fired steam generators (utility boilers) is shown in Figure 6-1.



Source: Beachler and Joseph, 1984.

Figure 6-1. 1978 NSPS for utility boilers—required SO₂ reduction.

A number of economic and energy impacts were considered when EPA decided to set this NSPS standard. One factor that made the variable 70 to 90% control rule attractive was the encouragement to use control technology such as dry FGD scrubbing that can easily remove 70% of SO₂ emissions from flue gas. Another factor was that the rule would encourage the use of locally-available coal and would not create an economic incentive for burning low-sulfur western coal (Costle, 1977).

Emission monitoring requirements were also given in Table 6-2. Continuous emission monitors for monitoring opacity, SO₂, and NO_x emissions are required for all fossil fuel-fired steam generators rated greater than 73 MW (250 × 10⁶ Btu/hr) installed after September 18, 1978.

Proposed New Source Performance Standards for Industrial Boilers

Proposed New Source Performance Standards for industrial boilers were published in the Federal Register on June 19, 1984. The proposed NSPS affects boilers with a heat input capacity of greater than 29 MW (100×10^6 Btu/hr). The draft was published as Subpart Db, Part 60, Code of Federal Regulations. The proposed regulations establish limits for particulate and NO_x emissions from industrial boilers firing coal, oil, natural gas, wood, or solid waste. The proposed emission limits supersede the particulate and NO_x standards given in Subpart D for industrial boilers greater than 73 MW (250×10^6 Btu/hr) heat input. The changes to Subpart D would not be retroactive, and these changes would only apply to new industrial boilers that are "constructed" after June 19, 1984.

There are no SO_2 emission limits included in the proposed standard. The proposed standard does not revise the SO_2 emission limits given in Subpart D for industrial boilers greater than 73 MW (250×10^6 Btu/hr). SO_2 emission limits given in Subpart D still apply. A proposed standard for limiting SO_2 emissions from industrial boilers is being worked on by the EPA staff, with a projected proposal date of 1985.

Air Pollution Control Equipment

Particulate Emissions Control

Particulate emissions are controlled by using cyclones, wet scrubbers, electrostatic precipitators (ESPs), and fabric filters (baghouses). Cyclones are generally used to remove particles larger than $10 \mu\text{m}$ in diameter. These devices are occasionally used before wet scrubbers, ESPs, or baghouses to remove large particles. Wet scrubbers are generally used when both particulate and SO_2 emission reduction is desired.

Electrostatic precipitators have been used to reduce particulate emissions from boiler flue gas for over 50 years. ESPs have been designed to remove particles with at least 99.5% efficiency. ESPs used on boiler exhaust generally contain discharge electrodes and collection plates. The discharge electrodes are either long thin wires or wires attached together in rigid frames. Discharge electrodes create a strong electric field that ionizes flue gas as it passes through the ESP. This ionization charges the particles in the flue gas. Charged particles migrate to and are collected on oppositely charged collection plates. Cold-side ESPs are located behind the combustion air preheaters where the flue gas temperatures are approximately 400°F or less. Hot-side ESPs are located in front of air preheaters and are used to clean flue gas having temperatures greater than 572°F . One problem in using ESPs occurs when low-sulfur coal is burned in a boiler. The resulting fly ash has high resistivity and is difficult to collect. Hot-side ESPs were popular in the early 1970's for removing fly ash having high resistivity. However, many of these hot-side ESPs did not operate reliably, and vendors recently favor the use of cold-side ESPs and conditioning agents. Some of

these conditioning agents include sulfur trioxide, sulfuric acid, ammonia, sodium chloride, or soda ash. ESPs are covered in detail in APTI Course 412B *Electrostatic Precipitator Plan Review* (EPA 450/2-82-019).

Baghouses have been used to remove fly ash from flue gas at over 100 industrial and utility boiler installations in the U.S. Reports have shown that baghouses used on pulverized-coal-fired utility boilers are routinely capable of achieving collection efficiencies of 99.9%, stack opacities well below 5%, and outlet concentrations of 0.005 lb/10⁶ Btu (Carr and Smith, 1984). The collection efficiency for baghouses used on industrial coal-fired boilers has been equally high.

Baghouses are located downstream of air preheaters where the flue gas temperatures are typically 300 to 350°F. Baghouses contain long cylindrical bags made with fabric material. Bags hang vertically in the baghouse and filter dust on the outside or inside of the bag, depending on the baghouse design and purpose. The flue gas temperature in the baghouse must be carefully controlled and must be high enough to prevent water or acid from condensing in the baghouse. However, the temperature must be low enough (< 500°F) to keep the fabric material from deteriorating. Many baghouses use bags made of fiberglass that are coated with Teflon®, silicone, or graphite either singly or in combination. Other materials such as Teflon®, Ryton®, and acrylics have been used. Utility-boiler baghouses almost always contain fiberglass bags and use reverse air cleaning or shake and deflate cleaning. Industrial-boiler baghouses contain bags made with fiberglass, Teflon®, Nomex®, and Ryton®, and they clean dirty bags by reverse air, shaking, and pulse jet techniques. Baghouses are covered in detail in APTI Course 412B *Baghouse Plan Review* (EPA 450/2-82-005).

The required emission reduction efficiencies for meeting the various NSPS emission levels for particulate matter are given in Table 6-3. Baghouses and electrostatic precipitators are the most popular particulate emission control devices used to meet the NSPS (for particulate matter) on coal-fired boilers because they are generally the only devices that can consistently meet the 0.03 lb/10⁶ Btu emission limitations. Wet scrubbers are also used, but usually only when SO₂ emission control (FGD systems) is required. A summary of particulate matter control devices used to develop the proposed industrial boiler NSPS emission limits is given in Table 6-4.

**Table 6-3. Required efficiencies to achieve NSPS control levels
for particulate emissions.**

Boiler type and fuel	Fuel analysis % ash	Uncontrolled emissions ng/J (lb/10 ⁶ Btu)	Efficiency required at the given emission limit (%)		
			43 ng/J (0.1 lb/10 ⁶ Btu)	21.5 ng/J (0.05 lb/10 ⁶ Btu)	13 ng/J (0.03 lb/10 ⁶ Btu)
Pulverized coal ^a	5 to 11	1522 to 3350 (3.54 to 7.79)	97.18 to 98.72	98.59 to 99.34	99.15 to 99.62
Spreader stoker ^a	5 to 11	1165 to 2563 (2.71 to 5.96)	96.31 to 98.32	98.16 to 99.16	98.89 to 99.50
Chain grate stoker ^a	5 to 11	447 to 985 (1.04 to 2.29)	90.38 to 95.63	95.19 to 97.82	97.12 to 98.69
Underfeed stoker ^a	5 to 11	224 to 490 (0.52 to 1.14)	80.77 to 91.23	90.38 to 95.61	94.23 to 97.37
Residual oil ^b	3% sulfur 1% ash	96 (0.223)	55.16	77.58	86.55
Distillate oil ^b	0.5% sulfur	6.3 (0.0146)	—	—	—
Natural gas ^c	—	0.34 to 6.45 (0.0008 to 0.015)	—	—	—

^aReference AP-42 expresses emissions on a kg/MT (lb/ton) of fuel burned basis. A conversion factor of kJ/kg (12,000 Btu/lb) was used.

^bReference AP-42 expresses emissions on a kg/1000 ℓ (lb/1000 gal) of fuel burned basis. Conversion factors of 43,043 kJ/kg (18,500 Btu/lb) and 45,345 kJ/kg (19,500 Btu/lb) were used to convert factors to a heat input basis for residual and distillate oil respectively. Densities of 0.96 kg/ℓ (8.0 lb/gal) and 0.84 kg/ℓ (7.0 lb/gal) were also used.

^cReference AP-42 expresses emissions on a kg/10⁶ m³ (lb/10⁶ ft³) of fuel burned basis. A conversion factor of 50,707 kJ/kg (21,800 Btu/lb) and a density of 0.722 kg/m³ (0.0451 lb/ft³) were used.

**Table 6-4. Summary of particulate matter control devices to meet the
proposed NSPS emission limits.**

Fuel	Basis of proposed standard	Proposed emission limits ng/J (lb/million Btu) heat input		
		ng/J 21.5	lb/10 ⁶ Btu 0.05	Opacity 20%
Coal	Fabric filter/ESP	43	0.10	20%
Coal equipped with wet scrubbing FGD systems	Wet scrubber	43	0.10	20%
Wood	ESP/wet scrubber	43	0.10	20%
Solid waste	ESP	43	0.10	20%
Fuel mixtures containing above fuels	ESP/wet scrubber	43	0.10	20%

Sulfur Dioxide Control

Sulfur dioxides (SO_2) are emitted from coal-fired and oil-fired boilers burning fuels that contain sulfur. SO_2 emissions have been controlled by both wet and dry scrubbing. These are usually called flue gas desulfurization (FGD) processes. The two most popular wet scrubbing methods are lime and limestone scrubbing. Approximately 75% of all installed FGD systems use a lime or limestone slurry as the scrubbing liquor. Here SO_2 reacts with the lime or limestone slurry to form calcium sulfite and calcium sulfate sludge. The sludge must be disposed of in a pond or landfill. Other wet scrubbing systems include the Dual Alkali, Wellman-Lord, and Magnesium Oxide processes. Most wet scrubbing FGD systems are capable of reducing SO_2 emissions by 90%. Therefore, these wet FGD systems can usually be used to meet the SO_2 emission reduction requirements for the NSPS (Subpart Da).

In dry FGD scrubbing, an alkaline slurry is injected in a spray dryer with dry particle collection in a baghouse or electrostatic precipitator. Spray dryers are vessels where hot flue gases are contacted with a fine, wet, alkaline spray. SO_2 emissions are sorbed by the alkaline spray. The high temperature of the flue gas, 250 to 400 °F, evaporates the moisture from the alkaline spray, leaving a dry product. The dry product is collected in a baghouse or ESP. Dry scrubbing FGD systems can remove approximately 75 to 90% of the SO_2 emissions.

EPA-AEERL is currently working on a promising technology called Limestone Injection Multistage Burner (LIMB). In this process, limestone is injected with pulverized coal and burned in a multistage low NO_x burner. Current studies indicate an SO_2 reduction of 50% is possible with a limestone stoichiometric ratio of 2.0.

Sulfur oxides can also be reduced by coal cleaning or by using synthetic fuels. Coal can be cleaned by using physical and chemical coal cleaning methods. Mineral sulfur can be removed by physical methods in which coal is crushed, washed, and then separated by settling processes using cyclones, air classifiers, or magnetic separators. Organic-bound sulfur can be removed by chemical methods such as microwave desulfurization and hydrothermal desulfurization. The Air and Energy Engineering Research Laboratory (AEERL), formerly the Industrial Environmental Research Laboratory (IERL), of the EPA is currently involved in research of these technologies. Coal can also be gasified or liquefied into "cleaner" synthetic fuels. Commercial operation of synthetic fuel facilities is expected in the mid 1980's or early 1990's. Sulfur dioxide emission reduction is covered in detail in APTI Course 412C, *Wet Scrubber Plan Review* (EPA 450/2-82-020).

Nitrogen Oxide Control

Nitrogen oxides are emitted from gas-, oil-, and coal-fired boilers. These emissions can be reduced by two control methods: *combustion modifications* and *flue gas treatment*. Combustion modifications are changes made in the operation and design of the furnace. Some of the more widely used combustion modification techniques include the use of low excess air, staged combustion, flue gas recirculation, and low- NO_x burners. These combustion modifications are done to alter the combustion conditions in the furnace. This can be accomplished by:

- reducing the peak flame temperature,
- reducing the residence time the combustion products remain in the chamber,
- diverting approximately 15% of the fuel further downstream in the combustion chamber to achieve "reburning,"
- changing the mixing rate of the fuel and air, or
- increasing the temperature and residence time in precombustor chamber.

NO_x emissions can be reduced from 10 to 40% depending on the fuel burned and the combustion conditions in the furnace. Combustion modification techniques can usually be used to meet all of the NSPS NO_x emission limits (Subparts D, Da, and Db).

Nitrogen oxide emissions can also be reduced by treating the flue gas after it leaves the combustion zone. This technique can be used when there is a need to reduce NO_x emissions to very low levels, such as the NO_x emission reduction from utility boilers now required by the South Coast Air Quality Management District in California. However, flue gas treatment is not required to meet any of the NSPS standards for industrial or utility boilers.

Flue gas treatment methods include the Exxon Thermal De-NO_x, Selective Catalytic Reduction (SCR), and the Shell UOP processes. These processes have been used in Japan to reduce NO_x emissions from utility boilers. Pilot projects are currently being tested in the United States at a number of utilities. Full scale units are expected to be installed in the next few years. The Exxon process has reduced NO_x emissions by 60%, and the SCR and Shell UOP processes have reduced NO_x emissions by 90%. Nitrogen oxide emission reduction techniques are covered in detail in APTI Course 415, *Control of Gaseous Emissions* (EPA 450/2-81-005).

Summary

Industrial and utility boilers can emit significant amounts of air pollutants into the atmosphere. Air pollution regulations have been developed to limit the amount of pollution that can be emitted. Regulations such as the NSPS have been one tool used to help improve and maintain air quality. Major efforts by industry to develop and install air pollution control devices to meet air pollution regulations will help our society in its continual struggle for protecting the quality of air we breathe.

Review Exercise

1. True or False? The amount of particulate emissions from coal-fired boilers depend on the way the coal is burned in the furnace.	
2. In a boiler, _____ is emitted when the _____ in the fuel is oxidized; while _____ is emitted when the _____ in the fuel is oxidized and the _____ in the air is burned.	1. True
3. The 1971 NSPS was promulgated to regulate emissions from <ul style="list-style-type: none"> a. electric utility boilers greater than 73 MW. b. industrial boilers greater than 73 MW. c. electric utility and industrial boilers greater than 73 MW. d. electric utility and industrial boilers less than 73 MW. 	2. sulfur dioxide, sulfur, nitrogen oxide, nitrogen, nitrogen
4. The 1978 NSPS was promulgated to regulate emissions from <ul style="list-style-type: none"> a. electric utility and industrial boilers greater than 73 MW. b. industrial boilers greater than 29 MW. c. electric utility boilers greater than 73 MW. d. electric utility boilers greater than 29 MW. 	3. c. electric utility and industrial boilers greater than 73 MW.
5. The 1978 NSPS for electric utility boilers requires <ul style="list-style-type: none"> a. 90% SO₂ emission reduction and SO₂ emissions less than 1.2 lb/10⁶ Btu. b. 70% SO₂ emission reduction and SO₂ emissions less 0.6 lb/10⁶ Btu. c. a sliding scale of from 70% to 90% as long as SO₂ emissions after control are less than 0.6 lb/10⁶ Btu. d. all of the above e. a. and b. only 	4. c. electric utility boilers greater than 73 MW.
6. Boilers burning low-sulfur coal produce fly ash having high resistivity which is difficult to collect using a <ul style="list-style-type: none"> a. baghouse. b. electrostatic precipitator. c. wet scrubber. d. dry scrubber. 	5. d. all of the above
	6. b. electrostatic precipitator.

7. Because of high temperature flue gas from utility boilers, baghouses used on them contain a. coated wool bags. b. uncoated cotton bags. c. coated fiberglass bags. d. all of the above	
8. Most FGD installations use _____ to reduce SO ₂ emissions. a. dual alkali and magnesium oxide scrubbing b. lime and limestone scrubbing c. the Wellman-Lord process d. dry scrubbing	7. c. coated fiberglass bags.
9. Combustion modification techniques are used to reduce nitrogen oxide emissions from boilers. These include a. low excess air. b. staged combustion. c. flue gas recirculation. d. low NO _x burners. e. all of the above f. none of the above	8. b. lime and limestone scrubbing
	9. e. all of the above

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Appendix A

(The following pages are excerpts from AP-42
which relate to combustion sources)

**COMPILATION
OF
AIR POLLUTANT EMISSION FACTORS
Third Edition
(Including Supplements 1-7)**

**U.S. Environmental Protection Agency
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711**

August 1977

This report is published by the Environmental Protection Agency to report information of general interest in the field of air pollution. Copies are available free of charge to Federal employees, current contractors and grantees, and nonprofit organizations—as supplies permit—from the Library Services Office, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. This document is also available to the public for sale through the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C.

Publication No. AP-42

1. EXTERNAL COMBUSTION SOURCES

External combustion sources include steam-electric generating plants, industrial boilers, commercial and institutional boilers, and commercial and domestic combustion units. Coal, fuel oil, and natural gas are the major fossil fuels used by these sources. Other fuels used in relatively small quantities are liquefied petroleum gas, wood, coke, refinery gas, blast furnace gas, and other waste- or by-product fuels. Coal, oil, and natural gas currently supply about 95 percent of the total thermal energy consumed in the United States. In 1970 over 500 million tons (454×10^6 MT) of coal, 623 million barrels (99×10^9 liters) of distillate fuel oil, 715 million barrels (114×10^9 liters) of residual fuel oil, and 22 trillion cubic feet (623×10^{12} liters) of natural gas were consumed in the United States.¹

Power generation, process heating, and space heating are some of the largest fuel-combustion sources of sulfur oxides, nitrogen oxides, and particulate emissions. The following sections present emission factor data for the major fossil fuels — coal, fuel oil, and natural gas — as well as for liquefied petroleum gas and wood waste combustion in boilers.

REFERENCE

1. Ackerson, D.H. Nationwide Inventory of Air Pollutant Emissions. Unpublished report. Office of Air and Water Programs, Environmental Protection Agency, Research Triangle Park, N.C. May 1971.

1.1 BITUMINOUS COAL COMBUSTION

*Revised by Robert Rosensteel
and Thomas Lahre*

1.1.1 General

Coal, the most abundant fossil fuel in the United States, is burned in a wide variety of furnaces to produce heat and steam. Coal-fired furnaces range in size from small handfired units with capacities of 10 to 20 pounds (4.5 to 9 kilograms) of coal per hour to large pulverized-coal-fired units, which may burn 300 to 400 tons (275 to 360 MT) of coal per hour.

Although predominantly carbon, coal contains many compounds in varying amounts. The exact nature and quantity of these compounds are determined by the location of the mine producing the coal and will usually affect the final use of the coal.

1.1.2 Emissions and Controls

1.1.2.1 Particulates¹ - Particulates emitted from coal combustion consist primarily of carbon, silica, alumina, and iron oxide in the fly-ash. The quantity of atmospheric particulate emissions is dependent upon the type of combustion unit in which the coal is burned, the ash content of the coal, and the type of control equipment used.

Table 1.1-1 gives the range of collection efficiencies for common types of fly-ash control equipment. Particulate emission factors expressed as pounds of particulate per ton of coal burned are presented in Table 1.1-2.

1.1.2.2 Sulfur Oxides^{1,11} - Factors for uncontrolled sulfur oxides emission are shown in Table 1-2 along with factors for other gases emitted. The emission factor for sulfur oxides indicates a conversion of 95 percent of the available sulfur to sulfur oxide. The balance of the sulfur is emitted in the fly-ash or combines with the slag or ash in the furnace and is removed with them.¹ Increased attention has been given to the control of sulfur oxide emissions from the combustion of coal. The use of low-sulfur coal has been recommended in many areas; where low-sulfur coal is not available, other methods in which the focus is on the removal of sulfur oxide from the flue gas before it enters the atmosphere must be given consideration.

A number of flue-gas desulfurization processes have been evaluated; effective methods are undergoing full-scale operation. Processes included in this category are: limestone-dolomite injection, limestone wet scrubbing, catalytic oxidation, magnesium oxide scrubbing, and the Wellman-Lord process. Detailed discussion of various flue-gas desulfurization processes may be found in the literature.^{12,13}

1.1.2.3. Nitrogen Oxides^{1,5} - Emissions of oxides of nitrogen result not only from the high temperature reaction of atmospheric nitrogen and oxygen in the combustion zone, but also from the partial combustion of nitrogenous compounds contained in the fuel. The important factors that affect NO_x production are: flame and furnace temperature, residence time of combustion gases at the flame temperature, rate of cooling of the gases, and amount of excess air present in the flame. Discussions of the mechanisms involved are contained in the indicated references.

1.1.2.4 Other Gases - The efficiency of combustion primarily determines the carbon monoxide and hydrocarbon content of the gases emitted from bituminous coal combustion. Successful combustion that results in a low level of carbon monoxide and organic emissions requires a high degree of turbulence, a high temperature, and sufficient time for the combustion reaction to take place. Thus, careful control of excess air rates, the use of high combustion temperature, and provision for intimate fuel-air contact will minimize these emissions.

Factors for these gaseous emissions are also presented in Table 1.1-2. The size range in Btu per hour for the various types of furnaces as shown in Table 1.1-2 is only provided as a guide in selecting the proper factor and is not meant to distinguish clearly between furnace applications.

TABLE 1.1-1. RANGE OF COLLECTION EFFICIENCIES FOR COMMON TYPES OF FLY-ASH CONTROL EQUIPMENT^a

Type of furnace	Range of collection efficiencies, %			
	Electrostatic precipitator	High-efficiency cyclone	Low-resistance cyclone	Settling chamber expanded chimney bases
Cyclone furnaces	65 to 99.5 ^b	30 to 40	20 to 30	10 ^b
Pulverized unit	80 to 99.5 ^b	65 to 75	40 to 60	20 ^b
Spreader stoker	99.5 ^b	85 to 90	70 to 80	20 to 30
Other stokers	99.5 ^b	90 to 95	75 to 85	25 to 50

^aReferences 1 and 2.

^bThe maximum efficiency to be expected for this collection device applied to this type source.

Table 1.1-2. EMISSION FACTORS FOR BITUMINOUS COAL COMBUSTION WITHOUT CONTROL EQUIPMENT
EMISSION FACTOR RATING: A

Furnace size, 10 ⁶ Btu/hr heat input ^a	Particulates ^b		Sulfur oxides ^c		Carbon monoxide		Hydro- carbons ^d		Nitrogen oxides		Aldehydes	
	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned	lb/ton coal burned	kg/MT coal burned
Greater than 100^e (Utility and large industrial boilers)												
Pulverized												
General	16A	8A	38S	19S	1	0.5	0.3	0.15	18	9	0.005	0.0025
Wet bottom	13A ^f	6.5A	38S	19S	1	0.5	0.3	0.15	30	15	0.005	0.0025
Dry bottom	17A	8.5A	38S	19S	1	0.5	0.3	0.15	18	9	0.005	0.0025
Cyclone	2A	1A	38S	19S	1	0.5	0.3	0.15	55	27.5	0.005	0.0025
10 to 100^e (large commercial and general industrial boilers)												
Spreader stoker ^h	13A ^f	6.5A	38S	19S	2	1	1	0.5	15	7.5	0.005	0.0025
Less than 10ⁱ (commercial and domestic furnaces)												
Underfeed stoker	2A	1A	38S	19S	10	5	3	1.5	6	3	0.005	0.0025
Hand-fired units	20	10	38S	19S	90	45	20	10	3	1.5	0.005	0.0025

^a 1 Btu/hr = 0.252 kcal/hr.

^b The letter A on all units other than hand-fired equipment indicates that the weight percentage of ash in the coal should be multiplied by the value given.
 Example: If the factor is 16 and the ash content is 10 percent, the particulate emissions before the control equipment would be 10 times 16, or 160 pounds of particulate per ton of coal (10 times 8, or 80 kg of particulates per MT of coal).

^c S equals the sulfur content (see footnote b above).

^d Expressed as methane.

^e References 1 and 3 through 7.

^f Without fly-ash reinjection.

^g References 1, 4, and 7 through 9.

^h For all other stokers use 5A for particulate emission factor.

ⁱ Without fly-ash reinjection. With fly-ash reinjection use 20 A. This value is not an emission factor but represents loading reaching the control equipment.¹

¹ References 7, 9, and 10.

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1.2 ANTHRACITE COAL COMBUSTION

revised by Tom Lohre

1.2.1 General^{1,2}

Anthracite is a high-rank coal having a high fixed-carbon content and low volatile-matter content relative to bituminous coal and lignite. It is also characterized by higher ignition and ash fusion temperatures. Because of its low volatile-matter content and non-clinkering characteristics, anthracite is most commonly fired in medium-sized traveling-grate stokers and small hand-fired units. Some anthracite (occasionally along with petroleum coke) is fired in pulverized-coal-fired boilers. None is fired in spreader stokers. Because of its low sulfur content (typically less than 0.8 percent, by weight) and minimal smoking tendencies, anthracite is considered a desirable fuel where readily available.

In the United States, all anthracite is mined in Northeastern Pennsylvania and consumed primarily in Pennsylvania and several surrounding states. The largest use of anthracite is for space heating; lesser amounts are employed for steam-electric production, coke manufacturing, sintering and pelletizing, and other industrial uses. Anthracite combustion currently represents only a small fraction of the total quantity of coal combusted in the United States.

1.2.2 Emissions and Controls²⁻⁹

Particulate emissions from anthracite combustion are a function of furnace-firing configuration, firing practices (boiler load, quantity and location of underfire air, sootblowing, flyash reinjection, etc.), as well as of the ash content of the coal. Pulverized-coal-fired boilers emit the highest quantity of particulate per unit of fuel because they fire the anthracite in suspension, which results in a high percentage of ash carryover into the exhaust gases. Traveling-grate stokers and hand-fired units, on the other hand, produce much less particulate per unit of fuel fired. This is because combustion takes place in a quiescent fuel bed and does not result in significant ash carryover into the exhaust gases. In general, particulate emissions from traveling-grate stokers will increase during sootblowing, flyash reinjection, and with higher underfeed air rates through the fuel bed. Higher underfeed air rates, in turn, result from higher grate loadings and the use of forced-draft fans rather than natural draft to supply combustion air. Smoking is rarely a problem because of anthracite's low volatile-matter content.

Limited data are available on the emission of gaseous pollutants from anthracite combustion. It is assumed, based on data derived from bituminous coal combustion, that a large fraction of the fuel sulfur is emitted as sulfur oxides. Moreover, because combustion equipment, excess air rates, combustion temperatures, etc., are similar between anthracite and bituminous coal combustion, nitrogen oxide and carbon monoxide emissions are assumed to be similar, as well. On the other hand, hydrocarbon emissions are expected to be considerably lower because the volatile-matter content of anthracite is significantly less than that of bituminous coal.

Air pollution control of emissions from anthracite combustion has mainly been limited to particulate matter. The most efficient particulate controls—fabric filters, scrubbers, and electrostatic precipitators—have been installed on large pulverized-anthracite-fired boilers. Fabric filters and venturi scrubbers can effect collection efficiencies exceeding 99 percent. Electrostatic precipitators, on the other hand, are typically only 90 to 97 percent efficient due to the characteristic high resistivity of the low-sulfur anthracite flyash. Higher efficiencies can reportedly be achieved using larger precipitators and flue gas conditioning. Mechanical collectors are frequently employed upstream from these devices for large-particle removal.

Traveling-grate stokers are often uncontrolled. Indeed, particulate control has often been considered unnecessary because of anthracite's low smoking tendencies and due to the fact that a significant fraction of the large-sized flyash from stokers is readily collected in flyash hoppers as well as in the breeching and base of the stack. Cyclone collectors have been employed on traveling-grate stokers;

limited information suggests these devices may be up to 75 percent efficient on particulate. Flyash reinjection, frequently employed in traveling-grate stokers to enhance fuel-use efficiency, tends to increase particulate emissions per unit of fuel combusted.

Emission factors for anthracite combustion are presented in Table 1.2-1.

Table 1.2-1. EMISSION FACTORS FOR ANTHRACITE COMBUSTION, BEFORE CONTROLS
EMISSION FACTOR RATING: B

Type of furnace	Emissions ^a									
	Particulate		Sulfur oxides ^b		Hydrocarbons ^c		Carbon monoxide ^d		Nitrogen oxides ^e	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Pulverized coal	17A ^f	8.6A ^f	38S	19S	Neg	Neg	1	0.5	18	9
Traveling grate	1A ^g	0.5A ^g	38S	19S	Neg	Neg	1	0.5	10	5
Hand-fired	10 ^h	5 ^h	38S	19S	2.5	1.25	90	45	3	1.5

^aAll emission factors are per unit of anthracite fired.

^bThese factors are based on the assumption that, as with bituminous coal combustion, most of the fuel sulfur is emitted as sulfur oxides. Limited data in Reference 6 verify this assumption for pulverized-anthracite-fired boilers. Generally most of these emissions are sulfur dioxide; however, approximately 1 to 3 percent are sulfur trioxide.

^cHydrocarbon emissions from anthracite combustion are assumed to be lower than from bituminous coal combustion because of anthracite's much lower volatile-matter content. No emissions data are available to verify this assumption.

^dThe carbon monoxide factors for pulverized-anthracite-fired boilers and hand-fired units are from Table 1.1-2 and are based on the similarity between anthracite and bituminous coal combustion. The pulverized-coal-fired boilers factor is substantiated by additional data in Reference 10. The factor for traveling-grate stokers is based on limited information in Reference 8. Carbon monoxide emissions may increase by several orders of magnitude if a boiler is not properly operated or well maintained.

^eThe nitrogen oxide factors for pulverized-anthracite-fired boilers and hand-fired units are assumed to be similar to those for bituminous coal combustion given in Table 1.1-2. The factors for traveling-grate stokers are based on Reference 8.

^fThese factors are based on the similarity between anthracite and bituminous coal combustion and on limited data in Reference 6. Note that all pulverized-anthracite-fired boilers operate in the dry tap or dry bottom mode due to anthracite's characteristically high ash-fusion temperature. The letter A on units other than hand-fired equipment indicates that the weight percentage of ash in the coal should be multiplied by the value given.

^gBased on information in References 2, 4, 8, and 9. These factors account for limited fallout that may occur in fallout chambers and stack breaching. Emission factors for individual boilers may vary from 0.5A lb/ton (0.25A kg/MT) to 3A lb/ton (1.5A kg/MT), and as high as 5A lb/ton (2.5A kg/MT) during soot blowing.

^hBased on limited information in Reference 2.

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1.3.1 General^{1,2}

Fuel oils are broadly classified into two major types: distillate and residual. Distillate oils (fuel oil grades 1 and 2) are used mainly in domestic and small commercial applications in which easy fuel burning is required. Distillates are more volatile and less viscous than residual oils as well as cleaner, having negligible ash and nitrogen contents and usually containing less than 0.3 percent sulfur (by weight). Residual oils (fuel oil grades 4, 5, and 6), on the other hand, are used mainly in utility, industrial, and large commercial applications in which sophisticated combustion equipment can be utilized. (Grade 4 oil is sometimes classified as a distillate; grade 6 is sometimes referred to as Bunker C.) Being more viscous and less volatile than distillate oils, the heavier residual oils (grades 5 and 6) must be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue left over after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Properties of typical fuel oils are given in Appendix A.

1.3.2 Emissions

Emissions from fuel oil combustion are dependent on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Table 1.3-1 presents emission factors for fuel oil combustion in units without control equipment. Note that the emission factors for industrial and commercial boilers are divided into distillate and residual oil categories because the combustion of each produces significantly different emissions of particulates, SO_x , and NO_x . The reader is urged to consult the references cited for a detailed discussion of all of the parameters that affect emissions from oil combustion.

1.3.2.1 Particulates^{3-6, 12, 13} – Particulate emissions are most dependent on the grade of fuel fired. The lighter distillate oils result in significantly lower particulate formation than do the heavier residual oils. Among residual oils, grades 4 and 5 usually result in less particulate than does the heavier grade 6.

In boilers firing grade 6, particulate emissions can be described, on the average, as a function of the sulfur content of the oil. As shown in Table 1.3-1 (footnote c), particulate emissions can be reduced considerably when low-sulfur grade 6 oil is fired. This is because low-sulfur grade 6, whether refined from naturally occurring low-sulfur crude oil or desulfurized by one of several processes currently in practice, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur content – all of which result in better atomization and cleaner combustion.

Boiler load can also affect particulate emissions in units firing grade 6 oil. At low load conditions, particulate emissions may be lowered by 30 to 40 percent from utility boilers and by as much as 60 percent from small industrial and commercial units. No significant particulate reductions have been noted at low loads from boilers firing any of the lighter grades, however. At too low a load condition, proper combustion conditions cannot be maintained and particulate emissions may increase drastically. It should be noted, in this regard, that any condition that prevents proper boiler operation can result in excessive particulate formation.

1.3.2.2 Sulfur Oxides (SO_x)¹⁻⁵ – Total sulfur oxide emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On the average, more than 95 percent of the fuel sulfur is converted to SO_2 , with about 1 to 3 percent further oxidized to SO_3 . Sulfur trioxide readily reacts with water vapor (both in the air and in the flue gases) to form a sulfuric acid mist.

Table 1.3-1. EMISSION FACTORS FOR FUEL OIL COMBUSTION
EMISSION FACTOR RATING: A

Pollutant	Type of boiler ^a							
	Power plant		Industrial and commercial				Domestic	
	Residual oil		Residual oil		Distillate oil		Distillate oil	
	lb/10 ³ gal	kg/10 ³ liter	lb/10 ³ gal	kg/10 ³ liter	lb/10 ³ gal	kg/10 ³ liter	lb/10 ³ gal	kg/10 ³ liter
Particulate ^b	c	c	c	c	2	0.26	2.5	0.31
Sulfur dioxide ^d	167S	19S	167S	19S	142S	17S	142S	17S
Sulfur trioxide ^d	2S	0.26S	2S	0.26S	2S	0.26S	2S	0.26S
Carbon monoxide ^e	5	0.63	5	0.63	5	0.63	5	0.63
Hydrocarbons (total, as CH ₄) ^f	1	0.12	1	0.12	1	0.12	1	0.12
Nitrogen oxides (total, as NO ₂) ^g	105(50) ^{h,i}	12.6(6.25) ^{h,i}	60 ^j	7.5 ^j	22	2.8	18	2.3

^aBoilers can be classified, roughly, according to their gross (higher) heat input rate, as shown below.

Power plant (utility) boilers: $>250 \times 10^6$ Btu/hr
 $(>63 \times 10^6$ kg-cal/hr)
 Industrial boilers: $>15 \times 10^6$, but $<250 \times 10^6$ Btu/hr
 $(>3.7 \times 10^6$, but $<63 \times 10^6$ kg-cal/hr)
 Commercial boilers: $>0.5 \times 10^6$, but $<15 \times 10^6$ Btu/hr
 $(>0.13 \times 10^6$, but $<3.7 \times 10^6$ kg-cal/hr)
 Domestic (residential) boilers: $<0.5 \times 10^6$ Btu/hr
 $(<0.13 \times 10^6$ kg-cal/hr)

^bBased on References 3 through 6. Particulate is defined in this section as that material collected by EPA Method 5 (front half catch)⁷.

^cParticulate emission factors for residual oil combustion are best described, on the average, as a function of fuel oil grade and sulfur content, as shown below.

Grade 8 oil: lb/10³ gal = 10 (S) + 3
 [kg/10³ liter = 1.25 (S) + 0.38]
 Where: S is the percentage, by weight, of sulfur in the oil
 Grade 6 oil: 10 lb/10³ gal (1.25 kg/10³ liter)
 Grade 4 oil: 7 lb/10³ gal (0.88 kg/10³ liter)

^dBased on References 1 through 5. S is the percentage, by weight, of sulfur in the oil.

^eBased on References 3 through 5 and 8 through 10. Carbon monoxide emissions may increase by a factor of 10 to 100 if a unit is improperly operated or not well maintained.

^fBased on References 1, 3 through 5, and 10. Hydrocarbon emissions are generally negligible unless unit is improperly operated or not well maintained, in which case emissions may increase by several orders of magnitude.

^gBased on References 1 through 5 and 8 through 11.

^hUse 50 lb/10³ gal (6.25 kg/10³ liter) for tangentially fired boilers and 105 lb/10³ gal (12.6 kg/10³ liter) for all others, at full load, and normal (>15 percent) excess air. At reduced loads, NO_x emissions are reduced by 0.5 to 1 percent, on the average, for every percentage reduction in boiler load.

ⁱSeveral combustion modifications can be employed for NO_x reduction: (1) limited excess air firing can reduce NO_x emissions by 5 to 30 percent, (2) staged combustion can reduce NO_x emissions by 20 to 45 percent, and (3) flue gas recirculation can reduce NO_x emissions by 10 to 45 percent. Combinations of the modifications have been employed to reduce NO_x emissions by as much as 60 percent in certain boilers. See section 1.4 for a discussion of these NO_x-reducing techniques.

^jNitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly dependent on the fuel nitrogen content and can be estimated more accurately by the following empirical relationship:

$$\text{lb NO}_2/10^3 \text{ gal} = 22 + 400 (N)^2$$

$$[\text{kg NO}_2/10^3 \text{ liters} = 2.75 + 50 (N)^2]$$

Where: N is the percentage, by weight, of nitrogen in the oil. Note: For residual oils having high ($>0.5\%$, by weight) nitrogen contents, one should use 120 lb NO₂/10³ gal (16 kg NO₂/10³ liter) as an emission factor.

1.3.2.3 Nitrogen Oxides (NO_x)^{1-6, 8-11, 14} – Two mechanisms form nitrogen oxides: oxidation of fuel-bound nitrogen and thermal fixation of the nitrogen present in combustion air. Fuel NO_x are primarily a function of the nitrogen content of the fuel and the available oxygen (on the average, about 45 percent of the fuel nitrogen is converted to NO_x , but this may vary from 20 to 70 percent). Thermal NO_x , on the other hand, are largely a function of peak flame temperature and available oxygen – factors which are dependent on boiler size, firing configuration, and operating practices.

Fuel nitrogen conversion is the more important NO_x -forming mechanism in boilers firing residual oil. Except in certain large units having unusually high peak flame temperatures, or in units firing a low-nitrogen residual oil, fuel NO_x will generally account for over 50 percent of the total NO_x generated. Thermal fixation, on the other hand, is the predominant NO_x -forming mechanism in units firing distillate oils, primarily because of the negligible nitrogen content in these lighter oils. Because distillate-oil-fired boilers usually have low heat release rates, however, the quantity of thermal NO_x formed in them is less than in larger units.

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. Nitrogen oxides emissions from tangentially (corner) fired boilers are, on the average, only half those of horizontally opposed units. Also important are the firing practices employed during boiler operation. The use of limited excess air firing, flue gas recirculation, staged combustion, or some combination thereof, may result in NO_x reductions ranging from 5 to 60 percent. (See section 1.4 for a discussion of these techniques.) Load reduction can likewise decrease NO_x production. Nitrogen oxides emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. It should be noted that most of these variables, with the exception of excess air, are applicable only in large oil-fired boilers. Limited excess air firing is possible in many small boilers, but the resulting NO_x reductions are not nearly as significant.

1.3.2.4 Other Pollutants^{1, 3-5, 8-10, 14} – As a rule, only minor amounts of hydrocarbons and carbon monoxide will be produced during fuel oil combustion. If a unit is operated improperly or not maintained, however, the resulting concentrations of these pollutants may increase by several orders of magnitude. This is most likely to be the case with small, often unattended units.

1.3.3 Controls

Various control devices and/or techniques may be employed on oil-fired boilers depending on the type of boiler and the pollutant being controlled. All such controls may be classified into three categories: boiler modification, fuel substitution, and flue gas cleaning.

1.3.3.1 Boiler Modification^{1-4, 8, 9, 13, 14} – Boiler modification includes any physical change in the boiler apparatus itself or in the operation thereof. Maintenance of the burner system, for example, is important to assure proper atomization and subsequent minimization of any unburned combustibles. Periodic tuning is important in small units to maximize operating efficiency and minimize pollutant emissions, particularly smoke and CO. Combustion modifications such as limited excess air firing, flue gas recirculation, staged combustion, and reduced load operation all result in lowered NO_x emissions in large facilities. (See Table 1.3-1 for specific reductions possible through these combustion modifications.)

1.3.3.2 Fuel Substitution^{3-5, 12} – Fuel substitution, that is, the firing of “cleaner” fuel oils, can substantially reduce emissions of a number of pollutants. Lower sulfur oils, for instance, will reduce SO_x emissions in all boilers regardless of size or type of unit or grade of oil fired. Particulates will generally be reduced when a better grade of oil is fired. Nitrogen oxide emissions will be reduced by switching to either a distillate oil or a residual oil containing less nitrogen. The practice of fuel substitution, however, may be limited by the ability of a given operation to fire a better grade of oil as well as the cost and availability thereof.

1.3.3.3 Flue Gas Cleaning^{6, 15-21} - Flue gas cleaning equipment is generally only employed on large oil-fired boilers. Mechanical collectors, a prevalent type of control device, are primarily useful in controlling particulates generated during soot blowing, during upset conditions, or when a very dirty, heavy oil is fired. During these situations, high efficiency cyclonic collectors can effect up to 85 percent control of particulate. Under normal firing conditions, however, or when a clean oil is combusted, cyclonic collectors will not be nearly as effective.

Electrostatic precipitators are commonly found in power plants that at one time fired coal. Precipitators that were designed for coal flyash provide only 40 to 60 percent control of oil-fired particulate. Collection efficiencies of up to 90 percent, however, have been reported for new or rebuilt devices that were specifically designed for oil-firing units.

Scrubbing systems have been installed on oil-fired boilers, especially of late, to control both sulfur oxides and particulate. These systems can achieve SO₂ removal efficiencies of up to 90 to 95 percent and provide particulate control efficiencies on the order of 50 to 60 percent. The reader should consult References 20 and 21 for details on the numerous types of flue gas desulfurization systems currently available or under development.

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1.4.1 General 1.2

Natural gas has become one of the major fuels used throughout the country. It is used mainly for power generation, for industrial process steam and heat production, and for domestic and commercial space heating. The primary component of natural gas is methane, although varying amounts of ethane and smaller amounts of nitrogen, helium, and carbon dioxide are also present. The average gross heating value of natural gas is approximately 1050 Btu/stdft³ (9350 kcal/Nm³), varying generally between 1000 and 1100 Btu/stdft³ (8900 to 9800 kcal/Nm³).

Because natural gas in its original state is a gaseous, homogenous fluid, its combustion is simple and can be precisely controlled. Common excess air rates range from 10 to 15 percent; however, some large units operate at excess air rates as low as 5 percent to maximize efficiency and minimize nitrogen oxide (NO_x) emissions.

1.4.2 Emissions and Controls 3-16

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

Nitrogen oxides are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions are a function of the temperature in the combustion chamber and the rate of cooling of the combustion products. Emission levels generally vary considerably with the type and size of unit and are also a function of loading.

In some large boilers, several operating modifications have been employed for NO_x control. Staged combustion, for example, including off-stoichiometric firing and/or two-stage combustion, can reduce NO_x emissions by 30 to 70 percent. In off-stoichiometric firing, also called "biased firing," some burners are operated fuel-rich, some fuel-lean, while others may supply air only. In two-staged combustion, the burners are operated fuel-rich (by introducing only 80 to 95 percent stoichiometric air) with combustion being completed by air injected above the flame zone through second-stage "NO-ports." In staged combustion, NO_x emissions are reduced because the bulk of combustion occurs under fuel-rich, reducing conditions.

Other NO_x-reducing modifications include low excess air firing and flue gas recirculation. In low excess air firing, excess air levels are kept as low as possible without producing unacceptable levels of unburned combustibles (carbon monoxide, hydrocarbons, and smoke) and/or other operational problems. This technique can reduce NO_x emissions by 10 to 30 percent primarily because of the lack of availability of oxygen during combustion. Flue gas recirculation into the primary combustion zone, because the flue gas is relatively cool and oxygen deficient, can also lower NO_x emissions by 20 to 60 percent depending on the amount of gas recirculated. At present only a few systems have this capability, however.

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

Emission factors for natural gas combustion are presented in Table 1.4-1. Flue gas cleaning equipment has not been utilized to control emissions from natural gas combustion equipment.

Table 1.4-1. EMISSION FACTORS FOR NATURAL-GAS COMBUSTION
EMISSION FACTOR RATING: A

Pollutant	Type of unit					
	Power plant		Industrial process boiler		Domestic and commercial heating	
	lb/10 ⁶ ft ³	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	kg/10 ⁶ m ³	lb/10 ⁶ ft ³	kg/10 ⁶ m ³
Particulates ^a	5-15	80-240	5-15	80-240	5-15	80-240
Sulfur oxides (SO ₂) ^b	0.6	9.6	0.6	9.6	0.6	9.6
Carbon monoxide ^c	17	272	17	272	20	320
Hydrocarbons (as CH ₄) ^d	1	16	3	48	8	128
Nitrogen oxides (NO ₂) ^e	700 ^{f-h}	11,200 ^{f-h}	(120-230) ⁱ	(1920-3680) ⁱ	(80-120) ⁱ	(1280-1920) ⁱ

^aReferences 4,7,8,12.

^bReference 4 (based on an average sulfur content of natural gas of 2000 gr/10⁶ stdft³ (4600 g/10⁶ Nm³).

^cReferences 5, 8-12.

^dReferences 8, 9, 12.

^eReferences 3-9, 12-16.

^f Use 300 lb/10⁶ stdft³ (4800 kg/10⁶ Nm³) for tangentially fired units.

^gAt reduced loads, multiply this factor by the load reduction coefficient given in Figure 1.4-1.

^hSee text for potential NO_x reductions due to combustion modifications. Note that the NO_x reduction from these modifications will also occur at reduced load conditions.

ⁱ This represents a typical range for many industrial boilers. For large industrial units (> 100 MMBtu/hr) use the NO_x factors presented for power plants.

^j Use 80 (1280) for domestic heating units and 120 (1920) for commercial units.

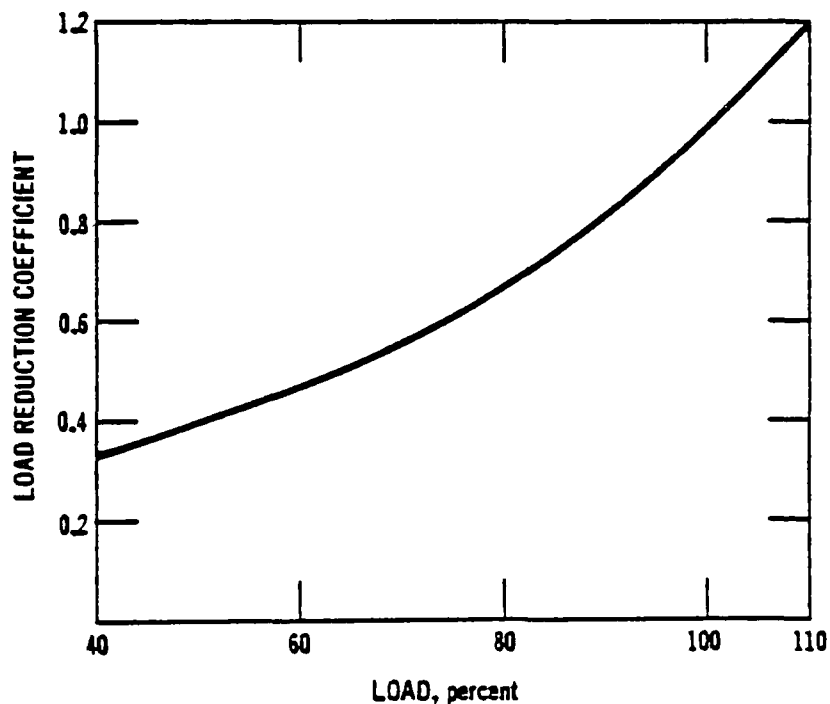


Figure 1.4-1. Load reduction coefficient as function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

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1.5 LIQUEFIED PETROLEUM GAS COMBUSTION

Revised by Thomas Lahre

1.5.1 General¹

Liquefied petroleum gas, commonly referred to as LPG, consists mainly of butane, propane, or a mixture of the two, and of trace amounts of propylene and butylene. This gas, obtained from oil or gas wells as a by-product of gasoline refining, is sold as a liquid in metal cylinders under pressure and, therefore, is often called bottled gas. LPG is graded according to maximum vapor pressure with Grade A being predominantly butane, Grade F being predominantly propane, and Grades B through E consisting of varying mixtures of butane and propane. The heating value of LPG ranges from 97,400 Btu/gallon (6,480 kcal/liter) for Grade A to 90,500 Btu/gallon (6,030 kcal/liter) for Grade F. The largest market for LPG is the domestic-commercial market, followed by the chemical industry and the internal combustion engine.

1.5.2 Emissions¹

LPG is considered a "clean" fuel because it does not produce visible emissions. Gaseous pollutants such as carbon monoxide, hydrocarbons, and nitrogen oxides do occur, however. The most significant factors affecting these emissions are the burner design, adjustment, and venting.² Improper design, blocking and clogging of the flue vent, and lack of combustion air result in improper combustion that causes the emission of aldehydes, carbon monoxide, hydrocarbons, and other organics. Nitrogen oxide emissions are a function of a number of variables including temperature, excess air, and residence time in the combustion zone. The amount of sulfur dioxide emitted is directly proportional to the amount of sulfur in the fuel. Emission factors for LPG combustion are presented in Table 1.5-1.

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Table 1.5-1. EMISSION FACTORS FOR LPG COMBUSTION^a
EMISSION FACTOR RATING: C

Pollutant	Industrial process furnaces				Domestic and commercial furnaces			
	Butane		Propane		Butane		Propane	
	lb/10 ³ gal	kg/10 ³ liters	lb/10 ³ gal	kg/10 ³ liters	lb/10 ³ gal	kg/10 ³ liters	lb/10 ³ gal	kg/10 ³ liters
Particulates	1.8	0.22	1.7	0.20	1.9	0.23	1.8	0.22
Sulfur oxides ^b	0.09S	0.01S	0.09S	0.01S	0.09S	0.01S	0.09S	0.01S
Carbon monoxide	1.6	0.19	1.5	0.18	2.0	0.24	1.9	0.23
Hydrocarbons	0.3	0.036	0.3	0.038	0.8	0.096	0.7	0.084
Nitrogen oxides ^c	12.1	1.45	11.2	1.35	(8 to 12) ^d	(1.0 to 1.5) ^d	(7 to 11) ^d	(0.8 to 1.3) ^d

^aLPG emission factors calculated assuming emissions (excluding sulfur oxides) are the same, on a heat input basis, as for natural gas combustion.

^bS equals sulfur content expressed in grains per 100 ft³ gas vapor; e.g., if the sulfur content is 0.16 grain per 100 ft³ (0.366 g/100 m³) vapor, the SO₂ emission factor would be 0.09 x 0.16 or 0.014 lb SO₂ per 1000 gallons (0.01 x 0.366 or 0.0018 kg SO₂/10³ liters) butane burned.

^cExpressed as NO₂.

^dUse lower value for domestic units and higher value for commercial units.

1.6.1 General 1-3

Today, the burning of wood/bark waste in boilers is largely confined to those industries where it is available as a by-product. It is burned both to recover heat energy and to alleviate a potential solid waste disposal problem. Wood/bark waste may include large pieces such as slabs, logs, and bark strips as well as smaller pieces such as ends, shavings, and sawdust. Heating values for this waste range from 8000 to 9000 Btu/lb, on a dry basis; however, because of typical moisture contents of 40 to 75 percent, the as-fired heating values for many wood/bark waste materials range as low as 4000 to 6000 Btu/lb. Generally, bark is the major type of waste burned in pulp mills; whereas, a variable mixture of wood and bark waste, or wood waste alone, is most frequently burned in the lumber, furniture, and plywood industries.

1.6.2 Firing Practices¹⁻³

A variety of boiler firing configurations are utilized for burning wood/bark waste. One common type in smaller operations is the Dutch Oven, or extension type of furnace with a flat grate. In this unit the fuel is fed through the furnace roof and burned in a cone-shaped pile on the grate. In many other, generally larger, operations, more conventional boilers have been modified to burn wood/bark waste. These units may include spreader stokers with traveling grates, vibrating grate stokers, etc., as well as tangentially fired or cyclone fired boilers. Generally, an auxiliary fuel is burned in these units to maintain constant steam when the waste fuel supply fluctuates and/or to provide more steam than is possible from the waste supply alone.

1.6.3 Emissions^{1,2,4-8}

The major pollutant of concern from wood/bark boilers is particulate matter although other pollutants, particularly carbon monoxide, may be emitted in significant amounts under poor operating conditions. These emissions depend on a number of variables including (1) the composition of the waste fuel burned, (2) the degree of fly-ash reinjection employed, and (3) furnace design and operating conditions.

The composition of wood/bark waste depends largely on the industry from whence it originates. Pulping operations, for instance, produce great quantities of bark that may contain more than 70 percent moisture (by weight) as well as high levels of sand and other noncombustibles. Because of this, bark boilers in pulp mills may emit considerable amounts of particulate matter to the atmosphere unless they are well controlled. On the other hand, some operations such as furniture manufacture, produce a clean, dry (5 to 50 percent moisture) wood waste that results in relatively few particulate emissions when properly burned. Still other operations, such as sawmills, burn a variable mixture of bark and wood waste that results in particulate emissions somewhere in between these two extremes.

Fly-ash reinjection, which is commonly employed in many larger boilers to improve fuel-use efficiency, has a considerable effect on particulate emissions. Because a fraction of the collected fly-ash is reinjected into the boiler, the dust loading from the furnace, and consequently from the collection device, increases significantly per ton of wood waste burned. It is reported that full reinjection can cause a 10-fold increase in the dust loadings of some systems although increases of 1.2 to 2 times are more typical for boilers employing 50 to 100 percent reinjection. A major factor affecting this dust loading increase is the extent to which the sand and other non-combustibles can be successfully separated from the fly-ash before reinjection to the furnace.

Furnace design and operating conditions are particularly important when burning wood and bark waste. For example, because of the high moisture content in this waste, a larger area of refractory surface should be provided to dry the fuel prior to combustion. In addition, sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the waste. When proper drying conditions

do not exist, or when sufficient secondary air is not available, the combustion temperature is lowered, incomplete combustion occurs, and increased particulate, carbon monoxide, and hydrocarbon emissions will result.

Emission factors for wood waste boilers are presented in Table 1.6-1. For boilers where fly-ash reinjection is employed, two factors are shown: the first represents the dust loading reaching the control equipment; the value in parenthesis represents the dust loading after controls assuming about 80 percent control efficiency. All other factors represent uncontrolled emissions.

Table 1.6-1. EMISSION FACTORS FOR WOOD AND BARK WASTE COMBUSTION IN BOILERS
EMISSION FACTOR RATING: B

Pollutant	Emissions	
	lb/ton	kg/MT
Particulates ^a		
Bark ^{b,c}		
With fly-ash reinjection ^d	75 (15)	37.5 (7.5)
Without fly-ash reinjection	50	25
Wood/bark mixture ^{b,e}		
With fly-ash reinjection ^d	45 (9)	22.5 (4.5)
Without fly-ash reinjection	30	15
Wood ^{f,g}	5-15	2.5-7.5
Sulfur oxides (SO ₂) ^{h,i}	1.5	0.75
Carbon monoxide ^j	2-60	1-30
Hydrocarbons ^k	2-70	1-35
Nitrogen oxides (NO ₂) ^l	10	5

^aThese emission factors were determined for boilers burning gas or oil as an auxiliary fuel, and it was assumed all particulates resulted from the waste fuel alone. When coal is burned as an auxiliary fuel, the appropriate emission factor from Table 1.1-2 should be used in addition to the above factor.

^bThese factors based on an as-fired moisture content of 50 percent.

^cReferences 2, 4, 9.

^dThis factor represents a typical dust loading reaching the control equipment for boilers employing fly-ash reinjection. The value in parenthesis represents emissions after the control equipment assuming an average efficiency of 80 percent.

^eReferences 7, 10.

^fThis waste includes clean, dry (5 to 50 percent moisture) sawdust, shavings, ends, etc., and no bark. For well designed and operated boilers use lower value and higher values for others. This factor is expressed on an as-fired moisture content basis assuming no fly-ash reinjection.

^gReferences 11-13.

^hThis factor is calculated by material balance assuming a maximum sulfur content of 0.1 percent in the waste. When auxiliary fuels are burned, the appropriate factors from Tables 1.1-2, 1.3-1, or 1.4-1 should be used in addition to determine sulfur oxide emissions.

ⁱReferences 1, 5, 7.

^jThis factor is based on engineering judgment and limited data from references 11 through 13. Use lower values for well designed and operated boilers.

^kThis factor is based on limited data from references 13 through 15. Use lower values for well designed and operated boilers.

^lReference 18.

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1.7 LIGNITE COMBUSTION

by Thomas Lahre

1.7.1 General¹⁻⁴

Lignite is a geologically young coal whose properties are intermediate to those of bituminous coal and peat. It has a high moisture content (35 to 40 percent, by weight) and a low heating value (6000 to 7500 Btu/lb, wet basis) and is generally only burned close to where it is mined, that is, in the midwestern States centered about North Dakota and in Texas. Although a small amount is used in industrial and domestic situations, lignite is mainly used for steam-electric production in power plants. In the past, lignite was mainly burned in small stokers; today the trend is toward use in much larger pulverized-coal-fired or cyclone-fired boilers.

The major advantage to firing lignite is that, in certain geographical areas, it is plentiful, relatively low in cost, and low in sulfur content (0.4 to 1 percent by weight, wet basis). Disadvantages are that more fuel and larger facilities are necessary to generate each megawatt of power than is the case with bituminous coal. There are several reasons for this. First, the higher moisture content of lignite means that more energy is lost in the gaseous products of combustion, which reduces boiler efficiency. Second, more energy is required to grind lignite to the specified size needed for combustion, especially in pulverized coal-fired units. Third, greater tube spacing and additional soot blowing are required because of the higher ash-fouling tendencies of lignite. Fourth, because of its lower heating value, more fuel must be handled to produce a given amount of power because lignite is not generally cleaned or dried prior to combustion (except for some drying that may occur in the crusher or pulverizer and during subsequent transfer to the burner). Generally, no major problems exist with the handling or combustion of lignite when its unique characteristics are taken into account.

1.7.2 Emissions and Controls²⁻⁸

The major pollutants of concern when firing lignite, as with any coal, are particulates, sulfur oxides, and nitrogen oxides. Hydrocarbon and carbon monoxide emissions are usually quite low under normal operating conditions.

Particulate emissions appear most dependent on the firing configuration in the boiler. Pulverized-coal-fired units and spreader stokers, which fire all or much of the lignite in suspension, emit the greatest quantity of flyash per unit of fuel burned. Both cyclones, which collect much of the ash as molten slag in the furnace itself, and stokers (other than spreader stokers), which retain a large fraction of the ash in the fuel bed, emit less particulate matter. In general, the higher sodium content of lignite, relative to other coals, lowers particulate emissions by causing much of the resulting flyash to deposit on the boiler tubes. This is especially the case in pulverized-coal-fired units wherein a high fraction of the ash is suspended in the combustion gases and can readily come into contact with the boiler surfaces.

Nitrogen oxides emissions are mainly a function of the boiler firing configuration and excess air. Cyclones produce the highest NO_x levels, primarily because of the high heat-release rates and temperatures reached in the small furnace sections of the boiler. Pulverized-coal-fired boilers produce less NO_x than cyclones because combustion occurs over a larger volume, which results in lower peak flame temperatures. Tangentially fired boilers produce the lowest NO_x levels in this category. Stokers produce the lowest NO_x levels mainly because most existing units are much smaller than the other firing types. In most boilers, regardless of firing configuration, lower excess air during combustion results in lower NO_x emissions.

Sulfur oxide emissions are a function of the alkali (especially sodium) content of the lignite ash. Unlike most fossil fuel combustion, in which over 90 percent of the fuel sulfur is emitted as SO_2 , a significant fraction of the sulfur in lignite reacts with the ash components during combustion and is retained in the boiler ash deposits and flyash. Tests have shown that less than 50 percent of the available sulfur may be emitted as SO_2 when a high-sodium lignite is burned, whereas, more than 90 percent may be emitted with low-sodium lignite. As a rough average, about 75 percent of the fuel sulfur will be emitted as SO_2 , with the remainder being converted to various sulfate salts.

Air pollution controls on lignite-fired boilers in the United States have mainly been limited to cyclone collectors, which typically achieve 60 to 75 percent collection efficiency on lignite flyash. Electrostatic precipitators, which are widely utilized in Europe on lignitic coals and can effect 99+ percent particulate control, have seen only limited application in the United States to date although their use will probably become widespread on newer units in the future.

Nitrogen oxides reduction (up to 40 percent) has been demonstrated using low excess air firing and staged combustion (see section 1.4 for a discussion of these techniques); it is not yet known, however, whether these techniques can be continuously employed on lignite combustion units without incurring operational problems. Sulfur oxides reduction (up to 50 percent) and some particulate control can be achieved through the use of high sodium lignite. This is not generally considered a desirable practice, however, because of the increased ash fouling that may result.

Emission factors for lignite combustion are presented in Table 1.7-1.

Table 1.7-1. EMISSIONS FROM LIGNITE COMBUSTION WITHOUT CONTROL EQUIPMENT^a
EMISSION FACTOR RATING: B

Pollutant	Type of boiler							
	Pulverized-coal		Cyclone		Spreader stoker		Other stokers	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Particulate ^b	7.0A ^c	3.5A ^c	6A	3A	7.0A ^d	3.5A ^d	3.0A	1.5A
Sulfur oxides ^e	30S	15S	30S	15S	30S	15S	30S	15S
Nitrogen oxides ^f	14(8)9 ^h	7(4)9 ^h	17	8.5	6	3	6	3
Hydrocarbons ⁱ	<1.0	<0.5	<1.0	<0.5	1.0	0.5	1.0	0.5
Carbon monoxide ⁱ	1.0	0.5	1.0	0.5	2	1	2	1

^aAll emission factors are expressed in terms of pounds of pollutant per ton (kilograms of pollutant per metric ton) of lignite burned, wet basis (35 to 40 percent moisture, by weight).

^bA is the ash content of the lignite by weight, wet basis. Factors based on References 5 and 6.

^cThis factor is based on data for dry-bottom, pulverized-coal-fired units only. It is expected that this factor would be lower for wet-bottom units.

^dLimited data preclude any determination of the effect of flyash reinjection. It is expected that particulate emissions would be greater when reinjection is employed.

^eS is the sulfur content of the lignite by weight, wet basis. For a high sodium-ash lignite ($\text{Na}_2\text{O} > 8$ percent) use 17S lb/ton (8.5S kg/MT); for a low sodium-ash lignite ($\text{Na}_2\text{O} < 2$ percent), use 35S lb/ton (17.5S kg/MT). For intermediate sodium-ash lignite, or when the sodium-ash content is unknown, use 30S lb/ton (15S kg/MT). Factors based on References 2, 5, and 6.

^fExpressed as NO_2 . Factors based on References 2, 3, 5, 7, and 9.

^gUse 14 lb/ton (7 kg/MT) for front-wall-fired and horizontally opposed wall-fired units and 8 lb/ton (4 kg/MT) for tangentially fired units.

^hNitrogen oxide emissions may be reduced by 20 to 40 percent with low excess air firing and/or staged combustion in front-fired and opposed-wall-fired units and cyclones.

ⁱThese factors are based on the similarity of lignite combustion to bituminous coal combustion and on limited data in Reference 7.

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1.8 BAGASSE COMBUSTION IN SUGAR MILLS

by Tom Lahre

1.8.1 General¹

Bagasse is the fibrous residue from sugar cane that has been processed in a sugar mill. (See Section 6.12 for a brief general description of sugar cane processing.) It is fired in boilers to eliminate a large solid waste disposal problem and to produce steam and electricity to meet the mill's power requirements. Bagasse represents about 30 percent of the weight of the raw sugar cane. Because of the high moisture content (usually at least 50 percent, by weight) a typical heating value of wet bagasse will range from 3000 to 4000 Btu/lb (1660 to 2220 kcal/kg). Fuel oil may be fired with bagasse when the mill's power requirements cannot be met by burning only bagasse or when bagasse is too wet to support combustion.

The United States sugar industry is located in Florida, Louisiana, Hawaii, Texas, and Puerto Rico. Except in Hawaii, where raw sugar production takes place year round, sugar mills operate seasonally, from 2 to 5 months per year.

Bagasse is commonly fired in boilers employing either a solid hearth or traveling grate. In the former, bagasse is gravity fed through chutes and forms a pile of burning fibers. The burning occurs on the surface of the pile with combustion air supplied through primary and secondary ports located in the furnace walls. This kind of boiler is common in older mills in the sugar cane industry. Newer boilers, on the other hand, may employ traveling-grate stokers. Underfire air is used to suspend the bagasse, and overfired air is supplied to complete combustion. This kind of boiler requires bagasse with a higher percentage of fines, a moisture content not over 50 percent, and more experienced operating personnel.

1.8.2 Emissions and Controls¹

Particulate is the major pollutant of concern from bagasse boilers. Unless an auxiliary fuel is fired, few sulfur oxides will be emitted because of the low sulfur content (<0.1 percent, by weight) of bagasse. Some nitrogen oxides are emitted, although the quantities appear to be somewhat lower (on an equivalent heat input basis) than are emitted from conventional fossil fuel boilers.

Particulate emissions are reduced by the use of multi-cyclones and wet scrubbers. Multi-cyclones are reportedly 20 to 60 percent efficient on particulate from bagasse boilers, whereas scrubbers (either venturi or the spray impingement type) are usually 90 percent or more efficient. Other types of control equipment have been investigated but have not been found to be practical.

Emission factors for bagasse fired boilers are shown in Table 1.8-1.

Table 1.3-1. EMISSION FACTORS FOR UNCONTROLLED BAGASSE BOILERS
EMISSION FACTOR RATING: C

	Emission factors			
	lb/10 ³ lb steam ^a	g/kg steam ^a	lb/ton bagasse ^b	kg/MT bagasse ^b
Particulate ^c	4	4	16	8
Sulfur oxides	d	d	d	d
Nitrogen oxides ^e	0.3	0.3	1.2	0.6

^a Emission factors are expressed in terms of the amount of steam produced, as most mills do not monitor the amount of bagasse fired. These factors should be applied only to that fraction of steam resulting from bagasse combustion. If a significant amount (>25% of total Btu input) of fuel oil is fired with the bagasse, the appropriate emission factors from Table 1.3-1 should be used to estimate the emission contributions from the fuel oil.

^b Emissions are expressed in terms of wet bagasse, containing approximately 50 percent moisture, by weight. As a rule of thumb, about 2 pounds (2 kg) of steam are produced from 1 pound (1 kg) of wet bagasse.

^c Multi-cyclones are reportedly 20 to 60 percent efficient on particulate from bagasse boilers. Wet scrubbers are capable of effecting 90 or more percent particulate control. Based on Reference 1.

^d Sulfur oxide emissions from the firing of bagasse alone would be expected to be negligible as bagasse typically contains less than 0.1 percent sulfur, by weight. If fuel oil is fired with bagasse, the appropriate factors from Table 1.3-1 should be used to estimate sulfur oxide emissions.

^e Based on Reference 1.

Reference for Section 1.8

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1.9 RESIDENTIAL FIREPLACES

by Tom Lahre

1.9.1 General^{1,2}

Fireplaces are utilized mainly in homes, lodges, etc., for supplemental heating and for their aesthetic effect. Wood is most commonly burned in fireplaces; however, coal, compacted wood waste "logs," paper, and rubbish may all be burned at times. Fuel is generally added to the fire by hand on an intermittent basis.

Combustion generally takes place on a raised grate or on the floor of the fireplace. Combustion air is supplied by natural draft, and may be controlled, to some extent, by a damper located in the chimney directly above the firebox. It is common practice for dampers to be left completely open during the fire, affording little control of the amount of air drawn up the chimney.

Most fireplaces heat a room by radiation, with a significant fraction of the heat released during combustion (estimated at greater than 70 percent) lost in the exhaust gases or through the fireplace walls. In addition, as with any fuel-burning, space-heating device, some of the resulting heat energy must go toward warming the air that infiltrates into the residence to make up for the air drawn up the chimney. The net effect is that fireplaces are extremely inefficient heating devices. Indeed, in cases where combustion is poor, where the outside air is cold, or where the fire is allowed to smolder (thus drawing air into a residence without producing appreciable radiant heat energy) a net heat loss may occur in a residence due to the use of a fireplace. Fireplace efficiency may be improved by a number of devices that either reduce the excess air rate or transfer some of the heat back into the residence that is normally lost in the exhaust gases or through the fireplace walls.

1.9.2 Emissions^{1,2}

The major pollutants of concern from fireplaces are unburnt combustibles—carbon monoxide and smoke. Significant quantities of these pollutants are produced because fireplaces are grossly inefficient combustion devices due to high, uncontrolled excess air rates, low combustion temperatures, and the absence of any sort of secondary combustion. The last of these is especially important when burning wood because of its typically high (80 percent, on a dry weight basis)³ volatile matter content.

Because most wood contains negligible sulfur, very few sulfur oxides are emitted. Sulfur oxides will be produced, of course, when coal or other sulfur-bearing fuels are burned. Nitrogen oxide emissions from fireplaces are expected to be negligible because of the low combustion temperatures involved.

Emission factors for wood and coal combustion in residential fireplaces are given in Table 1.9-1.

Table 1.9-1. EMISSION FACTORS FOR RESIDENTIAL FIREPLACES
EMISSION FACTOR RATING: C

Pollutant	Wood		Coal ^a	
	lb/ton	kg/MT	lb/ton	kg/MT
Particulate	20 ^b	10 ^b	30 ^c	15 ^c
Sulfur oxides	0 ^d	0 ^d	36S ^e	36S ^e
Nitrogen oxides	1 ^f	0.5 ^f	3	1.5
Hydrocarbons	5 ^g	2.5 ^g	20	10
Carbon monoxide	120 ^h	60 ^h	90	45

^aAll coal emission factors, except particulate, are based on data in Table 1.1-2 of Section 1.1 for hand-fired units.

^bThis includes condensable particulate. Only about 30 percent of this is filterable particulate as determined by EPA Method 5 (front-half catch).⁴ Based on limited data from Reference 1.

^cThis includes condensable particulate. About 50 percent of this is filterable particulate as determined by EPA Method 5 (front-half catch).⁴ Based on limited data from Reference 1.

^dBased on negligible sulfur content in most wood.³

^eS is the sulfur content, on a weight percent basis, of the coal.

^fBased on data in Table 2.3-1 in Section 2.3 for wood waste combustion in conical burners.

^gNonmethane volatile hydrocarbons. Based on limited data from Reference 1.

^hBased on limited data from Reference 1.

References for Section 1.9

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2. SOLID WASTE DISPOSAL

Revised by Robert Rosensteel

As defined in the Solid Waste Disposal Act of 1965, the term "solid waste" means garbage, refuse, and other discarded solid materials, including solid-waste materials resulting from industrial, commercial, and agricultural operations, and from community activities. It includes both combustibles and noncombustibles.

Solid wastes may be classified into four general categories: urban, industrial, mineral, and agricultural. Although urban wastes represent only a relatively small part of the total solid wastes produced, this category has a large potential for air pollution since in heavily populated areas solid waste is often burned to reduce the bulk of material requiring final disposal.¹ The following discussion will be limited to the urban and industrial waste categories.

An average of 5.5 pounds (2.5 kilograms) of urban refuse and garbage is collected per capita per day in the United States.² This figure does not include uncollected urban and industrial wastes that are disposed of by other means. Together, uncollected urban and industrial wastes contribute at least 4.5 pounds (2.0 kilograms) per capita per day. The total gives a conservative per capita generation rate of 10 pounds (4.5 kilograms) per day of urban and industrial wastes. Approximately 50 percent of all the urban and industrial waste generated in the United States is burned, using a wide variety of combustion methods with both enclosed and open burning³. Atmospheric emissions, both gaseous and particulate, result from refuse disposal operations that use combustion to reduce the quantity of refuse. Emissions from these combustion processes cover a wide range because of their dependence upon the refuse burned, the method of combustion or incineration, and other factors. Because of the large number of variables involved, it is not possible, in general, to delineate when a higher or lower emission factor, or an intermediate value should be used. For this reason, an average emission factor has been presented.

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3. Nationwide Inventory of Air Pollutant Emissions, 1968. U.S. DHEW, PHS, EHS, National Air Pollution Control Administration. Raleigh, N.C. Publication Number AP-73. August 1970.

2.1 REFUSE INCINERATION

Revised by Robert Rosensteel

2.1.1 Process Description¹⁻⁴

The most common types of incinerators consist of a refractory-lined chamber with a grate upon which refuse is burned. In some newer incinerators water-walled furnaces are used. Combustion products are formed by heating and burning of refuse on the grate. In most cases, since insufficient underfire (undergrate) air is provided to enable complete combustion, additional over-fire air is admitted above the burning waste to promote complete gas-phase combustion. In multiple-chamber incinerators, gases from the primary chamber flow to a small secondary mixing chamber where more air is admitted, and more complete oxidation occurs. As much as 300 percent excess air may be supplied in order to promote oxidation of combustibles. Auxiliary burners are sometimes installed in the mixing chamber to increase the combustion temperature. Many small-size incinerators are single-chamber units in which gases are vented from the primary combustion chamber directly into the exhaust stack. Single-chamber incinerators of this type do not meet modern air pollution codes.

2.1.2 Definitions of Incinerator Categories¹

No exact definitions of incinerator size categories exist, but for this report the following general categories and descriptions have been selected:

1. *Municipal incinerators* — Multiple-chamber units often have capacities greater than 50 tons (45.3 MT) per day and are usually equipped with automatic charging mechanisms, temperature controls, and movable grate systems. Municipal incinerators are also usually equipped with some type of particulate control device, such as a spray chamber or electrostatic precipitator.
2. *Industrial/commercial incinerators* — The capacities of these units cover a wide range, generally between 50 and 4,000 pounds (22.7 and 1,800 kilograms) per hour. Of either single- or multiple-chamber design, these units are often manually charged and intermittently operated. Some industrial incinerators are similar to municipal incinerators in size and design. Better designed emission control systems include gas-fired afterburners or scrubbing, or both.
3. *Trench Incinerators* — A trench incinerator is designed for the combustion of wastes having relatively high heat content and low ash content. The design of the unit is simple: a U-shaped combustion chamber is formed by the sides and bottom of the pit and air is supplied from nozzles along the top of the pit. The nozzles are directed at an angle below the horizontal to provide a curtain of air across the top of the pit and to provide air for combustion in the pit. The trench incinerator is not as efficient for burning wastes as the municipal multiple-chamber unit, except where careful precautions are taken to use it for disposal of low-ash, high-heat-content refuse, and where special attention is paid to proper operation. Low construction and operating costs have resulted in the use of this incinerator to dispose of materials other than those for which it was originally designed. Emission factors for trench incinerators used to burn three such materials⁷ are included in Table 2.1-1.
4. *Domestic incinerators* — This category includes incinerators marketed for residential use. Fairly simple in design, they may have single or multiple chambers and usually are equipped with an auxiliary burner to aid combustion.

EMISSION FACTORS

Table 2.1-1. EMISSION FACTORS FOR REFUSE INCINERATORS WITHOUT CONTROLS^a
EMISSION FACTOR RATING: A

Incinerator type	Particulates		Sulfur oxides ^b		Carbon monoxide		Hydrocarbons ^c		Nitrogen oxides ^d	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Municipal^e										
Multiple chamber, uncontrolled	30	15	2.5	1.25	35	17.5	1.5	0.75	3	1.5
With settling chamber and water spray system ^f	14	7	2.5	1.25	35	17.5	1.5	0.75	3	1.5
Industrial/commercial										
Multiple chamber ^g	7	3.5	2.5 ^h	1.25	10	5	3	1.5	3	1.5
Single chamber ⁱ	15	7.5	2.5 ^h	1.25	20	10	15	7.5	2	1
Trench ^j										
Wood	13	6.5	0.1 ^k	0.05	NA ^l	NA	NA	NA	4	2
Rubber tires	138	69	NA	NA	NA	NA	NA	NA	NA	NA
Municipal refuse	37	18.5	2.5 ^h	1.25	NA	NA	NA	NA	NA	NA
Controlled air ^m	1.4	0.7	1.5	0.75	Neg	Neg	Neg	Neg	10	5
Flue-fed single chamber ⁿ	30	15	0.5	0.25	20	10	15	7.5	3	1.5
Flue-fed (modified) ^{o,p}	6	3	0.5	0.25	10	5	3	1.5	10	5
Domestic single chamber										
Without primary burner ^q	35	17.5	0.5	0.25	300	150	100	50	1	0.5
With primary burner ^r	7	3.5	0.5	0.25	Neg	Neg	2	1	2	1
Pathological ^s	8	4	Neg	Neg	Neg	Neg	Neg	Neg	3	1.5

^a Average factors given based on EPA procedures for incinerator stack testing.

^b Expressed as sulfur dioxide.

^c Expressed as methane.

^d Expressed as nitrogen dioxide.

^e References 5 and 8 through 14.

^f Most municipal incinerators are equipped with at least this much control: see Table 2.1-2 for appropriate efficiencies for other controls.

^g References 3, 5, 10, 13, and 15.

^h Based on municipal incinerator data.

ⁱ References 3, 5, 10, and 15.

^j Reference 7.

^k Based on data for wood combustion in conical burners.

^l Not available.

^m Reference 9.

ⁿ References 3, 10, 11, 13, 15, and 16.

^o With afterburners and draft controls.

^p References 3, 11, and 15.

^q References 5 and 10.

^r Reference 5.

^s References 3 and 9.

5. *Flue-fed incinerators* – These units, commonly found in large apartment houses, are characterized by the charging method of dropping refuse down the incinerator flue and into the combustion chamber. Modified flue-fed incinerators utilize afterburners and draft controls to improve combustion efficiency and reduce emissions.
6. *Pathological incinerators* – These are incinerators used to dispose of animal remains and other organic material of high moisture content. Generally, these units are in a size range of 50 to 100 pounds (22.7 to 45.4 kilograms) per hour. Wastes are burned on a hearth in the combustion chamber. The units are equipped with combustion controls and afterburners to ensure good combustion and minimal emissions.
7. *Controlled air incinerators* – These units operate on a controlled combustion principle in which the waste is burned in the absence of sufficient oxygen for complete combustion in the main chamber. This process generates a highly combustible gas mixture that is then burned with excess air in a secondary chamber, resulting in efficient combustion. These units are usually equipped with automatic charging mechanisms and are characterized by the high effluent temperatures reached at the exit of the incinerators.

2.1.3 Emissions and Controls¹

Operating conditions, refuse composition, and basic incinerator design have a pronounced effect on emissions. The manner in which air is supplied to the combustion chamber or chambers has, among all the parameters, the greatest effect on the quantity of particulate emissions. Air may be introduced from beneath the chamber, from the side, or from the top of the combustion area. As underfire air is increased, an increase in fly-ash emissions occurs. Erratic refuse charging causes a disruption of the combustion bed and a subsequent release of large quantities of particulates. Large quantities of uncombusted particulate matter and carbon monoxide are also emitted for an extended period after charging of batch-fed units because of interruptions in the combustion process. In continuously fed units, furnace particulate emissions are strongly dependent upon grate type. The use of rotary kiln and reciprocating grates results in higher particulate emissions than the use of rocking or traveling grates.¹⁴ Emissions of oxides of sulfur are dependent on the sulfur content of the refuse. Carbon monoxide and unburned hydrocarbon emissions may be significant and are caused by poor combustion resulting from improper incinerator design or operating conditions. Nitrogen oxide emissions increase with an increase in the temperature of the combustion zone, an increase in the residence time in the combustion zone before quenching, and an increase in the excess air rates to the point where dilution cooling overcomes the effect of increased oxygen concentration.¹⁴

Table 2.1-2 lists the relative collection efficiencies of particulate control equipment used for municipal incinerators. This control equipment has little effect on gaseous emissions. Table 2.1-1 summarizes the uncontrolled emission factors for the various types of incinerators previously discussed.

Table 2.1-2. COLLECTION EFFICIENCIES FOR VARIOUS TYPES OF MUNICIPAL INCINERATION PARTICULATE CONTROL SYSTEMS^a

Type of system	Efficiency, %
Settling chamber	0 to 30
Settling chamber and water spray	30 to 60
Wetted baffles	60
Mechanical collector	30 to 80
Scrubber	80 to 95
Electrostatic precipitator	90 to 96
Fabric filter	97 to 99

^aReferences 3, 5, 6, and 17 through 21.

EMISSION FACTORS

References for Section 2.1

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EMISSION FACTORS

2.2 AUTOMOBILE BODY INCINERATION

Revised by Robert Rosensteel

2.2.1 Process Description

Auto incinerators consist of a single primary combustion chamber in which one or several partially stripped cars are burned. (Tires are removed.) Approximately 30 to 40 minutes is required to burn two bodies simultaneously.² As many as 50 cars per day can be burned in this batch-type operation, depending on the capacity of the incinerator. Continuous operations in which cars are placed on a conveyor belt and passed through a tunnel-type incinerator have capacities of more than 50 cars per 8-hour day.

2.2.2 Emissions and Controls¹

Both the degree of combustion as determined by the incinerator design and the amount of combustible material left on the car greatly affect emissions. Temperatures on the order of 1200°F (650°C) are reached during auto body incineration.² This relatively low combustion temperature is a result of the large incinerator volume needed to contain the bodies as compared with the small quantity of combustible material. The use of overfire air jets in the primary combustion chamber increases combustion efficiency by providing air and increased turbulence.

In an attempt to reduce the various air pollutants produced by this method of burning, some auto incinerators are equipped with emission control devices. Afterburners and low-voltage electrostatic precipitators have been used to reduce particulate emissions; the former also reduces some of the gaseous emissions.^{3,4} When afterburners are used to control emissions, the temperature in the secondary combustion chamber should be at least 1500°F (815°C). Lower temperatures result in higher emissions. Emission factors for auto body incinerators are presented in Table 2.2-1.

Table 2.2-1. EMISSION FACTORS FOR AUTO BODY INCINERATION*
EMISSION FACTOR RATING: B

Pollutants	Uncontrolled		With afterburner	
	lb/car	kg/car	lb/car	kg/car
Particulates ^b	2	0.9	1.5	0.68
Carbon monoxide ^c	2.5	1.1	Neg	Neg
Hydrocarbons (CH ₄) ^c	0.5	0.23	Neg	Neg
Nitrogen oxides (NO ₂) ^d	0.1	0.05	0.02	0.01
Aldehydes (HCOH) ^d	0.2	0.09	0.06	0.03
Organic acids (acetic) ^d	0.21	0.10	0.07	0.03

*Based on 250 lb (113 kg) of combustible material on stripped car body.

^bReferences 2 and 4.

^cBased on data for open burning and References 2 and 5.

^dReference 3.

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EMISSION FACTORS

2.3 CONICAL BURNERS

2.3.1 Process Description¹

Conical burners are generally a truncated metal cone with a screened top vent. The charge is placed on a raised grate by either conveyor or bulldozer; however, the use of a conveyor results in more efficient burning. No supplemental fuel is used, but combustion air is often supplemented by underfire air blown into the chamber below the grate and by overfire air introduced through peripheral openings in the shell.

2.3.2 Emissions and Controls

The quantities and types of pollutants released from conical burners are dependent on the composition and moisture content of the charged material, control of combustion air, type of charging system used, and the condition in which the incinerator is maintained. The most critical of these factors seems to be the level of maintenance on the incinerators. It is not uncommon for conical burners to have missing doors and numerous holes in the shell, resulting in excessive combustion air, low temperatures, and, therefore, high emission rates of combustible pollutants.²

Particulate control systems have been adapted to conical burners with some success. These control systems include water curtains (wet caps) and water scrubbers. Emission factors for conical burners are shown in Table 2.3-1.

**Table 2.3-1. EMISSION FACTORS FOR WASTE INCINERATION IN CONICAL BURNERS
WITHOUT CONTROLS^a
EMISSION FACTOR RATING: B**

Type of waste	Particulates		Sulfur oxides		Carbon monoxide		Hydrocarbons		Nitrogen oxides	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Municipal refuse ^b	20(10 to 60) ^{c,d}	10	2	1	60	30	20	10	5	2.5
Wood refuse ^e	1 ^f	0.5	0.1	0.05	130	65	11	5.5	1	0.5
	7 ^g	3.5								
	20 ^h	10								

^aMoisture content as fired is approximately 60 percent for wood waste.

^bExcept for particulates, factors are based on comparison with other waste disposal practices.

^cUse high side of range for Intermittent operations charged with a bulldozer.

^dBased on Reference 3.

^eReferences 4 through 9.

^fSatisfactory operation: properly maintained burner with adjustable underfire air supply and adjustable, tangential overfire air inlets, approximately 500 percent excess air and 700°F (370°C) exit gas temperature.

^gUnsatisfactory operation: properly maintained burner with radial overfire air supply near bottom of shell, approximately 1200 percent excess air and 400°F (204°C) exit gas temperature.

^hVery unsatisfactory operation: Improperly maintained burner with radial overfire air supply near bottom of shell and many gaping holes in shell, approximately 1500 percent excess air and 400°F (204°C) exit gas temperature.

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2.4 OPEN BURNING

revised by Tom Lahre
and Pam Canova

2.4.1 General¹

Open burning can be done in open drums or baskets, in fields and yards, and in large open dumps or pits. Materials commonly disposed of in this manner are municipal waste, auto body components, landscape refuse, agricultural field refuse, wood refuse, bulky industrial refuse, and leaves.

2.4.2 Emissions¹⁻¹⁹

Ground-level open burning is affected by many variables including wind, ambient temperature, composition and moisture content of the debris burned, and compactness of the pile. In general, the relatively low temperatures associated with open burning increase the emission of particulates, carbon monoxide, and hydrocarbons and suppress the emission of nitrogen oxides. Sulfur oxide emissions are a direct function of the sulfur content of the refuse. Emission factors are presented in Table 2.4-1 for the open burning of municipal refuse and automobile components.

Table 2.4-1. EMISSION FACTORS FOR OPEN BURNING OF NONAGRICULTURAL MATERIAL
EMISSION FACTOR RATING: B

	Particulates	Sulfur oxides	Carbon monoxide	Hydrocarbons (CH ₄)	Nitrogen oxides
Municipal refuse ^a					
lb/ton	16	1	85	30	6
kg/MT	8	0.5	42	15	3
Automobile components ^{b,c}					
lb/ton	100	Neg.	125	30	4
kg/MT	50	Neg.	62	15	2

^aReferences 2 through 6.

^bUpholstery, belts, hoses, and tires burned in common.

^cReference 2.

Emissions from agricultural refuse burning are dependent mainly on the moisture content of the refuse and, in the case of the field crops, on whether the refuse is burned in a headfire or a backfire. (Headfires are started at the upwind side of a field and allowed to progress in the direction of the wind, whereas backfires are started at the downwind edge and forced to progress in a direction opposing the wind.) Other variables such as fuel loading (how much refuse material is burned per unit of land area) and how the refuse is arranged (that is, in piles, rows, or spread out) are also important in certain instances. Emission factors for open agricultural burning are presented in Table 2.4-2 as a function of refuse type and also, in certain instances, as a function of burning techniques and/or moisture content when these variables are known to significantly affect emissions. Table 2.4-2 also presents typical fuel loading values associated with each type of refuse. These values can be used, along with the corresponding emission factors, to estimate emissions from certain categories of agricultural burning when the specific fuel loadings for a given area are not known.

Emissions from leaf burning are dependent upon the moisture content, density, and ignition location of the leaf piles. Increasing the moisture content of the leaves generally increases the amount of carbon monoxide, hydrocarbon, and particulate emissions. Increasing the density of the piles increases the amount of hydrocarbon and particulate emissions, but has a variable effect on carbon

**Table 2.4-2. EMISSION FACTORS AND FUEL LOADING FACTORS FOR OPEN BURNING
OF AGRICULTURAL MATERIALS^a
EMISSION FACTOR RATING: B**

Refuse category	Emission factors						Fuel loading factors (waste production)	
	Particulate ^b		Carbon monoxide		Hydrocarbons (as C ₆ H ₁₄)			
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	ton/acre	MT/hectare
Field crops ^c								
Unspecified	21	11	117	58	23	12	2.0	4.5
Burning technique not significant ^d								
Asparagus ^e	40	20	150	75	85	42	1.5	3.4
Barley	22	11	157	78	19	10	1.7	3.8
Corn	14	7	108	54	16	8	4.2	9.4
Cotton	8	4	176	88	6	3	1.7	3.8
Grasses	16	8	101	50	19	10		
Pineapple ^f	8	4	112	56	8	4		
Rice ^g	9	4	83	41	10	5	3.0	6.7
Safflower	18	9	144	72	26	13	1.3	2.9
Sorghum	18	9	77	38	9	4	2.9	6.5
Sugar cane ^h	7	4	71	35	10	5	11.0	24.0
Headfire burning ⁱ								
Alfalfa	45	23	106	53	36	18	0.8	1.8
Bean (red)	43	22	186	93	46	23	2.5	5.6
Hay (wild)	32	16	139	70	22	11	1.0	2.2
Oats	44	22	137	68	33	16	1.6	3.6
Pea	31	16	147	74	38	19	2.5	5.6
Wheat	22	11	128	64	17	9	1.9	4.3
Backfire burning ^j								
Alfalfa	29	14	119	60	37	18	0.8	1.8
Bean (red), pea	14	7	148	72	25	12	2.5	5.6
Hay (wild)	17	8	150	75	17	8	1.0	2.2
Oats	21	11	136	68	18	9	1.6	3.6
Wheat	13	6	108	54	11	6	1.9	4.3
Vine crops	5	3	51	26	7	4	2.5	5.6
Weeds								
Unspecified	15	8	85	42	12	6	3.2	7.2
Russian thistle (tumbleweed)	22	11	309	154	2	1	0.1	0.2
Tules (wild reeds)	5	3	34	17	27	14		
Orchard crops ^{c,k,l}								
Unspecified	6	3	52	26	10	5	1.6	3.6
Almond	6	3	46	23	8	4	1.6	3.6
Apple	4	2	42	21	4	2	2.3	5.2
Apricot	6	3	49	24	8	4	1.8	4.0
Avocado	21	10	116	58	32	16	1.5	3.4
Cherry	8	4	44	22	10	5	1.0	2.2
Citrus (orange, lemon)	6	3	81	40	12	6	1.0	2.2
Date palm	10	5	56	28	7	4	1.0	2.2
Fig	7	4	57	28	10	5	2.2	4.9

EMISSION FACTORS

Table 2.4-2 (continued). EMISSION FACTORS AND FUEL LOADING FACTORS FOR OPEN BURNING OF AGRICULTURAL MATERIALS^a
EMISSION FACTOR RATING: B

Refuse category	Emission factors						Fuel loading factors (waste production)	
	Particulate ^b		Carbon monoxide		Hydrocarbons (as C ₆ H ₁₄)			
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT	ton/acre	MT/hectare
Orchard crops ^{c,k,l} (continued)								
Nectarine	4	2	33	16	4	2	2.0	4.5
Olive	12	6	114	57	18	9	1.2	2.7
Peach	6	3	42	21	5	2	2.5	5.6
Pear	9	4	57	28	9	4	2.6	5.8
Prune	3	2	42	21	3	2	1.2	2.7
Walnut	6	3	47	24	8	4	1.2	2.7
Forest residues								
Unspecified ^m	17	8	140	70	24	12	70	157
Hemlock, Douglas fir, cedar ⁿ	4	2	90	45	5	2		
Ponderosa pine ^o	12	6	195	98	14	7		

^aFactors expressed as weight of pollutant emitted per weight of refuse material burned.

^bParticulate matter from most agricultural refuse burning has been found to be in the submicrometer size range.¹²

^cReferences 12 and 13 for emission factors; Reference 14 for fuel loading factors.

^dFor these refuse materials, no significant difference exists between emissions resulting from headfiring or backfiring.

^eThese factors represent emissions under typical high moisture conditions. If ferns are dried to less than 15 percent moisture, particulate emissions will be reduced by 30 percent, CO emission by 23 percent, and HC by 74 percent.

^fWhen pineapple is allowed to dry to less than 20 percent moisture, as it usually is, the firing technique is not important. When headfired above 20 percent moisture, particulate emission will increase to 23 lb/ton (11.5 kg/MT) and HC will increase to 12 lb/ton (6 kg/MT). See Reference 11.

^gThis factor is for dry (<15 percent moisture) rice straw. If rice straw is burned at higher moisture levels, particulate emission will increase to 29 lb/ton (14.5 kg/MT), CO emission to 161 lb/ton (80.5 kg/MT), and HC emission to 21 lb/ton (10.5 kg/MT).

^hSee Section 6.12 for discussion of sugar cane burning.

ⁱSee accompanying text for definition of headfiring.

^jSee accompanying text for definition of backfiring. This category, for emission estimation purposes, includes another technique used occasionally for limiting emissions, called into-the-wind striplighting, which involves lighting fields in strips into the wind at 100-200 m (300-600 ft) intervals.

^kOrchard prunings are usually burned in piles. No significant difference in emission results from burning a "cold pile" as opposed to using a roll-on technique, where prunings are bulldozed onto a bed of embers from a preceding fire.

^lIf orchard removal is the purpose of a burn, 30 ton/acre (66 MT/hectare) of waste will be produced.

^mReference 10. Nitrogen oxide emissions estimated at 4 lb/ton (2 kg/MT).

ⁿReference 15.

^oReference 16.

monoxide emissions. Arranging the leaves in conical piles and igniting around the periphery of the bottom proves to be the least desirable method of burning. Igniting a single spot on the top of the pile decreases the hydrocarbon and particulate emissions. Carbon monoxide emissions with top ignition decrease if moisture content is high but increase if moisture content is low. Particulate, hydrocarbon, and carbon monoxide emissions from windrow ignition (piling the leaves into a long row and igniting one end, allowing it to burn toward the other end) are intermediate between top and bottom ignition. Emission factors for leaf burning are presented in Table 2.4-3.

For more detailed information on this subject, the reader should consult the references cited at the end of this section.

Table 2.4-3. EMISSION FACTORS FOR LEAF BURNING^{18,19}
EMISSION FACTOR RATING: B

Leaf species	Particulate ^{a,b}		Carbon monoxide ^a		Hydrocarbons ^{a,c}	
	lb/ton	kg/MT	lb/ton	kg/MT	lb/ton	kg/MT
Black Ash	36	18	127	63.5	41	20.5
Modesto Ash	32	16	163	81.5	25	12.5
White Ash	43	21.5	113	57	21	10.5
Catalpa	17	8.5	89	44.5	15	7.5
Horse Chestnut	54	27	147	73.5	39	19.5
Cottonwood	38	19	90	45	32	16
American Elm	26	13	119	59.5	29	14.5
Eucalyptus	36	18	90	45	26	13
Sweet Gum	33	16.5	140	70	27	13.5
Black Locust	70	35	130	65	62	31
Magnolia	13	6.5	55	27.5	10	5
Silver Maple	66	33	102	51	25	12.5
American Sycamore	15	7.5	115	57.5	8	4
California Sycamore	10	5	104	52	5	2.5
Tulip	20	10	77	38.5	16	8
Red Oak	92	46	137	68.5	34	17
Sugar Maple	53	26.5	108	54	27	13.5
Unspecified	38	19	112	56	26	13

^aThese factors are an arithmetic average of the results obtained by burning high- and low-moisture content conical piles ignited either at the top or around the periphery of the bottom. The windrow arrangement was only tested on Modesto Ash, Catalpa, American Elm, Sweet Gum, Silver Maple, and Tulip, and the results are included in the averages for these species.

^bThe majority of particulates are submicron in size.

^cTests indicate hydrocarbons consist, on the average, of 42% olefins, 32% methane, 8% acetylene, and 13% other saturates.

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2.5.1 Process Description 1-3

Incineration is becoming an important means of disposal for the increasing amounts of sludge being produced in sewage treatment plants. Incineration has the advantages of both destroying the organic matter present in sludge, leaving only an odorless, sterile ash, as well as reducing the solid mass by about 90 percent. Disadvantages include the remaining, but reduced, waste disposal problem and the potential for air pollution. Sludge incineration systems usually include a sludge pretreatment stage to thicken and dewater the incoming sludge, an incinerator, and some type of air pollution control equipment (commonly wet scrubbers).

The most prevalent types of incinerators are multiple hearth and fluidized bed units. In multiple hearth units the sludge enters the top of the furnace where it is first dried by contact with the hot, rising, combustion gases, and then burned as it moves slowly down through the lower hearths. At the bottom hearth any residual ash is then removed. In fluidized bed reactors, the combustion takes place in a hot, suspended bed of sand with much of the ash residue being swept out with the flue gas. Temperatures in a multiple hearth furnace are 600°F (320°C) in the lower, ash cooling hearth; 1400 to 2000°F (760 to 1100°C) in the central combustion hearths, and 1000 to 1200°F (540 to 650°C) in the upper, drying hearths. Temperatures in a fluidized bed reactor are fairly uniform, from 1250 to 1500°F (680 to 820°C). In both types of furnace an auxiliary fuel may be required either during startup or when the moisture content of the sludge is too high to support combustion.

2.5.2 Emissions and Controls 1,2,4-7

Because of the violent upwards movement of combustion gases with respect to the burning sludge, particulates are the major emissions problem in both multiple hearth and fluidized bed incinerators. Wet scrubbers are commonly employed for particulate control and can achieve efficiencies ranging from 95 to 99+ percent.

Although dry sludge may contain from 1 to 2 percent sulfur by weight, sulfur oxides are not emitted in significant amounts when sludge burning is compared with many other combustion processes. Similarly, nitrogen oxides, because temperatures during incineration do not exceed 1500°F (820°C) in fluidized bed reactors or 1600 to 2000°F (870 to 1100°C) in multiple hearth units, are not formed in great amounts.

Odors can be a problem in multiple hearth systems as unburned volatiles are given off in the upper, drying hearths, but are readily removed when afterburners are employed. Odors are not generally a problem in fluidized bed units as temperatures are uniformly high enough to provide complete oxidation of the volatile compounds. Odors can also emanate from the pretreatment stages unless the operations are properly enclosed.

Emission factors for sludge incinerators are shown in Table 2.5-1. It should be noted that most sludge incinerators operating today employ some type of scrubber.

Table 2.5-1. EMISSION FACTORS FOR SEWAGE SLUDGE INCINERATORS
EMISSION FACTOR RATING: B

Pollutant	Emissions ^a			
	Uncontrolled ^b		After scrubber	
	lb/ton	kg/MT	lb/ton	kg/MT
Particulate ^c	100	50	3	1.5
Sulfur dioxide ^d	1	0.5	0.8	0.4
Carbon monoxide ^e	Neg	Neg	Neg	Neg
Nitrogen oxides ^d (as NO ₂)	6	3	5	2.5
Hydrocarbons ^d	1.5	0.75	1	0.5
Hydrogen chloride gas ^d	1.5	0.75	0.3	0.15

^aUnit weights in terms of dried sludge.

^bEstimated from emission factors after scrubbers.

^cReferences 6-9.

^dReference 8.

^eReferences 6, 8.

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EMISSION FACTORS

Appendix B

Conversion Factors

Length

$$1 \text{ inch} = 2.54 \text{ cm}$$

$$1 \text{ m} = 3.048 \text{ ft}$$

$$1 \text{ ft} = 0.305 \text{ m}$$

Mass

$$1 \text{ lb} = 453.6 \text{ g}$$

$$1 \text{ kg} = 2.2 \text{ lb}$$

Pressure

$$1 \text{ atm} = 101,325 \text{ Pa}$$

$$= 760 \text{ mm Hg (0°C)}$$

$$= 14.7 \text{ psia}$$

Force

$$1 \text{ N} = 1 \text{ kg} \cdot \text{m/s}^2$$

Energy

$$1 \text{ cal} = 4.184 \text{ J}$$

$$1 \text{ J} = 9.48 \times 10^{-4} \text{ Btu}$$

$$1 \text{ Btu} = 252.2 \text{ cal}$$

Kinematic viscosity

$$1 \text{ m}^2/\text{s} = 10^4 \text{ stokes}$$

Power

$$1 \text{ W} = 1 \text{ J/s}$$

$$1 \text{ hp} = 33,479 \text{ Btu/hr}$$

Area

$$1 \text{ cm}^2 = 0.155 \text{ in}^2$$

$$1 \text{ m}^2 = 10.764 \text{ ft}^2$$

Volume

$$1 \text{ cm}^3 = 0.061 \text{ in}^3$$

$$1 \text{ m}^3 = 35.31 \text{ ft}^3$$

$$1 \text{ barrel (oil)} = 42 \text{ gal}$$

$$1 \text{ ft}^3 = 7.48 \text{ gal}$$

$$1 \text{ ft}^3 = 28.317 \text{ liters}$$

Density

$$1 \text{ kg/m}^3 = 0.0624 \text{ lb/ft}^3$$

Dynamic viscosity

$$1 \text{ Pa} \cdot \text{s} = 1 \text{ N} \cdot \text{m/s} = 1000 \text{ centipoise}$$

$$1 \text{ cp} = 0.000672 \text{ lb/ft} \cdot \text{sec}$$

Volume flow

$$1 \text{ m}^3/\text{s} = 35.3 \text{ ft}^3/\text{sec}$$

$$1 \text{ m}^3/\text{min} = 35.3 \text{ ft}^3/\text{min}$$

$$1 \text{ scfm} = 1.7 \text{ m}^3/\text{h}$$

$$1 \text{ gpm} = 0.227 \text{ m}^3/\text{h}$$

Velocity

$$1 \text{ m/s} = 3.048 \text{ ft/sec}$$

$$1 \text{ mi/hr} = 0.447 \text{ m/s}$$

Geometry

$$\text{area of circle} = \pi r^2$$

$$\text{circumference of circle} = 2 \pi r$$

$$\text{surface area of sphere} = 4 \pi r^2$$

$$\text{volume of sphere} = 4/3 \pi r^3$$

$$\text{area of cylinder} = 2 \pi r h$$

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